We are driven

Sierra Pacific™
RESOURCES

2006 ANNUAL REPORT

SIERRA PACIFIC RESOURCES IN BRIEF

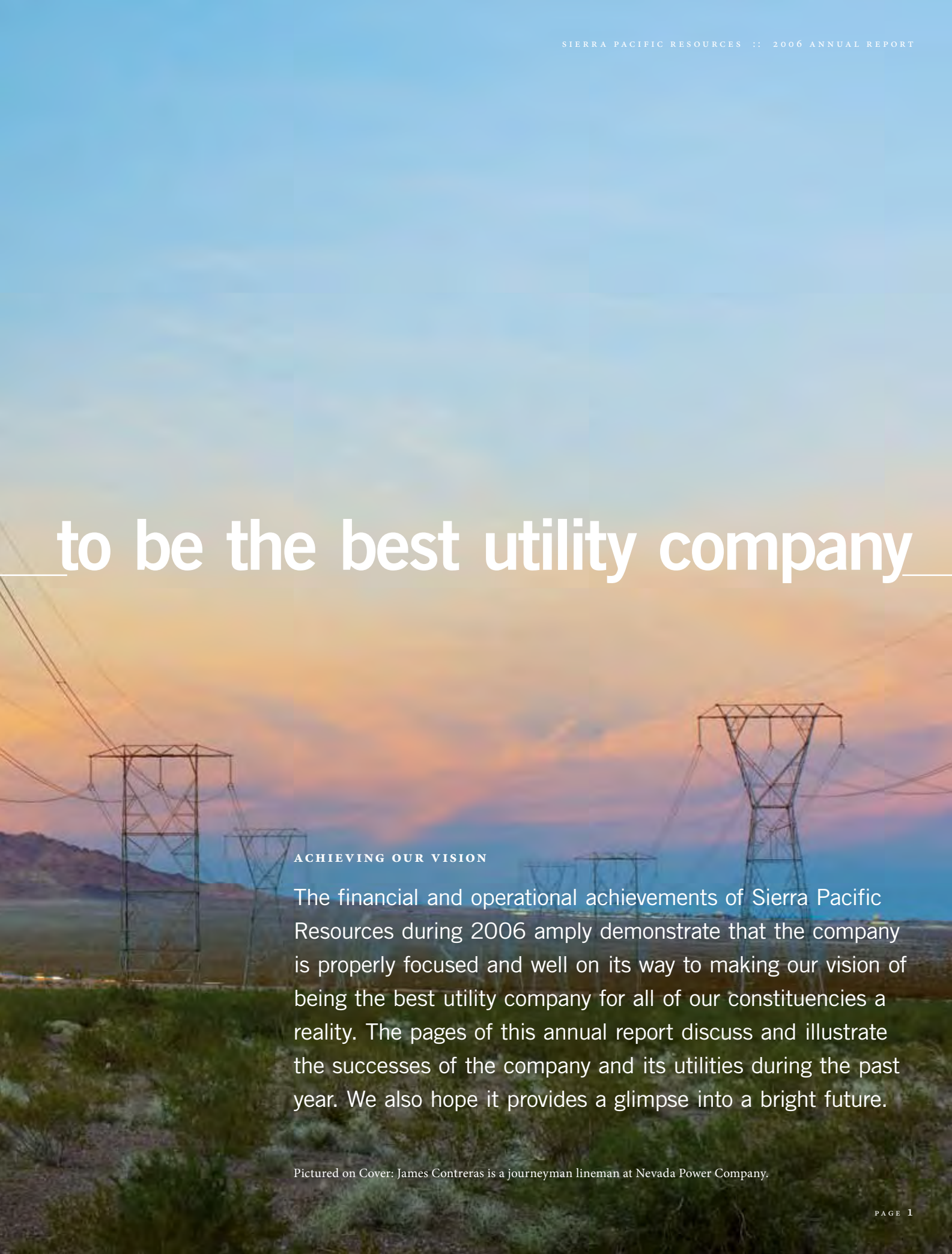
Sierra Pacific Resources is an investor-owned corporation with operating subsidiaries engaged in the utility business, principally in the State of Nevada. The company's stock is traded on the New York Stock Exchange under the symbol SRP.

Chief operating subsidiaries are Nevada Power Company, which serves approximately 807,000 electric customers in Las Vegas and surrounding areas of southern Nevada; and Sierra Pacific Power Company, which has approximately 361,000 electric customers in northern Nevada and the Lake Tahoe area of northern California, and provides natural gas service to approximately 146,000 customers in the Reno–Sparks metropolitan area of northern Nevada.

The combined service area of the two utilities covers approximately 54,500 square miles.

The number of registered holders of Sierra Pacific Resources' common stock was 17,515 as of December 31, 2006.

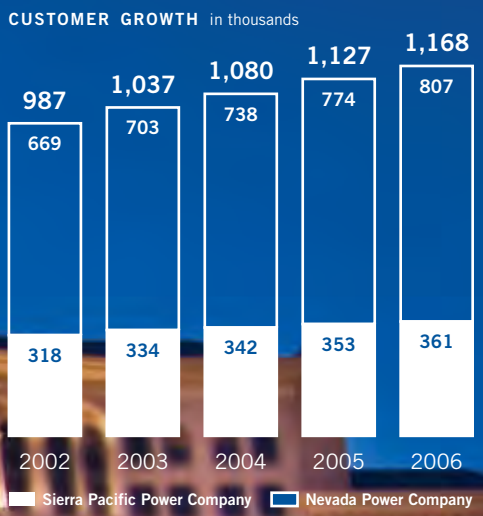
to be the best utility company



ACHIEVING OUR VISION

The financial and operational achievements of Sierra Pacific Resources during 2006 amply demonstrate that the company is properly focused and well on its way to making our vision of being the best utility company for all of our constituencies a reality. The pages of this annual report discuss and illustrate the successes of the company and its utilities during the past year. We also hope it provides a glimpse into a bright future.

Pictured on Cover: James Contreras is a journeyman lineman at Nevada Power Company.



for our customers

RAPID GROWTH CONTINUES

Nevada has been the nation's fastest-growing state for nearly two decades and Sierra Pacific Resources and its utilities have successfully met the challenges of serving this unprecedented growth. Massive new resort projects in southern Nevada and the huge influx of other new businesses and residents throughout the state make it clear that meeting the needs of a burgeoning customer base will continue for years to come.

Las Vegas native Dana Galtney deals blackjack at the Bellagio hotel and casino.

Sierra Pacific

for our employees

INVESTING IN GENERATION

For many years, the state of Nevada has been largely dependent on costly and volatile out-of-state sources for its energy needs. Nevada Power Company has doubled its generating capacity over the past two years with the addition of new, highly efficient natural gas-fired power plants. In northern Nevada, Sierra Pacific Power Company is adding 514 megawatts of gas-fired generation at its Tracy Generating Station, shown here under construction. In eastern Nevada, the planned Ely Energy Center will initially provide 1,500 megawatts of clean, coal-fired electricity for customers of both utilities.

Instrument Technician Mundo Fabbi helps keep the turbines spinning at the Tracy Generating Station near Reno.

WINDSTOPPER

for our communities

ADDING RENEWABLE ENERGY

The addition of renewable energy sources to the supply portfolios at both Nevada Power and Sierra Pacific Power is a top priority of both utilities. Upon completion in 2007, the 64-megawatt SolarOne project in southern Nevada, shown here, will be one of the largest solar power plants in the world and its entire output will be sold to our company. In northern Nevada, we currently receive geothermal energy from 14 plants and have active plans to add even more. Solar, geothermal and wind power projects, in addition to an aggressive package of energy conservation programs, are all included in our quest to better serve the communities in which we do business.

Kelly Johnson, an associate engineer with the Resource Planning Department, stands by an array of mirrors at the new SolarOne plant near Las Vegas.

for our shareholders

FINANCIAL HIGHLIGHTS

(dollars in thousands, except per share information)	2006	2005
Total Operating Revenues	$ 3,355,950	$ 3,030,242
Total Operating Expenses	$ 2,867,153	$ 2,671,564
Net Income Applicable to Common Stock	$ 277.451	$ 82,237
Net Income Applicable to Common Stock—basic	$ 1.33	$ 0.44
Weighted Average Common Shares—basic	208,531,134	185,548,314
Total Assets	$ 8,832,076	$ 7,870,546
Total Electric Retail Sales (Megawatt Hours)	29,530,239	28,688,600
Total Retail Gas Sales (Decatherms)	15,058,000	14,819,000
Total Electric Customers	1,168,000	1,127,000
Total Gas Customers	146,000	140,000

Beautiful Lake Tahoe is one of the areas served by Sierra Pacific Power.

Walter M. Higgins
Chairman and Chief Executive Officer

TO OUR SHAREHOLDERS:

Most every company aspires to be the best in its industry. While this is never easily attained, it is indisputable that a key ingredient to achieving this objective is to set challenging goals. At Sierra Pacific Resources we truly have the potential to be the best utility company for our customers, our communities, our investors and our employees, and we made further strides toward realizing that vision during the past year.

In this letter, I will share with you the major accomplishments of 2006 and the plans we are implementing to realize our strategic goals. We believe Sierra Pacific Resources and its utilities are well on their way to becoming the *best* in our field.

The fine work of the employees at our utilities, Nevada Power Company and Sierra Pacific Power Company, produced strong financial and operational results in 2006. These accomplishments were due to a business strategy that emphasizes our core businesses—providing electricity and natural gas to over one million customers in one of the fastest-growing states in the nation.

What were some of the key achievements during the year?

- Consolidated earnings for 2006 were $277.5 million, or $1.33 per share, compared with $82.2 million, or 44 cents per share, in 2005.
- We completed financings for more than $2 billion in debt, extended debt maturities, lowered interest rates and increased liquidity for our utilities.
- Our stock value continued to grow. Sierra Pacific Resources' stock price began the year at $13.12 per share and ended 2006 at $16.83. This marked the third consecutive year of outperforming the utility indices.
- Credit ratings for the senior secured debt of our utilities were upgraded to investment grade status by Fitch Investor's Service; and Standard & Poor's upgraded its ratings to a single step below investment grade.
- We more than doubled our generating capacity in southern Nevada with the addition of three natural gas-fired generating plants and obtained approval from state utility regulators to move forward with the first phase of the proposed clean-coal-fired Ely Energy Center, as well as some much-needed new peaking plants in southern Nevada.
- New supplies of renewable geothermal power were added to our energy portfolio, and our customers will soon be getting electricity from a new solar thermal plant nearing completion in southern Nevada. A department solely dedicated to renewable energy was established.

THE FINANCIAL PICTURE

Your company's fundamental financial goals remain the same as those that we've been striving for ever since the difficult years following the Western Energy Crisis of 2000–2001: increasing shareholder value, achieving investment grade status, and restoring shareholder dividends.

While strong customer growth and operational improvements positively affected financial results, consolidated earnings for Sierra Pacific Resources were also bolstered by a Nevada Supreme Court decision to reverse a previous regulatory disallowance and by the sale of our ownership interest in the Tuscarora Gas Pipeline.

In July 2006, the Nevada Supreme Court ruled that Nevada Power should recover $180 million in energy costs that were disallowed by state utility regulators in 2002. In February 2007, we reached an agreement with the Public Utilities Commission of Nevada staff, the Nevada Attorney General's Bureau of Consumer Protection and others on how to recover these costs, as well as certain carrying costs, over a 10-year period, in order to lessen the impact on Nevada Power's customers. The PUCN approved this agreement in March 2007.

In December 2006, we completed the sale of Sierra Pacific Resources' 50 percent interest in the Tuscarora Gas Transmission Company to TC PipeLines, LP, a subsidiary of TransCanada Corporation, for approximately $100 million.

FINANCIAL RESULTS AT NEVADA POWER AND SIERRA PACIFIC POWER

For 2006, Nevada Power Company's net income was $224.5 million, compared with $132.7 million for 2005. This improvement was primarily due to the Nevada Supreme Court decision described above, but was also due to continued customer growth in Las Vegas.

In the spring of 2006, the PUCN approved settlements granting Nevada Power full recovery of $171.5 million in past fuel and purchased power expenses, as well as an increase in rates of $120 million reflecting higher forecasted energy costs.

Hearings are scheduled in the spring of 2007 for a general rate case filed by Nevada Power that requests an electric revenue increase of $156.4 million and seeks to have the return on equity set at 11.4 percent. These increases are largely to cover the addition of new power plants to our rate base.

Net income for Sierra Pacific Power in 2006 was $57.7 million, compared with $52.1 million in 2005. Continued customer growth was the main contributor to the increase.

In the spring of 2006, the PUCN approved settlements granting Sierra Pacific Power full recovery of $46.7 million in past energy expenses, as well as an increase in rates of $30.9 million reflecting higher forecasted energy costs. State regulators also reset rates to reflect a $9.5 million net decrease in general rates for electricity and natural gas customers.

Pending rate cases for both utilities related to fuel and purchased power costs should result in slight rate decreases for electric customers.

NEVADA'S STRONG GROWTH CONTINUES

We are continuing to enjoy robust customer growth because of Nevada's dynamic economy. Nevada Power field crews installed 44,103 electric meters in 2006 and Sierra Pacific Power employees installed 9,950 electric meters and a record 5,991 natural gas meters.

Nevada's population is expected to double over the next 20 years. Although northern Nevada has a healthy, diverse economy, Nevada's strongest growth continues to be in southern Nevada.

Las Vegas is adding thousands of hotel rooms over the next few years. Construction is under way on the MGM Mirage's $7 billion CityCenter project, and construction is expected to start during 2007 on Boyd Gaming Corporation's $4 billion development, Echelon Place. Both projects will create thousands of jobs.

Peak demand for electricity in Nevada Power's service territory is expected to increase by approximately 250 megawatts annually through 2010, while peak demand for electricity in Sierra Pacific Power's service area is expected to grow by about 40 megawatts per year during the same period.

Nevada Power's customers set an all-time electric demand peak of 5,623 megawatts on July 17, 2006, and the electric peak at Sierra Pacific Power reached 1,701 megawatts on July 25, 2006.

Sierra Pacific Power's natural gas customers in the Reno-Sparks area set an all-time peak for natural gas consumption of 136.8 million cubic feet for a 24-hour period in December 2006.

GENERATING MORE POWER IN NEVADA

Quite likely our company's greatest challenge—as well as opportunity—is to ensure adequate energy supplies are available to serve our company's ever-growing customer base. We are making significant progress toward our goal of increasing company-owned generation and reducing our dependence on volatile wholesale energy markets.

Nevada Power began commercial operation of the 1,200-megawatt, gas-fired Chuck Lenzie Generating Station in 2006 and acquired a 75 percent interest in the 560-megawatt, gas-fired Silverhawk Generating Station. In addition, Nevada Power added an 84-megawatt, combustion turbine peaking unit at the Harry Allen Generating Station.

Nevada Power has received regulatory approval to construct additional gas-fired peaking units at Clark Station that will produce over 600 megawatts. The first 413-megawatt unit is scheduled for completion by the summer of 2008, and the remaining 206-megawatt unit should be on line in 2009.

Construction is well underway in northern Nevada on the 514-megawatt Tracy Combined Cycle Plant near Reno. Similar to Nevada Power's newest plants, this plant will be highly efficient, produce fewer emissions and require significantly less water than more conventional gas-fired plants. The facility is expected to be completed by the summer of 2008.

Our company's long-term goal is to have the right energy supply, a diverse mix of energy supplies, including power plants fueled by natural gas and coal, as well as renewable energy and energy conservation. The proposed Ely Energy Center in eastern Nevada will be a vital part of this supply portfolio, and power from this project will serve customers of both our utilities.

Located near the community of Ely, the project's first phase, expected to cost $3.8 billion, includes two 750-megawatt units that will incorporate the latest fully-environmentally compliant, clean, supercritical pulverized coal technologies. The plant will be fueled with cleaner-burning, low sulfur coal from the Powder River Basin. Because coal is the most economical fuel source available, this facility will help hold down costs and improve reliability for our customers.

The company's goal is to build the cleanest, most environmentally friendly coal-fired generating plant in the West. The energy produced by this plant will replace the output from older coal-fired generating units at Nevada Power that will be retired from service in the future, as well as power from aging natural gas-fired units at Clark Station decommissioned in 2006.

The first unit at Ely should be completed in late 2011 with the second unit coming on line in 2013. We are also closely following the development of coal gasification technology—a process for reducing emissions. Once it has been clearly established that this technology is commercially viable for Western coal, we expect to add 1,000 megawatts at the Ely site fueled by gasified coal.

Additionally, the Ely project will include a 500-kilovolt transmission line extending for 250 miles from Ely to Las Vegas, which will provide the first electrical interconnection between Nevada Power and Sierra Pacific Power. Approximately 300 megawatts of capacity on the new transmission line will be reserved for renewable energy, making it possible to move renewable energy supplies throughout the state. The line will also be used to transport power from wind generation facilities proposed for eastern Nevada.

AN ABUNDANCE OF RENEWABLE ENERGY

Nevada is rich in renewable resources, and non-polluting renewable energy is playing an increasingly important role at our company as we endeavor to make the best use of this potential and to comply with Nevada's progressive renewable energy portfolio standard. Nevada's law requires that 20 percent of the total energy sales at our utilities must be from renewable resources by 2015, with 1 percent of total energy sales from solar energy.

We currently purchase renewable energy from 14 geothermal power plants in northern Nevada, and the PUCN has approved contracts for an additional 73 megawatts of geothermal energy from plants expected to begin operations in 2010.

In 2007, the SolarOne project south of Las Vegas is expected to come on line. This 64-megawatt, thermal solar generating plant, owned primarily by Acciona Solar, is the largest solar project to be constructed in the U.S. during the past 15 years, and the entire output of SolarOne will be sold to our utilities.

Once this project is completed, along with another 10-megawatt photovoltaic power plant proposed near Las Vegas, Nevada will be the number one state in the nation for solar energy on a per capita basis.

Up to 25 percent of Nevada's renewables portfolio standard can be fulfilled with energy efficiency programs. In 2006, energy efficiency programs for residential and commercial customers at the two utilities reduced energy use by nearly 223 million kilowatt hours.

EMPLOYEES ACHIEVING THEIR FULL POTENTIAL

As the cover of this report suggests, our employees are driven to excel and we take enormous pride in their achievements. Due to their efforts, electric reliability rates at Nevada Power and Sierra Pacific Power are among the best in the U.S. In addition, many of our generating units are top performers, and our goal is to ensure our entire generating fleet is in the top quartile for unit availability within five years.

We're also strengthening our electric transmission system. In March 2007, Nevada Power energized the final 48-mile leg of the Centennial Project, which consists of 176 miles of new transmission lines to serve southern Nevada.

Although our employees are performing at a high level, it is always possible to find better ways to carry out our mission. In 2006, we began a company-wide process improvement initiative. The goal of this initiative is to put the company in the upper quartile of the electric utility industry for employee satisfaction and labor productivity, reputation, operating metrics and total return to shareholders.

We also are making steady progress with our Diversity Champions initiative, an intensive training program to teach all our employees about diversity and the value it can bring to our company. We're trying hard to ensure that our workforce reflects the diversity found in the communities we serve and to ensure diversity is respected and supported throughout our organization. Our Diversity Champions program has been the best received training we have ever offered to our employees.

IN THE COMMUNITY

Because our company can only be as strong as the communities we serve, we actively support local economic development activities and we invest in the state's future through extensive philanthropic giving and volunteer programs. During 2006, our company gave $2.2 million in charitable support, with major focus on education, nonprofit community service organizations, civic and youth groups, and the arts. Company-wide, our employees volunteered approximately 22,000 hours to community activities.

ORGANIZATIONAL ENHANCEMENTS

Early this year, we announced some organizational changes that position us even more strongly for the future. Brian J. Kennedy, former president and chief executive officer of Reno-based Meridian Gold, Inc., a mining company, has been elected to our company's Board of Directors. Brian, who since his retirement in 2006, has continued as Meridian's chairman, brings a broad range of management and financial experience to our company. He also has been a distinguished community and professional leader for several years, and has a full understanding of our rapidly growing state, including the businesses and communities we serve.

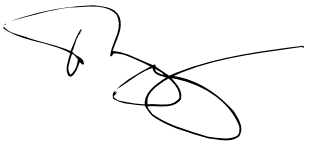
In addition, Michael W. Yackira has been elected to serve as president and chief operating officer and as a member of the company's Board of Directors. Michael, who had served as the company's chief financial officer since December 2003, is succeeded in that role by William D. Rogers, who is now the company's corporate senior vice president, chief financial officer and treasurer. Bill has been the company's treasurer since June of 2005.

Michael's drive and expertise have proven invaluable as our company has recovered from the difficulties caused by the Western Energy Crisis, and both Michael and Bill have worked successfully to strengthen the company financially and raise capital necessary for our rapid growth.

At the beginning of this letter, I mentioned that those who aspire to become the best in their industry must establish challenging goals. We believe Sierra Pacific Resources is already on a positive course and we have laid the groundwork for continuing progress by focusing on five strategic goals for the next five years.

- **Employees who make a big difference**—further developing engaged, diverse, accountable and high performing people.
- **A great reputation**—always meeting our commitments in both operational and financial performance as well as being a good corporate citizen in every community in which we do business.
- **Operate and serve well**—assuring good, safe and reliable service to all customers.
- **The right energy supply**—creating a portfolio approach which balances costs to customers, supply reliability, fuel and power market volatility and environmental acceptability.
- **An industry leading investment**—placing Sierra Pacific Resources among the best in our industry, based on a five-year total shareholder return.

In closing, on behalf of the Board of Directors, I'd like to thank you, our shareholders, for your continuing support. While everyone at Sierra Pacific Resources is driven by a desire to make this a stronger, better performing company, that would be impossible without your backing. For that, we are profoundly grateful.



Walter M. Higgins
Chairman and Chief Executive Officer

March 26, 2007

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Board of Directors & Senior Officers
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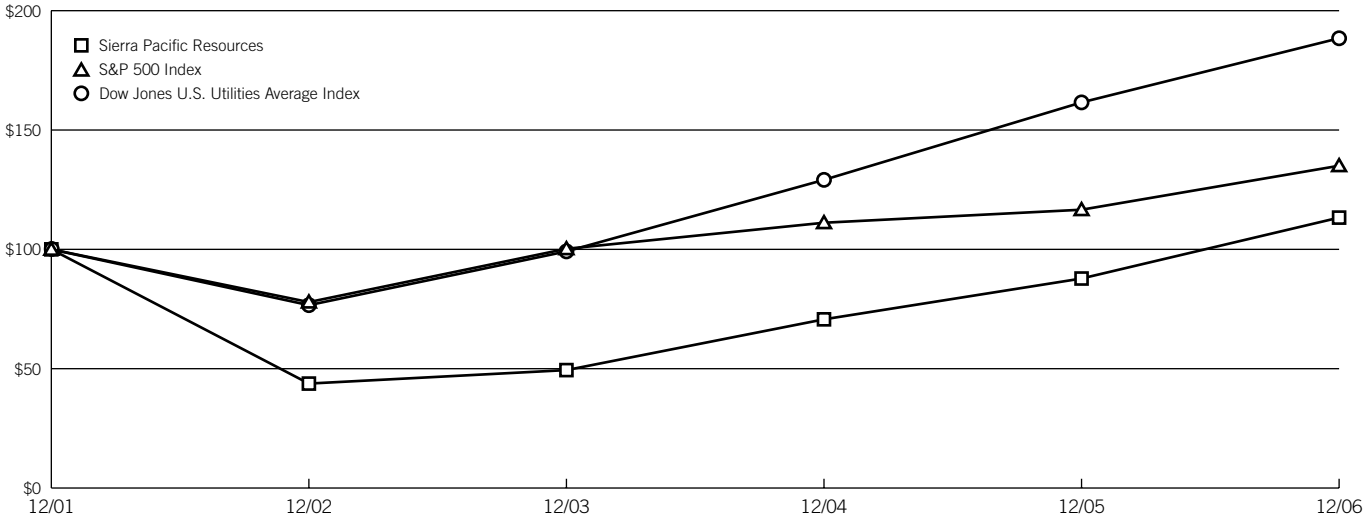
COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURN*

Among Sierra Pacific Resources, the S&P 500 Index and the Dow Jones U.S. Utilities Average Index



**$100 invested on 12/31/01 in stock or index—including reinvestment of dividends. Fiscal year ending December 31.*

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 SPR, NPC and SPPC.

Year ended December 31,	**2006[1]**	2005[2]	2004[3]	2003[4]	2002[5]
(dollars in thousands; except per share amounts)					
Operating Revenues	**$3,355,950**	$3,030,242	$2,824,796	$2,787,543	$2,984,604
Operating Income (Loss)	**$ 488,797**	$ 358,678	$ 333,858	$ 260,314	$ (28,939)
Income (Loss) from Continuing Operations	**$ 279,792**	$ 86,137	$ 30,842	$ (117,286)	$ (297,733)
Income (Loss) from Continuing Operations Per Average Common Share—Basic and Diluted	**$ 1.34**	$ 0.46	$ 0.17	$ (1.01)	$ (2.92)
Total Assets	**$8,832,076**	$7,870,546	$7,528,467	$7,063,758	$7,110,639
Long-Term Debt	**$4,001,542**	$3,817,122	$4,081,281	$3,579,674	$3,194,966
Dividends Declared Per Common Share	**$ —**	$ —	$ —	$ —	$ 0.20

(1) Income from continuing operations for the year ended December 31, 2006 includes reinstatement of deferred energy of approximately $180 million and a $62.9 million gain on the sale of Tuscarora Gas Pipeline Company's partnership interest in Tuscarora Gas Transmission Company.

(2) Income from continuing operations for the year ended December 31, 2005 includes a charge of $54 million for the inducement of debt conversion and the reversal of $20.9 million in interest charges as a result of settlements with terminated suppliers.

(3) Income from continuing operations for the year ended December 31, 2004 includes the reversal of $39.8 million in interest expense due to the decision on the appeal of the Enron bankruptcy judgment and the write-off of $47.1 million in disallowed plant costs at SPPC.

(4) Loss from continuing operations for the year ended December 31, 2003 was negatively affected by an unrealized net loss of $46.1 million on the derivative instrument associated with the issuance of SPR's $300 million Convertible Notes, $91 million write-off of deferred energy costs by NPC and SPPC and approximately $52 million of interest charges related to the Enron litigation.

(5) Loss from continuing operations and total assets for the year ended December 31, 2002 was severely affected by the write-off of deferred energy costs and related carrying charges of $523 million as a result of the PUCN decision in NPC's and SPPC's deferred energy cases disallowing $434 million and $53 million, respectively, of deferred purchased fuel and power costs.

NEVADA POWER

Year ended December 31,	**2006[1]**	2005[2]	2004[3]	2003[4]	2002[5]
(dollars in thousands)					
Operating Revenues	**$2,124,081**	$1,883,267	$1,784,092	$1,756,146	$1,901,034
Operating Income (Loss)	**$ 351,272**	$ 228,827	$ 216,490	$ 183,733	$ (104,003)
Net Income (Loss)	**$ 224,540**	$ 132,734	$ 104,312	$ 19,277	$ (235,070)
Total Assets	**$5,987,515**	$5,173,921	$4,883,540	$4,210,759	$4,166,988
Long-Term Debt	**$2,380,139**	$2,214,063	$2,275,690	$1,899,709	$1,683,310
Dividends Declared—Common Stock	**$ 48,917**	$ 35,258	$ 45,373	$ —	$ 10,000

(1) Income from continuing operations for the year ended December 31, 2006 includes reinstatement of deferred energy of approximately $180 million.

(2) For the year ended 2005 Income from Continuing Operations included the reversal of $17.7 million in interest charges as a result of settlements with terminated suppliers.

(3) Net Income for the year ended December 31, 2004 included the reversal of $27.5 million in interest expense due to the decision on the appeal of the Enron bankruptcy judgment.

(4) Net Income for the year ended December 31, 2003 included a $46 million write-off of deferred energy costs and $36 million of interest charges related to the Enron litigation.

(5) Net Loss and Total Assets for the year ended December 31, 2002 was severely affected by the write-off of $465 million of deferred purchased fuel and power costs and related carrying charges.

SIERRA PACIFIC POWER

Year ended December 31,	**2006**	2005[1]	2004[2]	2003[3]	2002[4]
(dollars in thousands)					
Operating Revenues	**$1,230,230**	$1,145,697	$1,035,660	$1,029,866	$1,081,034
Operating Income	**$ 120,017**	$ 116,304	$ 111,245	$ 68,566	$ 55,292
Net Income (Loss)	**$ 57,709**	$ 52,074	$ 18,577	$ (23,275)	$ (13,968)
Total Assets	**$2,807,837**	$2,546,301	$2,524,320	$2,362,469	$2,457,516
Preferred Stock	**$ —**	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Long-Term Debt	**$1,070,858**	$ 941,804	$ 994,309	$ 912,800	$ 914,788
Dividends Declared—Common Stock	**$ 24,619**	$ 23,933	$ —	$ 18,530	$ 44,900
Dividends Declared—Preferred Stock	**$ 975**	$ 3,900	$ 3,900	$ 3,900	$ 3,900

(1) Income from Continuing Operations, for the year ended December 31, 2005 includes the reversal in the fourth quarter of $3.2 million in interest expense related to settlement with terminated suppliers.

(2) Net Income from Continuing Operations, for the year ended December 31, 2004 was affected by the write-off of $47.1 million in disallowed plant costs and the reversal of interest expense of $12.3 million due to the decision on the appeal of the Enron Bankruptcy judgment and a reduction to income tax expense of $3.3 million as a result of a flow-through adjustment for pension funding.

(3) Loss from Continuing Operations, for the year ended December 31, 2003 was affected by the write-off of $45 million in June 2003 of disallowed deferred energy costs and interest charges of $16 million related to the Enron litigation.

(4) Loss from Continuing Operations, for the year ended December 31, 2002 was severely affected by the write-off of $58 million of deferred purchased fuel and power costs and related carrying charges.

FORWARD-LOOKING STATEMENTS

The information in this Form 10-K 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 Sierra Pacific Resources (SPR), Nevada Power Company (NPC) or Sierra Pacific Power Company (SPPC) to differ materially from those contemplated in any forward-looking statement include, among others, the following:

(1) unfavorable or untimely rulings in rate cases filed or to be filed by NPC and SPPC (collectively referred to as the Utilities) with the Public Utility 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 costs recorded by SPPC for its gas distribution business;

(2) the ability and terms upon which SPR, NPC and SPPC will be able to access the capital markets to support their requirements for working capital, including amounts necessary for construction and acquisition costs and other capital expenditures, as well as to finance deferred energy costs, particularly in the event of unfavorable rulings by the PUCN, untimely regulatory approval for such financings and/or a downgrade of the current debt ratings of SPR, NPC or SPPC;

(3) whether the Utilities will be able to continue to obtain fuel and power from their suppliers on favorable payment terms and favorable prices, particularly in the event of unanticipated power demands (for example, due to unseasonably hot weather), sharp increases in the prices for fuel and/or power or a ratings downgrade;

(4) changes in environmental laws or regulations, including the imposition of significant new limits on emissions from electric generating facilities, such as requirements to reduce carbon dioxide (CO2) emissions, other greenhouse gases and/or other pollutants in response to climate change legislation;

(5) 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;

(6) changes in the rate of industrial, commercial and residential growth in the service territories of the Utilities;

(7) the effect that any construction risks may have on our business, such as the risk of delays in permitting, changes in environmental laws, securing adequate skilled labor, cost and availability of materials and equipment, equipment failure, work accidents, fire or explosions, business interruptions, possible cost overruns, delay of in-service dates and pollution and environmental damage;

(8) whether the Utilities can procure sufficient renewable energy sources in each compliance year to satisfy the Nevada Portfolio Standard;

(9) whether NPC will be successful in obtaining PUCN approval to recover the outstanding balance of its other regulatory assets and other merger costs recorded in connection with the 1999 merger between SPR and NPC in a future general rate case;

(10) whether the Utilities will be able to continue to pay SPR dividends under the terms of their respective financing and credit agreements, their regulatory order from the PUCN and limitations imposed by the Federal Power Act;

(11) unseasonable weather and other natural phenomena, which, in addition to affecting the Utilities' customers' demand for power, can have a potentially serious impact 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;

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

(13) the final outcome of the proceedings to reverse the PUCN's 2004 decision on SPPC's 2003 General Rate Case, which disallowed the recovery of a portion of SPPC's costs, expenses and investment in the Piñon Pine Project;

(14) the timing of the PUCN's decision regarding the time period NPC is to recover the approximate $180 million of deferred energy that were disallowed in 2002 and were reinstated by the Nevada Supreme Court in July 2006;

(15) the timing and final outcome of the PUCN's decision regarding the Utilities' recovery of deferred energy costs associated with claims for terminated supplier contracts;

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

(17) changes in tax or accounting matters or other laws and regulations to which SPR or the Utilities are subject;

(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 or power demands of the Utilities' 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) unusual or unanticipated changes in normal business operations, including unusual maintenance or repairs;

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

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

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.

EXECUTIVE OVERVIEW

Management's Discussion and Analysis of Financial Condition and Results of Operations explains the general financial condition and the results of operations of Sierra Pacific Resources (SPR) and its two primary subsidiaries, Nevada Power Company (NPC) and Sierra Pacific Power Company (SPPC), collectively referred to as the "Utilities" (references to "we," "us" and "our" refer to SPR and the Utilities collectively), and includes the following:

- Critical Accounting Policies and Estimates
    - Recent Pronouncements
- For each of SPR, NPC and SPPC:
    - Results of Operations
    - Analysis of Cash Flows
    - Liquidity and Capital Resources
    - Energy Supply (Utilities)
    - Regulatory Proceedings (Utilities)

SPR's Utilities operate three regulated business segments which are NPC electric, SPPC electric and SPPC natural gas. The Utilities are public utilities engaged in the distribution, transmission, generation and sale of electricity and, in the case of SPPC, sale of natural gas. Other segment operations consist mainly of unregulated operations and the holding company operations. The Utilities are the principal operating subsidiaries of SPR and account for substantially all of SPR's assets and revenues. SPR, NPC and SPPC are separate filers for SEC reporting purposes and as such this discussion has been divided to reflect the individual filers (SPR, NPC and SPPC), except for discussions that relate to all three entities or the Utilities.

The Utilities are regulated by the PUCN and, for the California service territory of SPPC, the California Public Utilities Commission (CPUC), with respect to rates, standards of service, setting of and necessity for generation and certain transmission facilities, accounting, issuance of securities and other matters with respect to generation, distribution and transmission operations. Under federal law, wholesale rates charged by the Utilities 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.

The Utilities' revenues and operating income are subject to fluctuations during the year due to the impacts of seasonal weather, rate changes and customer usage patterns have on demand for electric energy and services. NPC is a summer peaking utility experiencing its highest retail energy sales in response to the demand for air conditioning. SPPC's electric system peak typically occurs in the summer, with a slightly higher peak demand in the winter.

Overview of Major Factors Affecting Results of Operations

During 2006, SPR's net income applicable to common stock was $277.5 million compared to $82.2 million in 2005. The change in earnings was primarily due to the following items (after income taxes):

- the July 2006 Nevada Supreme Court ruling which allows NPC to recover approximately $180 million ($117 million after tax) of the previously disallowed deferred energy costs, for further discussion of the legal proceeding, see Note 13, Commitments and Contingencies, of the Notes to Financial Statements;
- the $40.9 million gain on sale of the partnership interest in Tuscarora Gas Transmission Company (TGTC) held by Tuscarora Gas Pipeline Company's (TGPC), a wholly-owned subsidiary of SPR;
- improved operating income (excluding the approximate $180 million reinstatement);
- other income of $21.7 million for the carrying charge on Lenzie;
- early tender fees of $6.9 million for the extinguishment of $85 million of SPR's 8.625% Senior Notes and $25 million of SPR's 7.803% Senior Notes; and
- a charge recorded in 2005 for $35.1 million in early debt conversion fees associated with SPR's Convertible Notes.

During 2005, SPR's net income applicable to common stock was $82.2 million compared to $28.6 million in 2004. The change in earnings was primarily due to the following items (after income taxes):

- increases in operating income primarily resulting from general rate cases decided in 2004 as well as continued customer growth;
- increases in Allowance for Other Funds used During Construction and Allowance for Borrowed Funds used During Construction, for a total of approximately $29.3 million, primarily due to the construction of the Chuck Lenzie Generating Station;
- lower interest expenses due to refinancing activities;
- reversal of interest for energy suppliers on settled disputes of approximately $13.6 million.

Partially offsetting these increases in net income applicable to common stock were the following items (after income taxes):

- early conversion fees of the Convertible Notes of approximately $35.1 million after taxes and unamortized debt issuance costs and legal fees associated with the various financing transactions of approximately $6.3 million after taxes;
- legal fees of approximately $7.4 million.

Overview of Key Business Issues

During 2006, SPR continued to focus on a "back to the basics" strategy that emphasized the Utilities' core business. SPR's and the Utilities' strategies were aimed at owning more generating facilities, thereby reducing dependence on purchased power, while at the same time diversifying fuel mix for the Utilities' growing service area. Looking ahead in 2007, SPR and the Utilities will continue to concentrate on the "back to the basics" strategy. The Utilities will continue to be subject to the purchased power and natural gas markets that have been volatile in recent years, in order to meet their obligations to serve their customers. Furthermore, with significant amounts of construction costs in the Utilities' future, SPR and the Utilities will need to raise substantial amounts of capital to fund expenditures. As a result, reducing the cost of capital by attaining investment grade ratings for the Utilities' secured debt has been and continues to be a significant business focus for 2007.

Summarized below are significant business issues in 2006 and the challenges ahead in 2007. It is not intended to be an exhaustive discussion, nor to suggest that other issues may not arise during 2007 or thereafter. Details relating to the discussion below can be found in the Notes to the Financial Statements and elsewhere within this Management's Discussion and Analysis of Financial Condition and Results of Operations.

GENERATION STRATEGY In 2003, NPC and SPPC embarked on a strategy to build or acquire electric power plants in order to reduce their exposure to the energy markets, in an effort to reduce prices and volatility for its customers and to provide an opportunity for increased earnings.

Accomplishments towards this goal in 2006 included:

- The completion of the Lenzie Generating Station, a nominally rated 1,200 MW natural gas-fired high efficiency combined-cycle power plant acquired from Duke Energy ("Lenzie").
- In January 2006, NPC completed the $208 million purchase of a 75 percent ownership interest in the Silverhawk Generating Facility ("Silverhawk") from Pinnacle West Capital Corporation ("Pinnacle West"), Pinnacle West Energy Corporation, a wholly-owned subsidiary of Pinnacle West, and GenWest, LLC. Silverhawk is a 560-megawatt, natural gas-fueled high efficiency combined-cycle electric generating facility located 20 miles northeast of Las Vegas.
- The completion of an 80 MW combustion turbine at NPC's Harry Allen site.

With the completion of Lenzie, and the additional unit at NPC's Harry Allen site, plus the acquisition of Silverhawk, NPC more than doubled its owned capacity since the end of 2005. As a result, NPC is less dependent upon the wholesale power markets for meeting the energy needs of its customers and produced approximately 54.3% of its energy needs in 2006 from owned generation, up from about 39% last year.

In addition, the PUCN granted NPC's request that Lenzie be designated a critical facility and allowed a 2% enhancement above NPC's authorized Return on Equity (ROE) to be applied to the rate base associated with the Lenzie construction costs expended after acquisition. The order allows for up to an additional 1%, or a total of 3% enhanced ROE, if the two Lenzie generator units were brought on line on or before dates specified in the order. In January 2006, NPC declared Block 1 of Lenzie commercially operable and in April 2006 declared Block 2 commercially operable, both ahead of the dates specified by the PUCN to qualify for the additional enhancement.

In 2006, SPPC began construction of a 514 MW gas-fired high efficiency combined-cycle generator at the Tracy Plant. SPPC anticipates an in-service date of June 2008. The PUCN also ordered that SPPC be allowed to include construction work in progress balances in the rate base of any interim general rate cases, prior to the in-service date, and granted a 1.5% enhanced ROE for the estimated $421 million investment. The unit will provide needed generation within SPPC's control area to reliably serve the growing needs of Northern Nevada.

LOOKING AHEAD In November 2006, the PUCN approved NPC's 2006 Integrated Resource Plan ("IRP") and SPPC's thirteenth amendment to its 2004 IRP. The Utilities' IRPs focus on conventional generation, renewable energy, conservation and transmission projects to meet Nevada's growing electricity needs while diversifying the fuel mix of the Utilities' generation portfolios. Included in the PUCN's approval is Phase 1 of the construction of the Ely Energy Center, a major project to be located near Ely, Nevada, consisting of two 750-megawatt coal-fired generation units. In addition, the PUCN approved the development and construction of a 250-mile 500kV transmission line that will deliver electricity from the Ely Energy Center as well as link NPC's and SPPC's transmission systems in the southern and northern portions of the state. The PUCN approved spending up to $300 million for development activities associated with the Ely Energy Center; however, they placed a $155 million spending limit until the appropriate air permits are obtained.

The PUCN established the project as a "critical facility," thereby allowing it to qualify for incentives that will be determined in a later filing. Additionally, the PUCN required NPC and SPPC to file amendments to their IRPs in early 2008 once elements of the plan, including final costs, can be more accurately estimated. The current estimate for the Ely Energy Center and the 500kV transmission line is approximately $3.8 billion.

The PUCN also approved for NPC the construction of 600 megawatts of natural gas-fired combustion turbine peaking units at Clark Station to be installed in 2008 and 2009 at an approximate cost of $395 million. In the case of SPPC, the PUCN approved upgrades to the combustion systems to Valmy Units 1 and 2. For more details of NPC's IRP and SPPC's thirteenth amendment, see Regulatory Proceedings, later.

Nevada law sets forth the renewable energy portfolio standard ("Portfolio Standard") requiring providers of electric service to acquire, generate or save a specific percentage of its energy from renewable energy resources (Renewables). Renewables include, but are not limited to: biomass, geothermal, solar and wind projects. In 2006, the Utilities were required to obtain six percent of their total energy from Renewables. The Portfolio Standard increases by three percent (3%) every other year until it reaches 20% in year 2015. In addition, the Portfolio Standard allows energy efficiency measures from qualified conservation programs to meet up to 25% of the Portfolio Standard. Moreover, not less than five percent (5%) of the total Portfolio Standard must be met from solar resources. In 2007 and 2008 the Utilities will be required to obtain nine percent (9%) of their total energy from Renewables. The Utilities have embarked on a strategy to invest in renewable energy that, along with third party contracts, will provide the opportunity for the Utilities to meet the Portfolio Standard as set forth by Nevada law.

MANAGEMENT OF ENERGY RISK The Utilities buy coal, natural gas and oil to operate generating plants as well as buy wholesale power to meet the energy requirements of their customers. The Utilities also have invested in and maintain extensive transmission systems that allow the Utilities to move energy to meet customers' needs. While NPC has greatly reduced its dependence on wholesale power markets to meet its customers' demand, both Utilities continue to have a significant need to tap energy markets due to the fact that the Utilities' owned generation is insufficient to meet their customers' energy needs. This situation exposes the Utilities to energy risk and uncertainty as to the Utilities' cash flow requirements for fuel and wholesale power, the expense the Utilities will incur as a result of their energy procurement efforts and the rates the Utilities need to recover those costs. Energy risk also encompasses reliability risk—the prospect that energy supplies will not be sufficient to fulfill customer requirements.

The Utilities systematically manage and control each of the energy-related risks through three primary vehicles—organization and governance, energy risk management programs and energy risk control practices.

The Utilities, through the purchases and sale of specified financial instruments and physical products, maintain an energy risk management program that limits energy risk to levels consistent with an approved energy supply plan. The energy risk management program provides for the systematic identification, quantification, evaluation and management of the energy risk inherent in the Utilities' operations.

The Utilities follow PUCN-approved energy supply plans that encompass the reliable and efficient operation of the Utilities' owned generation, the procurement of all fuels and purchased power and resource optimization. The process includes assessments of projected loads and resources, assessments of expected market prices, evaluations of relevant supply portfolio options available to the Utilities and evaluations of the risk attributable to those supply portfolio options. Financial instruments for economic hedging in conjunction with energy purchases and sales are also used to mitigate these risks.

LIQUIDITY AND ACCESS TO CAPITAL MARKETS With volatile energy costs and substantial commitments to construction, SPR and the Utilities' liquidity needs and access to capital markets was and continues to be a significant business issue. In 2006, management evaluated opportunities to refinance high yield debt at lower interest rates.

In 2006, SPR and the Utilities completed major financing transactions of approximately $1.6 billion that lowered our interest costs, improved liquidity and extended maturities, which include:

- issuance of $325 million of NPC's 6.5% General and Refunding Mortgage Notes, Series O, due 2018
- issuance of $370 million of NPC's 6.65% General and Refunding Mortgage Notes, Series N, due 2036
- issuance of $210 million of NPC's 5.95% General and Refunding Mortgage Notes, Series M, due 2016
- issuance of $92.5 million of various NPC Pollution Control Refunding Revenue Bonds
- increases to NPC's and SPPC's Revolving Credit facilities to $600 million and $350 million, respectively
- issuance of $300 million of SPPC's 6.0% General and Refunding Mortgage Notes, Series M, due 2016
- issuance of $268 million of SPPC's Pollution Control and Gas and Water Facilities Refunding Revenue Bonds, Series 2006, 2006A, 2006B and 2006C
- SPR tendered for and extinguished approximately $85 million of SPR's 8.625% Senior Notes and approximately $25 million of SPR's 7.803% Senior Notes
- redemptions of various NPC debt of approximately $667.8 million
- redemption and payments of various SPPC debt of approximately $487 million
- redemption of $50 million of SPPC's Series A Preferred Stock

In August 2006, SPR issued 20 million shares of its $1 par value common stock. Net proceeds from the issuance were $280.6 million. In August 2006, SPR made a capital contribution to NPC for approximately $200 million. On December 27, 2006, SPR contributed capital to SPPC of approximately $75 million. SPR has invested the remaining proceeds in highly liquid short-term investments pending their use for general corporate purposes. As of December 31, 2006, SPR has 350 million shares of common stock authorized and approximately 221 million shares of common stock issued and outstanding.

LOOKING AHEAD Management has been and continues to be focused on returning the Utilities' senior secured debt to investment grade credit quality. Significant amounts of capital may be necessary to fund the construction costs of new power plants and, as a result, management may be required to meet such financial obligation with a combination of internally generated funds, the use of the Utilities' revolving credit facilities, the issuance of long-term debt, and, if necessary, capital contributions from SPR. If energy costs rise at a rapid rate and the Utilities do not recover, in a timely manner, the cost of fuel and purchased power, the Utilities may need to issue more debt to support their operating costs or may need to delay capital expenditures.

REGULATORY As is the case with most regulated entities, the Utilities are frequently involved in various regulatory proceedings. The Utilities are required to file for annual rate adjustments to provide recovery of their fuel and purchased power costs. They are also required to file rate cases every two years to adjust general rates that include their cost of service and return on investment in order to more closely align earned returns with those allowed by regulators. In addition, as necessary, the Utilities can file for a change to their Base Tariff Energy Rates (BTER) to more closely match actual prices. The Utilities remain committed to maintaining a positive relationship with their regulators. Details regarding recently approved and pending rate cases are discussed below in Regulatory Proceedings.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

SPR prepared its consolidated financial statements in accordance with accounting principles generally accepted in the United States of America. In doing so, certain estimates were made that were critical in nature to the results of operations. The following discusses those significant estimates that may have a material impact on the financial results of SPR and the Utilities and are subject to the greatest amount of subjectivity. Senior management has discussed the development and selection of these critical accounting policies with the Audit Committee of SPR's Board of Directors. The items discussed below represent critical accounting estimates that under different conditions or using different assumptions could have a material effect on the financial condition, results of operation, cash flows, liquidity and capital resources of SPR and the Utilities.

Regulatory Accounting

The Utilities' retail rates are currently subject to the approval of the PUCN and, in the case of SPPC, they are also subject to the 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. Under federal law, wholesale rates charged by the Utilities 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.

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, Summary of Significant Accounting Policies, of the Notes to Financial Statements, management believes the existing regulatory assets are probable of recovery. Management's judgment 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 and expensed in current period earnings.

Regulatory Accounting affects other Critical Accounting Policies, including Deferred Energy Accounting, Accounting for Pensions, and Accounting for Derivatives and Hedging Activities, all of which are discussed immediately below.

DEFERRED ENERGY ACCOUNTING Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates, the 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 approval. Pursuant to AB 369, Nevada law 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, Nevada law specifies that fuel and purchased power costs include all costs incurred to purchase fuel, to purchase capacity, and to purchase energy. Both Utilities are entitled under statute to utilize deferred energy accounting for their electric operations and both Utilities accumulate amounts in their deferral of energy costs accounts. The Utilities also record, and are eligible under the statute to recover, a carrying charge on such deferred balances, recognized as interest income in the current period.

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 Item 7A, Quantitative and Qualitative Disclosures About Market Risk, for a discussion of the Utilities' purchased power procurement strategies, and commodity price risk and commodity risk management program. Currently, commodity price increases are recoverable through the deferred energy accounting mechanism, with no anticipated effect on earnings. 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.

See Note 3, Regulatory Actions, of the Notes to Financial Statements for additional discussion of the regulatory process to recover these deferred costs and description of the PUCN's disallowance of significant amounts in NPC's 2001 deferred energy cases.

Accounting for Derivatives and Hedging Activities

SPR, NPC and SPPC apply SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. SFAS No. 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. The accounting for derivatives depends on the intended use of the derivatives and the resulting designation.

FUEL AND PURCHASED POWER CONTRACTS In order to manage loads, resources and energy price risk, the Utilities enter into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. In addition to forward fuel and power contracts, the Utilities also use over-the-counter options with financial institutions and other energy companies to manage price risk. All of these instruments are considered to be derivatives under SFAS No. 133 and are marked to market in the statement of financial position unless the contract qualifies for the normal purchases or sales exemption per the criteria in 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 options and these forward fuel and power contracts and other energy-related derivative instruments.

In conjunction with the issuance of SFAS No. 133, the Public Utilities Commission of Nevada (PUCN) and, in the case of SPPC, the California Public Utility Commission (CPUC), issued accounting orders authorizing the Utilities to offset any derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark to market gains and losses on energy commodity transactions until the period of settlement. The order provides for the Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the statement of operations and comprehensive income. Fuel and purchased power costs are subject to this accounting order and apply deferred energy accounting. Upon settlement of a derivative instrument, actual fuel and purchased power costs are recognized in the period of settlement if currently recoverable or deferred if they are recoverable or payable through future rates.

The fair values of the forward contracts are determined based on quotes obtained from independent brokers and exchanges. The fair values of options are determined using a pricing model that 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. The fair value of the Utilities derivative commodity instruments, which are recorded on the Consolidated Balance Sheet, are sensitive to market price fluctuations that can occur on a daily basis.

Accounting for Income Taxes

As of December 31, 2006, net operating losses (NOLs) were $227.1 million. The NOLs may be utilized in future periods to reduce taxes payable to the extent that SPR and the Utilities recognize taxable income.

The following table summarizes the NOL and tax credit carry-forwards and associated carry-forward periods, and a valuation allowance for amounts which SPR has determined that realization is uncertain (dollars in thousands):

	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
Federal NOL	$213,024	$ —	$213,024	2020-2023
State NOL	1,058	—	1,058	2008-2013
Research and development credit	3,764	—	3,764	2021-2025
Alternative minimum tax credit	8,696	—	8,696	indefinite
Arizona state coal credits	1,292	732	560	2007-2011
Total	$227,834	$732	$227,102	

At December 31, 2006, the Utilities had gross federal and state NOL carryforwards of $608.6 million and $12.0 million, respectively.

Considering all positive and negative evidence regarding the utilization of the Utilities' deferred tax assets, it has been determined that the Utilities are more likely than not to realize all recorded deferred tax assets, except for the Arizona coal tax credits. As such, these Arizona coal tax credits represent the only valuation allowance that has been recorded as of December 31, 2006.

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 Department of Air Quality and Environmental Management (DAQEM) 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 clean up at any 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 clean up 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 13, Commitments and Contingencies, of the Notes to Financial Statements 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.

Defined Benefit Plans and Other Postretirement Plans

As further explained in Note 11, Retirement Plan and Postretirement Benefits, of the Notes to Financial Statements, SPR maintains a qualified pension plan, a nonqualified supplemental executive retirement plan (SERP) and restoration plan, as well as an other postretirement benefit (OPEB) plan that provides health and life insurance for retired employees. All employees are eligible for these benefits if they terminate with certain age and service requirements from the qualified and restoration plans, or if they reach retirement age and meet certain service requirements under the SERP and OPEB plans 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 are ultimately collected in rates billed to customers. Amounts are funded to trusts maintained for the plans. The amounts funded are then used to meet benefit payments to plan participants. SPR contributed $17.3 million and $17 million to its pension plan, in 2006 and 2005, respectively, and $8.6 million and $14.9 million to the other postretirement benefits plan in 2006 and 2005, respectively. At the present time it is not expected that any additional funding for the pension plan will be required for plan years 2006 or 2007 to meet the minimum funding levels defined by ERISA. However, SPR and the Utilities currently expect to contribute in 2007 an amount similar to the 2006 funding. The amounts to contribute may change subject to market conditions. SPR uses a September 30 measurement date for its benefit plans.

PENSION PLANS SPR's reported costs of providing non-contributory defined pension benefits (described in Note 11, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements) 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, the discount rates and demographic (mortality, retirement, termination) assumptions 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. SPR adopted SFAS 158 (see Note 1 of Notes to the Financial Statements, Recent Pronouncements) in 2006. This pronouncement requires the immediate recognition of changes in benefit obligations due to differences between actuarial assumptions and actual experience in Accumulated Other Comprehensive Income, net of taxes. However, since SPR recovers SFAS 87 and SFAS 106 costs through rates, these amounts will be recorded as Other Regulatory Assets under the provisions of SFAS 71, and will be recognized as expense over a period of time. For the twelve months ended December 31, 2006, 2005 and 2004, SPR recorded pension expense for all pension plans of approximately $30.6 million, $23.5 million and $28.3 million, respectively, in accordance with the provisions of SFAS No. 87. Actual payments of benefits made to retirees and terminated vested employees for the twelve months ended September 30, 2006, 2005 and 2004 were $21 million, $20.3 million and $17.5 million, respectively.

SPR has not made changes to pension plan provisions in 2006, 2005, and 2004 that had significant impacts on recorded pension expense for these years. As further described in Note 11, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements, SPR increased the discount rate used in determining pension expense from 5.75% in 2006 to 6.00% for the calendar year 2007. For 2006, SPR moved to a more up-to-date mortality table. SPR also updated termination and retirement assumptions used to value benefit obligations as of December 31, 2006 as a result of an experience study.

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 such as current discount rates, mortality assumption and/or 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 for all pension plans. While the chart below reflects an increase in the percentage for each assumption, SPR and its actuaries expect that a decrease would impact the projected benefit obligation (PBO) and the reported annual pension cost (PC) 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 (dollars in millions)	Change in Assumption Increase/ (Decrease)	Impact on PBO Increase/ (Decrease)	Impact on PC Increase/ (Decrease)
Discount rate	1%	$(82.4)	$(10.8)
Rate of return on plan assets	1%	N/A	$ (5.3)

In selecting an assumed discount rate for fiscal years 2006 and 2005 disclosures, and for fiscal years 2006 and 2005 pension cost, SPR's projected benefit payments were matched to the yield curve derived from a portfolio of over 500 high quality Aa bonds with yields within the 40th to 90th percentiles of these bond yields.

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. Investment returns on plan assets in the retirement plan gained approximately $34.4 million in 2006 and $55.7 million in 2005. These returns, in conjunction with SPR's contributions, have improved the funded status compared to prior years.

OTHER POSTRETIREMENT BENEFITS SPR's reported costs of providing other postretirement benefits (described in Note 11, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements) 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, discount rates and demographic (mortality, retirement, termination) assumptions used in determining the postretirement benefit obligation and postretirement costs.

For the twelve months ended December 31, 2006, 2005 and 2004, SPR recorded other postretirement benefit expense of approximately $14.6 million, $14.1 million and $13.4 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, 2006, 2005 and 2004 were $12.0 million, $8.1 million and $8.0 million, respectively.

SPR has not made changes to other postretirement benefit plan provisions in 2006, 2005 and 2004 that have had any significant impact on recorded benefit plan amounts. As further described in Note 11, Retirement Plan and Postretirement Benefits, of the Notes to Financial Statements, SPR has revised the discount rate for its 2006 disclosures to 6.00%, as compared to 2005 disclosures of 5.75%. For determining the expense to be recorded in 2007, SPR moved to a 6.00% discount rate from 5.75% in 2006. For 2006 expense, SPR also moved to a more up-to-date mortality table. SPR also updated termination and retirement assumptions used to value benefit obligations as of December 31, 2006 as a result of an experience study. The medical inflation trend assumption used to measure obligations was updated to reflect current expectations and recent experience by large employer health plans. 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 is proposing a change to the plan for SPPC's bargaining unit 1245 employees, which was ratified on February 28, 2007, with final approval expected in March 2007. The proposed change would require a re-measurement of plan obligations.

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 a decrease would impact the projected accumulated other postretirement benefit obligation (APBO) and the reported annual other postretirement benefit cost (PBC) on the income statement 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 (dollars in millions)	Change in Assumption Increase/ (Decrease)	Impact on APBO Increase/ (Decrease)	Impact on PBC Increase/ (Decrease)
Discount rate	1%	$(21.4)	$(1.9)
Health care cost trend rate	1%	$ 19.6	$ 3.4
Rate of return on plan assets	1%	N/A	$(0.8)

In selecting an assumed discount rate for fiscal year 2006 other postretirement benefits cost and disclosures, SPR's projected benefit payments were matched to the yield curve derived from a portfolio of over 500 high quality Aa bonds with yields within the 40th to 90th percentiles of these bond yields.

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. Investment returns on plan assets gained $8 million in 2006 and $0.4 million in 2005.

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, 2006, include unbilled receivables of $92 million and $83 million for NPC and SPPC, respectively. Customer accounts receivable as of December 31, 2005 include unbilled receivables of $80 million and $77 million for NPC and SPPC, respectively.

RECENT PRONOUNCEMENTS

See Note 1, Summary of Significant Accounting Policies, of the Notes to Financial Statements for discussion of accounting policies and recent pronouncements.

SIERRA PACIFIC RESOURCES

RESULTS OF OPERATIONS

Sierra Pacific Resources (Holding Company) and Other Subsidiaries

SPR (HOLDING COMPANY) The Holding Company's (stand-alone) operating results included approximately $51.4 million, $74.3 million and $88.3 million of long-term debt interest costs for the years ended December 31, 2006, 2005 and 2004, respectively. The decrease in interest costs were primarily due to the conversion of SPR's $300 million 7.25% Convertible Notes due 2010, the repurchase of the 7.93% Senior Notes associated with the PIES and the reduced interest rate of 7.803% on the Senior Notes associated with the New PIES. See Note 14, Common Stock and Other Paid-in Capital, of the Notes to Financial Statements for further discussion on SPR debt. The Holding Company's operating results for 2005 were negatively affected by early conversion fees of the Convertible Notes of approximately $35 million after taxes and unamortized debt issuance costs and legal fees associated with the Convertible Notes of approximately $4.7 million after taxes. See Note 6, Long-Term Debt of the Notes to Financial Statements, for further discussion of the conversion of the Convertible Notes. The Holding Company's operating results for 2004 were negatively affected by an impairment of goodwill of approximately $11.7 million and higher interest costs. The Holding Company recognized charges of approximately $23.7 million during 2004 for tender fees, interest costs and unamortized debt issuance costs associated with the early extinguishment of SPR's 8.75% Senior Unsecured Notes due 2005.

TUSCARORA GAS PIPELINE COMPANY (TGPC) TGPC, a wholly-owned subsidiary of SPR, sold its partnership interest in TGTC in December 2006. The gain from the sale of TGTC was approximately $40.9 million after taxes. TGPC contributed approximately $3.3 million after taxes in earnings for the year ended 2006 excluding the gain. TGPC contributed $5.1 million in net income applicable to common stock for the year ended December 31, 2005 and $5.2 million in net income applicable to common stock for the year ended December 31, 2004.

SIERRA PACIFIC COMMUNICATIONS SPC, a wholly-owned subsidiary of SPR, incurred a net loss of $263.4 thousand for the year ended December 31, 2006, a net loss of $103 thousand for the year ended December 31, 2005 and a net loss of $3.2 million for the year ended December 31, 2004. SPC's loss in 2004 was primarily due to the settlement with Sierra Touch America. See Note 17, Discontinued Operations and Disposal and Impairment of Long-Lived Assets, of the Notes to Financial Statements for further discussion.

OTHER SUBSIDIARIES Other Subsidiaries of SPR did not contribute materially to the consolidated results of operations of SPR.

Sierra Pacific Resources (Consolidated)

See Executive Overview, Results of Operations for SPR Consolidated.

ANALYSIS OF CASH FLOWS

SPR's consolidated net cash flows increased for the year ended December 31, 2006 compared to the same period in 2005, due to increases in cash from operating and financing activities, offset by cash used in investing activities. SPR received net proceeds of approximately $281 million from the issuance of 20 million shares of common stock in 2006. SPR also received approximately $100 million from the sale of TGTC. In December, SPR utilized a portion of the proceeds of common stock issuance and cash on hand for a tender offer that resulted in the extinguishment of approximately $85 million of SPR's 8.625% Senior Notes and approximately $25 million of the 7.803% Senior Notes.

At various times during 2006, NPC borrowed a total of $710 million under its revolving credit facility and repaid a total of $860 million, including $150 million borrowed in 2005, using the net proceeds of issuance of $905 million of NPC's General and Refunding Mortgage Notes, Series M, N and O and $200 million capital contribution from SPR. The remainder of the proceeds, together with the draw on the credit facility and cash from operations, was utilized to redeem approximately $563 million of outstanding debt and to pay associated costs and to finance net construction costs of $627 million. NPC also refinanced $92.5 million of tax exempt Revenue Bonds with newly issued auction rate Revenue Bonds during 2006.

At various times during 2006, SPPC borrowed approximately $248 million under its revolving credit facility, all of which was repaid during 2006. SPPC also issued $300 million in 6.0% General and Refunding Mortgage Notes, Series M, and $268 million in variable interest Pollution Control Revenue Bonds. A portion of the draw on the credit line was used to retire approximately $198 million of SPPC's Medium Term Notes Series A, B and C. The net proceeds of the $300 million offering were used to pay off the amount borrowed under the revolving credit facility, redeem $20 million of Medium Term Notes, Series C, redeem $50 million of preferred stock and to pay associated costs, premiums and dividends. Proceeds from Pollution Control Revenue Bonds and cash from operations were used to retire $269 million of SPPC's existing tax-exempt bonds.

Cash used for investing activities increased significantly when compared to 2005 primarily due to the acquisition of Silverhawk by NPC and the expansion of the Tracy Generating Station by SPPC. This increase was offset by the sale of the investment in Tuscarora for approximately $100 million and a reduction in construction at Lenzie that was placed in service in 2006.

Cash from operations increased during 2006 when compared to 2005 due to increases in deferred energy and general rates and a decrease in accounts receivable offset partially by the settlement with Enron. The increase was also offset by a reduction in accounts payable primarily associated with purchase power suppliers.

SPR's consolidated net cash flows decreased for the year ended December 31, 2005 compared to the same period in 2004, as a result of decreases in cash from operating and financing activities and an increase in cash used by investing activities. Cash flows for operating activities are lower in 2005 due to energy costs being higher than amounts recovered in rates in 2005. Offsetting the decrease in cash from operating activities was the $60 million escrow payment for Enron in 2004, a reduction in prepayments and deposits for energy in 2005 due to the establishment of the revolving credit facilities and an increase in general rates in the second quarter of 2004. The increase in cash used by investing activities was mainly due to construction at NPC for the Chuck Lenzie project. The decrease in cash from financing activities in 2005, when compared to 2004, was primarily due to the reduction of debt issued in 2005.

LIQUIDITY AND CAPITAL RESOURCES (SPR CONSOLIDATED)

Overall Liquidity

SPR's consolidated operating cash flows are primarily derived from the operations of NPC and SPPC. The primary source of operating cash flows for the Utilities is revenues (including the recovery of previously deferred energy costs and natural gas costs) from sales of electricity and natural gas. Significant uses of cash flows from operations include the purchase of electricity and natural gas, other operating expenses and interest.

Available Liquidity as of December 31, 2006

(in millions)	SPR	NPC	SPPC
Cash and cash equivalents	**$24.7**	**$ 36.6**	**$ 53.3**
Balance available on revolving credit facility	**N/A**	**545.0**	**340.6**
Total available liquidity	**$24.7**	**$581.6**	**$393.9**

SPR has approximately $42.5 million payable of debt service obligations for 2007, which it intends to pay through dividends from subsidiaries. (See "Factors Affecting Liquidity—Dividends from Subsidiaries" below.)

SPR and the Utilities anticipate that they will be able to meet operating costs such as fuel and purchased power costs with internally generated funds, including the recovery of deferred energy and external borrowings. However, to fund capital requirements, SPR and the Utilities may meet such financial obligations with a combination of internally generated funds, the use of the Utilities' revolving credit facilities, the issuance of long-term debt, and if necessary, capital contributions from SPR.

On a consolidated basis, SPR's overall liquidity continued to improve in 2006. The $200 million combined increase in the Utilities' revolving credit facilities provides additional liquidity for increased commodity prices. SPR's debt profile improved as a result of refinancing approximately $1.1 billion of long-term debt at the two Utilities. These refinancings are expected to reduce future interest expense.

SPR designs operating and capital budgets to control operating costs and capital expenditures. In addition to operating expenses, SPR has continuing commitments for capital expenditures for construction, improvement and maintenance of facilities.

Detailed below are SPR's Capital Structure, Capital Requirements, recently completed stock and financing transactions and factors affecting our ability to obtain debt on favorable terms, including the effect of our holding company structure and limitation on dividends from the Utilities.

Capital Structure (SPR Consolidated)

SPR's actual capital structure on a consolidated basis was as follows at December 31 (dollars in thousands):

	2006		2005	
Current maturities of long-term debt	**$ 8,348**	**0.1%**	$ 58,909	1.0%
Long-term debt	**4,001,542**	**60.3%**	3,817,122	63.8%
Preferred stock	**—**	**—**	50,000	0.8%
Common equity	**2,622,297**	**39.6%**	2,060,154	34.4%
Total	**$6,632,187**	**100%**	$5,986,185	100%

Capital Requirements

CONSTRUCTION EXPENDITURES SPR's annual consolidated cash construction expenditures have increased since 2003 and are expected to continue to increase due to programs designed to meet electric load growth and reliability needs. Cash construction expenditures for the years ended 2006, 2005 and 2004 were approximately $912 million, $590 million and $557 million, respectively. SPR's consolidated cash requirements for construction expenditures for 2007 are projected to be $1.4 billion. SPR's consolidated cash requirements for cash construction expenditures for 2007-2011 are projected to be $7.8 billion. To fund these capital projects, SPR and the Utilities may meet such financial obligations with a combination of internally generated funds, the use of the Utilities' revolving credit facilities, the issuance of long-term debt and, if necessary, capital contributions from SPR. Depending on the progress of the Ely Energy Center the timing and extent of the estimated capital expenditures necessary may change.

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, or Pension funding requirements as discussed in Note 11, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements, as of December 31, 2006, 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						
	2007	2008	2009	2010	2011	Thereafter	Total
NPC/SPPC long-term debt maturities	$ 8,348	$ 329,468	$102,738	$ 7,843	$ 369,734	$ 2,654,363	$ 3,472,494
NPC/SPPC long-term debt interest payments	215,941	203,602	192,614	192,188	175,159	1,663,305	2,642,809
SPR long-term debt maturities	—	—	—	—	—	549,209	549,209
SPR long-term debt interest payments	42,541	42,541	42,541	42,541	42,541	135,707	348,412
Purchased power	462,402	368,810	323,215	323,882	323,541	3,925,708	5,727,558
Coal and natural gas	451,269	147,851	123,467	95,525	82,856	544,908	1,445,876
Long-term service agreements[1]	15,979	13,867	24,267	22,037	12,148	123,783	212,081
Capital purchase agreements	13,121	—	—	—	—	—	13,121
Southern operations center lease	875	3,000	3,075	3,180	3,260	65,320	78,710
Operating leases	17,160	17,443	15,184	12,748	4,219	101,046	167,800
Total contractual cash obligations	$1,227,636	$1,126,582	$827,101	$ 699,944	$1,013,458	$ 9,763,349	$14,658,070

(1) Does not include equipment and services contracts related to the new peaking units at Clark Generating Station, entered into in February 2007.

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 is expected to decrease in 2007 by approximately $1.3 million compared to the 2006 cost of $30.6 million. As of September 30, 2006, the measurement date, the plan was fully funded on a FAS 87 ABO basis (fair value of assets exceeded ABO). During 2006, SPR contributed a total of $16 million to meet their funding obligations under the plan. At the present time it is not expected that any additional funding will be required in 2007 to meet the minimum funding level requirements defined by the Pension Benefit Guaranty Corporation and ERISA. However, SPR and the Utilities currently expect to contribute an amount similar to the 2006 funding. The amounts to be contributed may change subject to market conditions.

Capital Stock Transaction (SPR-Holding Company)

On May 1, 2006, SPR's shareholders approved an amendment to SPR's Restated Articles of Incorporation to increase the number of authorized shares of SPR common stock by 100 million shares, for a total amount of 350 million authorized shares.

In August 2006, SPR issued 20 million shares of its $1 par value common stock. Net proceeds from the issuance were $280.6 million. In August 2006, SPR contributed capital to NPC for approximately $200 million. NPC used the proceeds to repay indebtedness under its revolving credit facility. SPR invested the remaining proceeds in highly liquid short-term investments. In December 2006 these funds, along with net proceeds from the sale of TGTC and available cash on hand, were used to fund the tender offer of a portion of SPR debt and to make a capital contribution to SPPC of approximately $75 million (see Overall Liquidity above). As of December 31, 2006, SPR had approximately 221 million shares of common stock issued and outstanding.

Financing Transactions (SPR-Holding Company)

TENDER OFFER In November 2006, SPR commenced tender offers for up to $110 million aggregate principal amount of its 7.803% Senior Notes due 2012, its 8.625% Senior Notes due 2014, and its 6.75% Senior Notes due 2017. Each of the offers was conditioned on SPR purchasing no more than an aggregate principal amount of $110 million of all notes validly tendered. To meet this condition, SPR terminated the offer for the 6.75% Notes. In December 2006 approximately $25 million of the 7.803% Senior Notes outstanding and approximately $85 million of the 8.625% Senior Notes outstanding were validly tendered and accepted by SPR. The total consideration paid was approximately $120.6 million (which included an early tender premium and accrued interest). As of December 31, 2006 the outstanding balances for the 7.803% Senior Notes and 8.625% Senior Notes were $74.2 million and $250.0 million, respectively.

Factors Affecting Liquidity

EFFECT OF HOLDING COMPANY STRUCTURE As of December 31, 2006, SPR (on a stand-alone basis) has outstanding debt and other obligations including, but not limited to: $74.2 million of its unsecured 7.803% Senior Notes due 2012; $225 million of its unsecured 6.75% Senior Notes due 2017; and $250 million of its unsecured 8.625% Senior Notes due 2014.

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 the creditors of NPC and SPPC and its other subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders.

As of December 31, 2006, SPR, NPC, SPPC and their subsidiaries had approximately $4.01 billion of debt and other obligations outstanding, consisting of approximately $2.39 billion of debt at NPC, approximately $1.07 billion of debt at SPPC and approximately $549 million of debt at the holding company and other subsidiaries. Although SPR and the Utilities are parties to agreements that limit the amount of additional indebtedness they may incur, SPR and the Utilities retain the ability to incur substantial additional indebtedness and other liabilities.

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 impose limits on investment returns or otherwise impact the amount of dividends that the Utilities may declare and pay. In the PUCN order for Docket 05-10024 and 05-10025, issued in February 2006, a dividend restriction was instituted for both Utilities. Under this restriction, the combined amount that NPC and SPPC may pay to SPR each year is limited to the actual cash necessary to service SPR's debt for the year. At the time of the order, SPR and the Utilities were only rated by Standard & Poor's ("S&P"), Moody's Investors Service, Inc. ("Moody's") and Fitch Ratings Ltd. ("Fitch"). The PUCN order states that the dividend restriction will continue until NPC's and SPPC's senior secured debt obtains an investment grade rating from two of the three credit rating agencies, but did not specify which rating agencies. In February 2007, Dominion Bond Rating Service ("DBRS"), who had not previously issued ratings on the companies, assigned ratings for SPR, NPC and SPPC. DBRS and Fitch currently rate NPC and SPPC's senior secured debt at the minimum level for investment grade. It is not clear what effect, if any, the DBRS rating will have on the PUCN dividend restriction. See Credit Ratings below for discussion of current ratings.

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 agreements entered into by the Utilities, restrictions on dividends contained in agreements to which NPC and SPPC are party, as well as specific regulatory limitations on dividends, are discussed in Note 8, Debt Covenant and Other Restrictions.

In addition to the restrictions imposed by specific agreements, the Federal Power Act prohibits the payment of dividends from "capital accounts." Although the meaning of this provision is unclear, the Utilities believe that the Federal Power Act restriction, as applied to their particular circumstances, would not be construed or applied by the FERC to prohibit the payment of dividends for lawful and legitimate business purposes from current year earnings, or in the absence of current year earnings, from other/additional paid-in capital accounts. If, however, the FERC were to interpret this provision differently, the ability of the Utilities to pay dividends to SPR could be jeopardized.

As of December 31, 2006 each Utility was able to pay dividends, subject to a cap, under the most restrictive test in its financing agreements; however, the total amount of dividends that the Utilities can pay to SPR under their financing agreements does not currently significantly restrict their ability to pay dividends because the maximum amount of dividends that can be paid under their financing agreements is greater than the amount that the Utilities can pay under the PUCN dividend restriction. In 2006, NPC paid $35.8 million and declared an additional $13.5 million in dividends to SPR, and SPPC paid $17.9 million and declared an additional $6.7 million in dividends to SPR. In January 2007, SPPC paid $6.7 million in dividends to SPR, and NPC paid $13.5 million in dividends to SPR.

CREDIT RATINGS SPR, NPC and SPPC are rated by four Nationally Recognized Statistical Rating Organizations: S&P, Moody's, Fitch, and DBRS. As of February 23, 2007, the ratings are as follows:

		Rating Agency			
		DBRS	Fitch	Moody's	S&P
SPR	Sr. unsecured debt	BB (low)	BB-	B1	B
NPC	Sr. secured debt	BBB (low)*	BBB-*	Ba1	BB+
NPC	Sr. unsecured debt	Not rated	BB	Not rated	B
SPPC	Sr. secured debt	BBB (low)*	BBB-*	Ba1	BB+

** Ratings are investment grade*

In February 2007, DBRS, who had not previously issued ratings on the companies, assigned new ratings to SPR, NPC and SPPC. The ratings for the senior secured debt of NPC and SPPC are BBB (low), which is the minimum level for investment grade. The rating assigned to SPR's Senior Notes is BB (low), which is non-investment grade. DBRS's trend for all three companies is Stable.

In 2006, there were other changes to the ratings of the three companies. Fitch upgraded the ratings of SPR and the Utilities. The ratings for the senior secured debt of NPC and SPPC were increased to BBB-, the minimum level for investment grade. The senior unsecured debt for NPC was upgraded from BB- to BB, which is still non-investment grade. Fitch revised the rating outlook for SPR and the Utilities from Positive to Stable. S&P upgraded the ratings of NPC's and SPPC's senior secured debt from BB to BB+, one level below investment grade. Moody's reaffirmed its ratings for NPC's and SPPC's senior secured debt at Ba1, one level below investment grade.

A security rating is not a recommendation to buy, sell or hold securities. Security ratings are subject to revision and withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating.

ENERGY 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 request adequate financial assurance, which, if not provided within three 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 three 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 December 31, 2006 for all suppliers continuing to provide power under a WSPP agreement would approximate a $55.8 million payment by NPC and an approximate $44.5 million payment by SPPC. These contracts qualify for the normal purchases scope exception of SFAS No. 133, and as such, are not required to be marked to market on the balance sheet. Refer to Note 9, Derivatives and Hedging Activities, of the Notes to Financial Statements for further discussion.

GAS SUPPLIER ISSUES With respect to the purchase and sale of natural gas, NPC and SPPC use several types of standard industry contracts. 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. Because of creditworthiness concerns, most contracts and confirmations for natural gas purchases have been modified or separate agreements have been made to either shorten the normal payment due date or require payment in advance of delivery. At the present time, four counterparties require payment in advance of delivery.

Gas transmission service is secured under FERC Tariffs or custom agreements. These service contracts and Tariffs require the user to establish and maintain creditworthiness to obtain service or otherwise post cash or a letter of credit to be able to receive service. Service contracts are subject to FERC approved tariffs, which, under certain circumstances, require the Utilities to provide collateral to continue receiving service.

Financial Covenants

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY Each of NPC's $600 million Second Amended and Restated Revolving Credit Agreement and SPPC's $350 million Amended and Restated Revolving Credit Agreement, dated November 2005 and amended in April 2006, contains two financial maintenance covenants. The first requires that the Utility maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that the Utility maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1. As of December 31, 2006, both Utilities were in compliance with these covenants.

Limitations on Indebtedness

SIERRA PACIFIC RESOURCES The terms of SPR's $250 million 8.625% Senior Unsecured Notes due March 2014, $74.2 million 7.803% Senior Unsecured Notes due 2012 and $225 million 6.75% Senior Unsecured Notes due 2017 restrict SPR and any of its Restricted Subsidiaries (NPC and SPPC) from incurring any additional indebtedness unless:

1. at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for SPR's most recently ended four-quarter period on a pro forma basis is at least 2 to 1, or
2. the debt incurred is specifically permitted under the terms of the respective series of Senior Notes, which permits the incurrence of 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 supporting SPR's or any Restricted Subsidiary's obligations to energy suppliers, or
3. the indebtedness is incurred to finance capital expenditures pursuant to NPC's 2003 Integrated Resource Plan and SPPC's 2004 Integrated Resource Plan.

If the respective series of Senior Notes are upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the respective series of Senior Notes remain investment grade. As of December 31, 2006, SPR, NPC and SPPC would have been able to issue approximately $2.1 billion of additional indebtedness on a consolidated basis, assuming an interest rate of 7%, per the requirement stated in number 1 above.

NEVADA POWER COMPANY Certain factors impact NPC's ability to issue debt:

1. Financing Authority from the PUCN. In February 2006 NPC received PUCN authorization to enter into financings of $1.78 billion, which amount included $600 million for the revolving credit facility (described above). NPC has issued approximately $100 million of the new debt authorized under the PUCN Order. NPC's only remaining authority under this PUCN Order allows NPC to refinance its existing debt and to use its $600 million revolving credit facility.
2. Limits on Bondable Property. To the extent that NPC has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, NPC's ability to issue secured debt is still limited by the amount of bondable property or retired bonds that can be used to issue debt under its General and Refunding Mortgage Indenture. As of December 31, 2006, NPC had the capacity to issue $672 million of General and Refunding Mortgage Securities.

3. Financial Covenants in its and SPR's financing agreements. The terms of certain SPR debt further prohibit NPC and SPPC from incurring additional indebtedness unless certain conditions have been met. In addition to the SPR debt, the terms of certain NPC debt and the revolving credit facility restrict NPC from incurring any additional indebtedness unless certain covenants are satisfied. See Note 8, Debt Covenant and Other Restrictions, of the Notes to Financial Statements in this report.

As of December 31, 2006, the financial covenants under the revolving credit facility, which are more restrictive than the financial covenants found in other NPC debt, would allow NPC to issue up to $2.2 billion of additional debt. The covenant limitations of certain SPR debt place a cap on additional indebtedness, on a consolidated basis, including SPPC and NPC, of $2.1 billion as of December 31, 2006. However, since NPC currently has no PUCN authority to issue new debt, NPC is limited to borrowing under its credit facility. As of February 23, 2007, the balance available under the credit facility is $476.3 million.

Since SPR's debt covenant limitations are calculated on a consolidated basis, SPR's debt covenant limitations may allow for higher or lower borrowings than $2.1 billion, depending on the Utilities' combined usage of their respective revolving credit facilities at the time of the covenant calculation.

SIERRA PACIFIC POWER COMPANY Certain factors impact SPPC's ability to issue debt:

1. Financing Authority from the PUCN. In February 2006, SPPC received PUCN authorization to enter into financings of $1.36 billion, which amount includes $350 million for the revolving credit facility (described above). SPPC has issued $21 million of the new debt authorized in the PUCN Order. SPPC's remaining authority under this PUCN Order allows SPPC to use its $350 million revolving credit facility to issue $349 million in new debt and to refinance existing debt as specified in the order.
2. Limits on Bondable Property. To the extent that SPPC has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, SPPC's ability to issue secured debt is still limited by the amount of bondable property or retired bonds that can be used to issue debt under the General and Refunding Mortgage Indenture. As of December 31, 2006, SPPC has the capacity to issue $381 million of General and Refunding Mortgage Securities.
3. Financial Covenants in its and SPR's financing agreements. The terms of certain SPR debt further prohibit SPPC and NPC from incurring additional indebtedness unless certain conditions have been met. In addition to the SPR debt, the terms of certain SPPC debt and the revolving credit facility restrict SPPC from incurring any additional indebtedness unless certain covenants are satisfied. See Note 8, Debt Covenant and Other Restrictions, of the Notes to Financial Statements in this report.

As of December 31, 2006, the financial covenants under the revolving credit facility, which are more restrictive than the financial covenants found in other SPPC debt, would allow SPPC to issue up to $797 million of additional debt. The covenant limitations of certain SPR debt place a cap on additional indebtedness, on a consolidated basis, including SPPC and NPC, at $2.1 billion as of December 31, 2006. As of February 23, 2007, the balance available under the credit facility is $331.1 million.

Since SPR's debt covenant limitations are calculated on a consolidated basis, SPR's debt covenant limitations may allow for higher or lower borrowings than $2.1 billion, depending on the Utilities' combined usage of their revolving credit facilities at the time of the covenant calculation.

Cross Default Provisions

None of the Utilities' financing agreements contains a cross-default provision that would result in an event of default by that Utility upon an event of default by SPR or the other Utility under any of their respective financing agreements. Certain of SPR's financing agreements, however, do contain cross-default provisions that would result in event of default by SPR upon an event of default by the Utilities under their respective financing agreements. In addition, certain financing agreements of each of SPR and the Utilities provide for an event of default if there is a failure under other financing agreements of that entity 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.

ENERGY SUPPLY (UTILITIES)

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 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. Some 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 IRP filed every three years, which has a twenty-year planning horizon;

(2) the Energy Supply Plan ("ESP"), which is an intermediate term resource procurement and risk management plan that establishes the supply portfolio strategies 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 ESP operates in conjunction with the PUCN-approved twenty-year IRP. It serves as a guide for near-term execution and fulfillment of energy needs. When the ESP calls for executing contracts with a duration of more than three years, the IRP regulations require PUCN approval as part of the resource planning process.

In developing energy supply plans and executing such plans, management guidelines followed by the Utilities include:

- Maintaining an energy supply plan that balances the goals of minimizing costs, risks and price volatility (retail price stability), while maximizing reliability and predictability of supply.
- Investigating feasible commercial options to execute the ESP.
- Applying quantitative techniques and diligence commensurate with risk to evaluate and execute each transaction.
- Monitoring the portfolio against evolving market conditions and managing the resource optimization options.
- Ensuring 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 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 thresholds 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 IRPs 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. NPC's IRP was filed in June 2006 and received approval in November 2006. SPPC's IRP was filed in July 2004 and approved on November 2004. Between IRP filings, the Utilities are required to seek PUCN approval for modifications to their resource plans and for power purchases with terms of three years or greater by filing amendments to prior IRP filings.

The Utilities 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 recovery in rates.

Intermediate Term Energy Supply Plans

The Utilities update their intermediate term ESPs on an annual basis. In June 2006, NPC filed a new 20-year IRP, which included an ESP for years 2007-2009. In July 2006, SPPC filed the Thirteenth Amendment to its 2004 IRP which included, among other things, an ESP update for the remaining year of the planning cycle, 2007. Both plans were approved by the EROC and the CEO prior to submission to the PUCN. The Energy Supply Plans operate within the framework of the PUCN-approved twenty-year IRPs. They serve as a guide for near-term execution and fulfillment of energy needs. When the ESPs call for the execution of contracts of duration of more than three years, an amendment to the IRP is prepared and submitted for PUCN approval. The fuel, power procurement and risk management strategies contained in the ESPs filed in 2006 were found to be reasonable and prudent by the PUCN in November 2006.

In 2006, NPC added a significant amount of new, efficient, generating capacity to its system (Lenzie 1 and 2, Silverhawk and Harry Allen 4), essentially doubling the amount of Company-owned generating resources. For the remainder of their power needs, the PUCN approved ESPs provide for a competitive acquisition process to secure the required resources. Both Utilities have issued Requests For Proposals and executed forward contracts for their peak resource needs for the summer of 2007. The portfolio mix consists of owned generating resources, forward contracts for power and peaking and seasonal capacity, or synthetic tolling based contracts (i.e., power prices indexed to gas prices), to meet the following requirements:

- Optimize the trade-off between overall fuel and purchase power cost and market price and supply 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 some counterparties in weak financial conditions.
- Procure to match a difficult load profile, to the extent possible.
- Hedge the gas price risk exposure in the fuel portfolio through the purchase of a set of risk management options.
- Manage 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).

Both of the ESPs reflect the Utilities' strategies, embedded in their filed IRPs, to minimize supply and price risk through acquisition or construction of company owned generating resources in the intermediate term (e.g., peaking capacity at Clark Generating Station; Tracy combined-cycle addition), forward contracts to meet capacity needs in the shorter term, and pursuit of fuel diversity options such as coal and renewables in the longer term.

Long-Term Purchase Power Activities

The Utilities update their long-term energy supply plans on an annual basis in concert with the preparation of their respective ESPs, which are described in the preceding section. As noted above, the ESPs serve as a guide for near-term execution and fulfillment of energy needs. When the energy supply plans call for contracts of duration more than three years, requests for proposals are issued, bids are evaluated, and contracts are executed with the successful bidders. Those contracts are submitted to the PUCN for approval through an amended IRP.

As noted in the preceding section, the Utilities have reduced their longer-term needs for power from those in prior years. The Utilities have not entered into a long-term purchase agreement for conventional power since 2003. Currently, NPC has approximately 1,329 MW of long-term contracts with various providers, terms and expiration dates, and 305 MWs of long-term contracts with Qualifying Facilities. SPPC currently has 83 MWs of long-term contracts which expire by 2009.

The Utilities also entered into long-term contracts with renewable energy providers.

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 and operating reserve requirement. The Utilities commit and dispatch generating units based on the comparative economics of generation versus spot-market purchase opportunities. Any amount of excess capacity or energy is sold on the wholesale market, while any deficient capacity or energy position is filled by either buying on the spot market or utilizing available generating capacity.

The day-ahead resource optimization begins with an analysis of projected hourly loads, existing resources and operating reserve requirements. Firm forward take-or-pay contracts are scheduled and counted towards meeting the capacity needs of the day being pre-scheduled. The day-of resource optimization involves minimizing system production costs each hour by lowering or raising generating unit output or buying power and/or selling excess power in the wholesale market all in order to meet the system load requirement and operating reserve requirement. 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 available excess energy when it exists.

Real-time resource optimization requires an hourly determination of whether to increase or decrease the loading of on-line generating units, commit previously off-line generating units, un-commit on-line generating units, sell excess power, or purchase power in the real-time market to meet the companies' resource needs. In order to achieve the lowest production cost, the projected incremental or decremental cost of the next available generation resource options is compared to determine the lowest cost option.

Additional generating assets are expected to result in an uncommitted long peak position during the shoulders months. This will present resource procurement with the opportunity to implement a more active asset optimization strategy.

NEVADA POWER COMPANY

RESULTS OF OPERATIONS

NPC recognized net income of $224.5 million in 2006 compared to net income of $132.7 million in 2005 and $104.3 million in 2004. NPC's operating results for 2006 improved over 2005 primarily as a result of the July 2006 Nevada Supreme Court ruling which allows NPC to recover the approximate $180 million of the previously disallowed deferred energy costs and the carrying charge associated with the Lenzie Generating Station, partially offset by increased interest expense. NPC's operating results for 2005 improved over 2004 primarily as a result of an increase in operating income, as discussed in detail below, an increase in Allowance for Other Funds Used During Construction and Allowance for Borrowed Funds During Construction and lower interest costs.

In 2006, NPC paid $35.8 million in dividends to SPR and declared an additional $13.5 million dividend. In 2005, NPC paid and declared common stock dividends of $35.3 million to SPR.

Gross margin is presented by NPC in order to provide information by segment that management believes aids the reader in determining how profitable the electric business is at the most fundamental level. Gross margin, which is a "non-GAAP financial measure" as defined in accordance with SEC rules, provides a measure of income available to support the other operating expenses of the business and is utilized by management in its analysis of its business.

NPC believes presenting gross margin allows the reader to assess the impact of NPC's regulatory treatment and its overall regulatory environment on a consistent basis. Gross margin, as a percentage of revenue, is primarily impacted by the fluctuations in regulated electric and natural gas supply costs versus the fixed rates collected from customers. While these fluctuating costs impact gross margin as a percentage of revenue, they only impact gross margin amounts if the costs cannot be passed through to customers. Gross margin, which NPC calculates as operating revenues less fuel and purchased power costs, provides a measure of income available to support the other operating expenses of NPC. Gross margin changes based on such

factors as general base rate adjustments (which are required to be filed by statute every two years) and reflect NPC's strategy to increase internal power generation versus purchased power, which generates no gross margin.

The components of gross margin for the years ended December 31 (dollars in thousands):

Year ended December 31,	2006	Change from Prior Year	2005	Change from Prior Year	2004
Operating Revenues:					
Electric	**$2,124,081**	**12.8%**	$1,883,267	5.6%	$1,784,092
Energy Costs:					
Purchased power	**764,850**	**-20.6%**	963,888	26.1%	764,347
Fuel for power generation	**552,959**	**99.6%**	277,083	17.7%	235,404
Deferral of energy costs disallowed	**—**	**—**	—	-100.0%	1,586
Deferral of energy costs—net	**92,322**	**-302.2%**	(45,668)	-133.6%	135,973
	$1,410,131	**18.0%**	$1,195,303	5.1%	$1,137,310
Gross margin before reinstatement of deferred energy	**$ 713,950**	**3.8%**	$ 687,964	6.4%	$ 646,782
Reinstatement of deferred energy	**$ 178,825**	**N/A**	$ —	N/A	$ —
Gross margin after reinstatement of deferred energy	**$ 892,775**	**29.8%**	$ 687,964	6.4%	$ 646,782

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

	2006		2005		2004
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Electric Operating Revenues:					
Residential	**$ 975,568**	**18.5%**	$ 823,095	7.9%	$ 762,907
Commercial	**442,477**	**12.0%**	395,016	6.1%	372,271
Industrial	**631,762**	**12.8%**	560,059	5.7%	529,916
Retail revenues	**2,049,807**	**15.3%**	1,778,170	6.8%	1,665,094
Other[1]	**74,274**	**-29.3%**	105,097	-11.7%	118,998
Total revenues	**$2,124,081**	**12.8%**	$1,883,267	5.6%	$1,784,092
Retail sales in thousands of megawatt-hours (MWh)	**20,820**	**7.0%**	19,455	4.6%	18,607
Average retail revenue per MWh	**$ 98.45**	**7.7%**	$ 91.40	2.1%	$ 89.49

(1) Primarily wholesale, as discussed below.

NPC's retail revenues increased in 2006 compared to 2005 due to increases in retail rates, customer growth and weather. Retail rates increased as a result of NPC's various Base Tariff Energy Rate (BTER) and deferred energy cases (see "Regulatory Proceedings"). Residential, commercial and industrial customers increased by 4.9%, 5.1% and 4.3%, respectively. Customer usage increased due to colder winter weather and hotter spring weather. Based on NPC's projected customer forecast, NPC expects retail electric customers in the Clark County area to continue to grow in 2007.

In November 2006, NPC filed its General Rate Case with the PUCN. The filing requests an overall rate increase, with rates to be effective June 1, 2007. In January 2007, NPC filed its annual deferred energy filing and an application to request recovery of deferred legal and settlement costs incurred for terminated power contracts executed during the Western Energy Crisis. If approved by the PUCN, the overall effect of both filings would be a slight decrease in rates. NPC requested that the rates become effective on June 1, 2007. A decision on these cases is expected in the spring of 2007. For further discussion on the various cases see Regulatory Proceedings, later.

NPC's retail revenues were higher in 2005 compared to 2004 primarily due to customer growth and higher rates. Increases in the number of residential, commercial and industrial customers were 5.5%, 5.7% and 3.8%, respectively. Higher rates became effective in April 2004, which were the result of NPC's 2003 General and Deferred Rate Cases and October 2005, as a result of NPC's 2005 BTER Update. These increases were slightly offset by a decrease resulting from NPC's 2004 Deferred Energy Rate Case effective April 2005.

Electric Operating Revenues—Other decreased in 2006 compared to 2005, primarily due to revenues associated with Mohave which have been reclassified to Other Regulatory Assets as a result of the shut down of the Mohave Generating Station. For further discussion on Mohave refer to Note 13, Commitments and Contingencies, in the Notes to Financial Statements. Also contributing to the decrease was a decrease in transmission revenues as a result of the purchase of Silverhawk. In 2005, the previous owner of Silverhawk used NPC's transmission system to distribute electricity from the facility.

The decrease in Electric Operating Revenues—Other in 2005 compared to 2004 was primarily due to certain types of transactions that were reported in revenues for 2004, which are now netted in purchased power. The decrease also included decreased energy usage by Public Authority customers due to their transitioning to distribution only services by purchasing their energy from other sources, as allowed by Nevada law under certain circumstances. Partially offsetting this decrease was a refund in 2004 of $5.9 million owed to transmission customers as a result of FERC's approval of a tariff agreement in July 2004. For further discussion on the Transmission case see Note 3, Regulatory Actions, of the Notes to Financial Statements. The tariff agreement also lowered the transmission rates which contributed to the decrease in 2005 revenues.

Purchased Power

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Purchased Power	**$764,850**	**-20.6%**	$963,888	26.1%	$764,347
Purchased power in thousands of MWh	**10,248**	**-20.5%**	$ 12,894	4.7%	$ 12,319
Average cost per MWh of purchased power	**$ 74.63**	**-0.2%**	$ 74.75	20.5%	$ 62.05

NPC's purchased power costs decreased in 2006 compared to 2005, primarily due to an increase in internal generation with the addition of the Silverhawk and Lenzie plants. As a result, the volume of MWh purchased decreased compared to the prior year.

NPC's purchased power costs increased in 2005 compared to 2004, due to higher prices and increased volume. NPC's energy contracts calculate prices using gas indexes; therefore, higher natural gas prices in 2005 increased the price of purchased power. Furthermore, purchased power costs were higher due to gas tolling agreements entered into during the second quarter of 2004 and June 2005. These gas tolling agreements are purchased power agreements where NPC provides natural gas to the supplier who generates the energy for NPC. The gas tolling agreements are based on gas indexes; therefore, the increase in natural gas prices increased the cost of purchased power. Volume increased because NPC satisfied more of its native load requirements through purchased power rather than generation.

Fuel for Power Generation

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Fuel for Power Generation	**$552,959**	**99.6%**	$277,083	17.7%	$235,404
Thousands of MWhs generated	**12,160**	**50.2%**	$ 8,094	-4.4%	$ 8,470
Average fuel cost per MWh of generated power	**$ 45.47**	**32.8%**	$ 34.23	23.2%	$ 27.79

Fuel for power generation increased in 2006 as compared to 2005 due to several factors:

- With the addition of Silverhawk and Lenzie it was more economical for NPC to rely on its own generation rather than the purchase of power. As a result, the increase in volume of MWhs generated increased significantly compared to the prior year.
- The shutdown of Mohave as of the beginning of the year increased the cost per MWh of generated power. Although Silverhawk and Lenzie are highly efficient generation stations, the cost of coal is substantially lower than the cost of natural gas. Mohave generation during 2005 represented approximately 17% of total generation.
- Hedging instruments purchased when gas prices were escalating as a result of the 2005 hurricanes in the southern United States increased fuel for power generation costs. The settlement of these instruments during 2006 negatively impacted the average cost per MWh as natural gas prices were decreasing during this period.

Fuel for power generation costs increased in 2005 as compared to 2004 due to the increased price of natural gas. The decrease in volume of generation was primarily due to NPC satisfying more of its native load requirements through purchased power rather than generation. The increase in average unit fuel cost per megawatt-hour was primarily due to higher gas costs in 2005 compared to 2004.

Deferral of Energy Costs—Net

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Reinstatement of deferred energy	**$(178,825)**		$ —		$ —
Deferred energy costs disallowed	**—**		—		1,586
Deferral of energy costs—net	**92,322**	**N/A**	(45,668)	N/A	135,973
	$ (86,503)		$ (45,668)		$137,559

Reinstatement of deferred energy represents the July 2006 decision by the Nevada Supreme Court which ruled that NPC is allowed to recover approximately $180 million of previously disallowed deferred energy and directed the District Court to remand the issue back to the PUCN to determine the rate schedule that will be used to recover this amount. In all other respects, the Nevada Supreme Court affirmed the District Court's decision on the PUCN disallowance. As a result of the Nevada Supreme Court decision, NPC recorded approximately $180 million before tax of the previously disallowed deferred energy in its Consolidated Income Statement as "Reinstatement of Deferred Energy." See Regulatory Proceedings for further discussion of the $180 million of deferred energy.

Deferred energy costs disallowed for 2004 reflect the first quarter write-off of $1.6 million in electric deferred energy costs incurred during the twelve months ended September 30, 2003 that were disallowed by the PUCN in their March 2004 decision in NPC's deferred energy rate case.

Deferred energy costs—net represent the difference between actual fuel and purchased power costs incurred during the period and amounts recoverable through current rates. To the extent actual costs exceed amounts recoverable through current rates, the excess is recognized as a reduction in costs. Conversely, to the extent actual costs are less than amounts recoverable through current rates, the difference is recognized as an increase in costs. Deferred energy costs—net also include the current amortization of fuel and purchased power costs previously deferred. See Note 1, Summary of Significant Accounting Policies, Deferral of Energy Costs, of Notes to Financial Statements for further detail of deferred energy balances.

Amounts for 2006, 2005 and 2004 include amortization of deferred energy costs of $120.5 million, $131.5 million and $228.8 million, respectively; and under-collections of amounts recoverable in rates of $28.2 million, $177.1 million and $92.7 million, respectively.

Allowance for Funds Used During Construction (AFUDC)

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Allowance for other funds used during construction	**$11,755**	**-37.1%**	$ 18,683	341.7%	$ 4,230
Allowance for borrowed funds used during construction	**11,614**	**-49.9%**	$ 23,187	304.1%	$ 5,738
	$23,369	**-44.2%**	$ 41,870	320.0%	$ 9,968

AFUDC for NPC was lower in 2006 compared to 2005 due to a decrease in Construction Work in Progress (CWIP) balance on which AFUDC is calculated. The decrease in the average CWIP balance was primarily due to the completion of Blocks 1 and 2 of the Chuck Lenzie Station and Harry Allen Unit 4 in early spring of 2006.

AFUDC was higher in 2005 compared to 2004 due to the construction of Blocks 1 and 2 of the Lenzie Generating Station.

Other (Income) and Expenses

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Other operating expense	**$218,120**	**3.4%**	$211,039	14.9%	$183,736
Maintenance expense	**$ 61,899**	**18.9%**	$ 52,040	-8.7%	$ 57,030
Depreciation and amortization	**$141,585**	**14.1%**	$124,098	4.4%	$118,841
Interest charges on long-term debt	**$171,188**	**7.6%**	$159,106	4.2%	$152,764
Interest for energy suppliers	**$ —**	**N/A**	$ (14,825)	-38.7%	$ (24,171)
Interest charges—other	**$ 17,038**	**25.6%**	$ 13,563	-6.7%	$ 14,533
Carrying charge for Lenzie	**$ (33,440)**	**N/A**	$ —	N/A	$ —
Interest accrued on deferred energy	**$ (21,902)**	**7.6%**	$ (20,350)	0.7%	$ (20,199)
Other income	**$ (16,992)**	**-33.7%**	$ (25,626)	12.2%	$ (22,844)
Disallowed merger costs		**N/A**	$ —	N/A	$ 3,961
Other expense	**$ 8,480**	**-0.5%**	$ 8,525	27.9%	$ 6,665

Other operating expense increased in 2006 compared to 2005 due to various costs, all of which were not individually significant. These increases were partially offset by a decrease in legal fees and operating expense related to Mohave, Reid Gardner and Clark compared to 2005.

Other operating expense increased for 2005 compared to 2004 primarily due to increased advisory fees, amortization of regulatory assets and severance costs associated with the reorganization of SPPC, NPC and SPR.

The increase in Maintenance expense in 2006 compared to 2005 was primarily due to the addition of Lenzie and Silverhawk Generating Stations in 2006; partially offset by reduced maintenance expenses for Mohave and Navajo.

The decrease in Maintenance expense in 2005 compared to 2004 was due to the timing of scheduled and unscheduled plant maintenance at Clark Station, Reid Gardner and Navajo during 2004.

Depreciation and amortization increased in 2006 compared to 2005 primarily as a result of increases in plant-in-service. The increase is primarily due to the purchase of Silverhawk and completion of the Harry Allen Unit IV. The increase in depreciation and amortization expense between 2005 and 2004 was the result of routine increases to plant-in-service to serve regular system growth.

Interest charges on Long-Term Debt increased for the year ended December 31, 2006 compared to 2005 due primarily to the issuance in January 2006 of $210 million Series M, General and Refunding Mortgage Notes and the use of the Revolving Credit Facility, partially offset by various refinancings of debt at lower interest rates. The $210 million was issued to fund the acquisition of the Silverhawk Generating Facility. Interest charges related to this issuance was approximately $11.9 million. NPC's use of the Revolving Credit Facility increased in 2006 primarily due to increased capital expenditures and fuel and purchase power expenses. Interest expense for the Revolving Credit Facility was approximately $12 million compared to $1.9 million in the prior year.

Interest charges on Long-Term Debt increased slightly for the year ended December 31, 2005 compared to 2004 due primarily to increases in long-term debt balances related to new debt issued in November 2004 of $250 million, interest associated with various draws from the Long-Term Credit Facility in 2005, and an increase in interest rates on NPC's $115 million variable rate interest notes in 2005. This increase was partially offset by debt redemptions, in July 2005 of $87.5 million and $122.5 million. See Note 6, Long-Term Debt, of the Notes to Financial Statements for additional information regarding long-term debt.

NPC's interest charges for energy suppliers are comprised of interest accruals for terminated supplier balances that had been subject to litigation. The amount reported in 2005 includes reversals of accrued balances due to settlements reached with suppliers. The amount reported in 2004 includes the reversal of $28 million resulting from a ruling by the U.S. District Court that lowered the interest rate previously accrued. See Note 13, Commitments and Contingencies, of the Notes to Financial Statements, for more information regarding the Enron litigation.

NPC's Interest charges—other increased for the year ended December 31, 2006 when compared to the same period in 2005 due to higher costs related to new debt issues and redemptions. Interest charges—other for the year ended December 31, 2005 decreased compared to the same period in 2004 following reduced charges related to NPC's short-term credit facilities. These costs were offset with additional costs associated with the debt redemption of $210 million in July 2005. See Note 6, Long-Term Debt, of the Notes to Financial Statements, for additional information regarding long-term debt.

NPC's carrying charges on Lenzie for the year ended December 31, 2006 represent carrying charges earned on the incurred debt component of the acquisition and construction costs of the completed Lenzie Generating Station. The PUCN authorized NPC to accrue a carrying charge for the cost of acquisition and construction until the plant is included in rates. See Note 1 of the Notes to Financial Statements for discussion of the accounting for the carrying charge for Lenzie.

NPC's Interest accrued on deferred energy for the year ended December 31, 2006 were slightly higher than the same period in 2005 due to slightly higher average deferred energy balances during 2006, excluding deferred energy assets of $179 million associated with the Nevada Supreme Court decision reversing the deferred energy costs disallowance. NPC's interest accrued on deferred energy costs was comparable for 2005 to 2004. See Note 3, Regulatory Actions of the Notes to Financial Statements for further discussion of deferred energy accounting issues and Note 13, Commitments and Contingencies of the Notes to Financial Statements for further discussion of the Nevada Supreme Court decision.

Disallowed merger costs for the year ended December 31, 2004 were a result of the PUCN decision in NPC's 2003 General Rate Case. The PUCN decision permitted substantially all of the merger costs that NPC requested recovery of, except for a 20% reduction in merger costs that were to be amortized over the next two years. Also included in the write-off are merger costs allocable to non-Nevada jurisdictional sales that NPC had determined not to be recoverable in rates. See "Regulatory Proceedings"—and Note 3, Regulatory Actions, of the Notes to Financial Statements for additional information regarding NPC's recovery of merger costs.

NPC's Other income decreased for the year ended December 31, 2006 compared to the same period in 2005 due primarily to the lower amortization of gains associated with disposition of SO2 allowances and the expiration of the amortization associated with the disposition of property offset slightly by higher interest income. NPC's Other income slightly increased for the year ended December 31, 2005 compared to the same period in 2004 due to higher interest income offset by lower amortization of gains associated with disposition of SO2 allowances.

NPC's Other expense was comparable for 2006 to 2005. NPC's Other expense increased for the year ended December 31, 2005 compared to the same period in 2004 due primarily to higher expenses associated with corporate advertising, lobbying activities and various other charges, all of which were not individually significant.

ANALYSIS OF CASH FLOWS

NPC's cash flows increased during the year ended December 31, 2006 compared to the same period in 2005 due to an increase in cash from financing activities, a slight increase in cash from operating activities offset partially by an increase in use of cash by investing activities.

At various times during 2006, NPC borrowed a total of $710 million under its revolving credit facility and repaid a total of $860 million, including $150 million borrowed in 2005, using the net proceeds of issuance of $905 million of NPC's General and Refunding Mortgage Notes, Series M, N and O, and a $200 million capital contribution from SPR. The remainder of the proceeds, together with the draw on the credit facility and cash from operations, was utilized to redeem approximately $563 million of outstanding debt and to pay associated costs and to finance net construction costs of $627 million. NPC also refinanced $92.5 million of Revenue Bonds with newly issued auction rate Revenue Bonds during 2006. In 2006, SPR contributed capital of $200 million to NPC, and NPC paid dividends to SPR of approximately $35.8 million.

Cash used by investing activities increased in 2006 when compared to 2005 primarily due to the acquisition of Silverhawk and improvements at other generating stations, offset by a reduction in spending at the Lenzie plant that was placed in service in 2006.

Cash from operations increased during 2006 when compared to 2005 due to rate increases for deferred energy and a decrease in accounts receivable, offset by a decrease in collections for deferred energy balances due to the ending of collection periods and a reduction in accounts payable primarily associated with purchase power suppliers. The increase was also offset by the settlement with Enron.

NPC's cash flows decreased during the year ended December 31, 2005 compared to the same period in 2004, as a result of an increase in cash used for investing activities and by decreases in cash flows from operating and financing activities. Cash used in investing activities increased mainly due to an increase in utility construction for the Chuck Lenzie project under construction in 2005. The decrease in cash from operating activities is primarily due to energy costs being higher than amounts recovered in rates in 2005 and changes in accounts receivable for tax sharing agreements. Also partially offsetting the decrease in cash from operating activities was the $49 million escrow payment for Enron in 2004, and a reduction in prepayments and deposits for energy in 2005 due to the establishment of the revolving credit facility. Cash from financing activities decreased in 2005 due to a reduction in debt issued in 2005 offset by additional investments from the parent company and lower dividend payments. NPC was able to retire $210 million of high yield notes in the third quarter utilizing the majority of a $230 million equity contribution from SPR, per the equity claw-back provisions of the note.

LIQUIDITY AND CAPITAL RESOURCES

Overall Liquidity

NPC's primary source of operating cash flows is electric revenues, including the recovery of previously deferred energy costs. Significant uses of cash flows from operations include the purchase of electricity and natural gas, other operating expenses and the payment of interest on NPC's outstanding indebtedness.

Available Liquidity as of December 31, 2006

(in millions)	NPC
Cash and cash equivalents	**$ 36.6**
Balance available on revolving credit facility	**545.0**
Total available liquidity[1]	**$581.6**

(1) As of February 23, 2007, NPC had approximately $476.3 million available under its revolving credit facility.

In August 2006, SPR contributed capital to NPC of approximately $200 million. NPC used the proceeds to repay indebtedness under its revolving credit facility. There were no other capital contributions from SPR to NPC in 2006.

In 2006, NPC paid $35.8 million in dividends to SPR and declared an additional $13.5 million dividend. In January 2007, NPC paid the $13.5 million dividend to SPR.

NPC anticipates that it will be able to meet operating costs, such as fuel and purchased power costs, with internally generated funds, including the recovery of deferred energy and external borrowings. However, to fund capital requirements, as discussed below, NPC may be required to meet such financial obligations with a combination of internally generated funds, the use of its revolving credit facility and, if necessary, the issuance of long-term debt. Additional liquidity beyond the amount indicated in the footnote above would come from a capital contribution from SPR, or through additional financing authority granted by an order of the PUCN, requested through the submittal of a financing application.

NPC's overall liquidity continued to improve in 2006. NPC's revolving credit facility was increased to $600 million in April 2006, providing $100 million of additional liquidity for increased commodity prices. NPC's debt profile improved as a result of refinancing more than $668 million of long-term debt. These refinancings are expected to reduce future interest expense.

NPC designs operating and capital budgets to control operating costs and capital expenditures. In addition to operating expenses, NPC has continuing commitments for capital expenditures for construction, improvement and maintenance of facilities.

Detailed below are NPC's Capital Structure, Capital Requirements, Contractual Obligations, recently completed Financing Transactions and Factors Affecting Liquidity including our ability to obtain debt on favorable terms and limitations on indebtedness.

Capital Structure

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

	2006		2005	
Current maturities of long-term debt	**$ 5,948**	**0.1%**	$ 6,509	0.2%
Long-term debt	**2,380,139**	**52.2%**	2,214,063	55.6%
Common equity	**2,172,198**	**47.7%**	1,762,089	44.2%
Total	**$4,558,285**	**100%**	$3,982,661	100%

Capital Requirements

CONSTRUCTION EXPENDITURES NPC's cash construction expenditures have increased since 2004 and are expected to continue to increase due to programs designed to meet electric load growth and reliability needs. Cash construction expenditures for the years ended 2006, 2005 and 2004 were approximately $627.0 million, $478 million and $454 million, respectively. NPC's cash requirement for construction expenditures for 2007 are projected to be $980.1 million. NPC's cash requirement for construction expenditures for 2007 through 2011 are projected to be $5.9 billion. To fund these capital projects NPC may meet such financial obligations with a combination of internally generated funds, the use of its revolving credit facility, the issuance of long-term debt and, if necessary, capital contributions from SPR. Depending on the progress of the Ely Energy Center, the timing and extent of the estimated capital expenditures necessary may change.

CONTRACTUAL OBLIGATIONS The table below provides NPC's consolidated contractual obligations, not including estimated construction expenditures described above, as of December 31, 2006 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						
	2007	2008	2009	2010	2011	Thereafter	Total
Long-term debt maturities	$ 5,948	$ 7,068	$ 22,138	$ 7,843	$369,734	$1,986,113	$2,398,844
Long-term debt interest payments	153,962	154,367	154,228	153,812	136,782	1,261,214	2,014,365
Purchased power	310,988	257,739	239,361	244,305	242,671	2,868,242	4,163,306
Coal and natural gas	250,201	62,833	50,075	47,107	34,438	183,550	628,204
Long-term service agreements[1]	15,979	13,867	24,267	22,037	12,148	123,783	212,081
Southern operations center lease	875	3,000	3,075	3,180	3,260	65,320	78,710
Operating leases	6,525	7,146	6,253	5,161	3,441	64,459	92,985
Total contractual cash obligations	$744,478	$506,020	$499,397	$483,445	$802,474	$6,552,681	$9,588,495

(1) Does not include equipment and services contracts related to the new peaking units at Clark Generating Station, entered into in February 2007.

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 is expected to decrease in 2007 by approximately $1.3 million compared to the 2006 cost of $30.6 million. As of September 30, 2006, the measurement date, the plan was fully funded on a FAS 87 ABO basis (fair value of assets exceeded ABO). During 2006, SPR contributed a total of $16 million to meet its funding obligations under the plan. At the present time it is not expected that any additional funding will be required in 2007 to meet the minimum funding level requirements defined by the Pension Benefit Guaranty Corporation and ERISA. However, SPR and the Utilities currently expect to contribute an amount similar to the 2006 funding. The amounts to be contributed may change subject to market conditions.

Financing Transactions

POLLUTION CONTROL REFUNDING REVENUE BONDS, SERIES 2006, 2006A AND 2006B In August 2006, on behalf of NPC, Clark County, Nevada (Clark County), issued $39.5 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006, due January 2036. On the same date, on behalf of NPC, Coconino County, Arizona Pollution Control Corporation (Coconino County), issued $40 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006A, due September 2032, and $13 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006B, due March 2039.

In connection with the issuance of these Bonds, NPC entered into financing agreements with Clark County and Coconino County, pursuant to which Clark County and Coconino County loaned the proceeds from the sales of the bonds to NPC. NPC's payment obligations under the financing agreements are secured by NPC's General and Refunding Mortgage Notes, Series P.

The interest rates of the Bonds were initially determined by an auction. The method of determining the interest rate on the Bonds may be converted from time to time so that such Bonds would thereafter bear interest at a daily, weekly, flexible, auction or term rate as designated.

The proceeds of the offerings were used to refund the following bonds, all of which were previously issued for the benefit of NPC:

- $39.5 million principal amount of 6.60% Clark County's Pollution Control Refunding Revenue Bonds, Series 1992B,
- $20 million principal amount of 6.375% Coconino County's Pollution Control Revenue Bonds, Series 1996,
- $20 million principal amount of 5.80% Coconino County's Pollution Control Revenue Bonds, Series 1997B, and
- $13 million principal amount of 5.35% Coconino County's Pollution Control Refunding Revenue Bonds, Series 1995E.

GENERAL AND REFUNDING MORTGAGE NOTES, SERIES O On May 12, 2006, NPC issued and sold $250 million in aggregate principal amount of 6.5% General and Refunding Mortgage Notes, Series O, due 2018. The Series O Notes were issued with registration rights. Proceeds of the offering, together with available cash, were utilized to:

- fund the early redemption of $78 million aggregate principal amounts of NPC's 7.2% Industrial Development Revenue Bonds, Series 1992C, due 2022,
- fund the early redemption, in June 2006, of approximately $72.2 million aggregate principal amount of NPC's 7.75% Junior Subordinated Debentures due 2038 (when the Debentures were repaid upon redemption, the proceeds from the repayment were used to simultaneously redeem an equal amount of the 7.75% Cumulative Quarterly Preferred Securities of NVP Capital III, a wholly-owned subsidiary of NPC),
- repay amounts outstanding under NPC's revolving credit facility.

In June 2006, NPC issued an additional $75 million in aggregate principal amount of its 6.5% General and Refunding Mortgage Notes, Series O, as part of the same series as the original Series O Notes. The aggregate principal amount of 6.5% General and Refunding Mortgage Notes, Series O, due 2018, outstanding is $325 million as of December 31, 2006. The proceeds from the second issuance, along with the proceeds from an offering of $120 million of NPC's 6.65% General and Refunding Mortgage Notes, Series N, due 2036 (described below) were used to pay the total consideration for the tender offer for the 10.875% General and Refunding Mortgage Notes, Series E, described below.

GENERAL AND REFUNDING MORTGAGE NOTES, SERIES N In April 2006, NPC issued and sold $250 million of its 6.65% General and Refunding Mortgage Notes, Series N, due April 2036. The Series N Notes were issued with registration rights. Proceeds of the offering, together with available cash, were utilized to:

- fund the early redemption of $35 million aggregate principal amount of NPC's 8.50% Series Z First Mortgage Bonds due 2023 plus approximately $1 million of associated redemption premiums,
- fund the early redemption of $105 million aggregate principal amount of 6.70% Industrial Development Revenue Bonds, due 2022, and
- fund the early redemption of approximately $122.5 million aggregate principal amount of NPC's 8.20% Junior Subordinated Debentures due 2037 (when the debentures were repaid upon redemption, the proceeds from the repayment were used to simultaneously redeem an equal amount of the 8.20% Cumulative Quarterly Preferred Securities of NVP Capital I, a wholly-owned subsidiary of NPC).

In June 2006, NPC issued an additional $120 million in aggregate principal amount of its 6.65% General and Refunding Mortgage Notes, Series N, as part of the same series as the original Series N Notes. The aggregate principal amount of 6.65% General and Refunding Mortgage Notes, Series N, due 2036, outstanding is $370 million as of December 31, 2006. The proceeds from the second issuance, along with the proceeds from an offering of $75 million of NPC's 6.5% General and Refunding Mortgage Notes, Series O, due 2018 (described above) were used to pay the total consideration for the tender offer on the 10.875% General and Refunding Mortgage Notes, Series E, described below.

TENDER OFFER FOR GENERAL AND REFUNDING MORTGAGE NOTES, SERIES E In June 2006, NPC commenced a tender offer for all of its 10.875% General and Refunding Mortgage Notes, Series E, due 2009. In conjunction with that offer, NPC solicited the consent of holders of a majority in aggregate principal amount of the Series E Notes to eliminate substantially all of the restrictive covenants contained in the officer's certificate governing the Series E Notes. Approximately $150 million of $162.5 million Series E Notes outstanding were validly tendered and accepted by NPC. Those holders who tendered the Series E Notes and delivered their consents by June 2006 were entitled to receive a consent payment of $30 per $1,000 principal amount of Series E Notes, plus tender consideration for each $1,000 principal amount of Series E Notes validly tendered. Those holders who tendered the Series E Notes after June 14, 2006, but prior to June 28, 2006, were entitled to receive the tender consideration only. This tender consideration was $1,038.45 in cash plus accrued and unpaid interest up to the June 2006 settlement date per $1,000 principal amount of the Series E Notes tendered. Proceeds from the June 2006 issuance of Series N and Series O Notes (discussed above) were used to fund the tender offer. The total consideration (including the consent payment and accrued interest) paid in June 2006 was approximately $163.6 million. In October 2006, NPC redeemed the remaining $12.6 million aggregate principal amount of the Series E Notes, plus accrued interest, using available cash on hand.

REVOLVING CREDIT FACILITY In April 2006, NPC increased the size of its second amended and restated revolving credit facility expiring 2010 to $600 million. The facility will provide additional liquidity for increased commodity prices and temporary bridge financing of capital expenditures. As of December 31, 2006, NPC had $55 million of letters of credit outstanding and had no amounts borrowed under the revolving credit facility. As of February 23, 2007, NPC had $48.7 million of letters of credit outstanding and $75 million borrowed under the revolving credit facility.

The NPC Credit Agreement contains two financial maintenance covenants. The first requires NPC to maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires NPC to maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1. As of December 31, 2006, NPC was in compliance with these covenants.

The NPC Credit Agreement provides for an event of default if there is a failure under NPC's other financing agreements to meet certain payment terms or to observe other covenants that would result in an acceleration of payments due.

The NPC Credit Agreement places certain restrictions on debt incurrence, liens and dividends. These restrictions are discussed in Note 8, Debt Covenant and Other Restrictions.

GENERAL AND REFUNDING MORTGAGE NOTES, SERIES M In January 2006, NPC issued and sold $210 million of its 5.95% General and Refunding Mortgage Notes, Series M, due March 2016. The Series M Notes were issued with registration rights. In February 2006 the net proceeds of the issuance plus available cash were used to repay $210 million of amounts outstanding under NPC's revolving credit facility, which were borrowed to finance the purchase of a 75% ownership interest in the Silverhawk Generating Facility.

DISCHARGE OF NPC'S FIRST MORTGAGE INDENTURE In August 2006, following the refunding of the $39.5 million aggregate principal amount of Pollution Control Refunding Revenue Bonds (PCRBs), Series 1992B, (see above) the first mortgage bonds which secured the PCRBs were retired.

In August 2006, NPC exchanged $115 million in aggregate principal amount of First Mortgage Bonds, Series BB and Series CC, for $115 million in aggregate principal amount of General and Refunding Mortgage Bonds, Series Q. The first mortgage bonds had been issued as security for the $100 million Clark County, Nevada, Industrial Development Refunding Revenue Bonds, Series 2000A, and the $15 million Clark County, Nevada, Pollution Control Refunding Revenue Bonds, Series 2000B.

With the conclusion of these two transactions, all of the bonds outstanding under the First Mortgage Indenture were retired as of August 2006. Upon the satisfaction and discharge of the First Mortgage Indenture in September 2006, NPC's General and Refunding Mortgage Indenture, dated as of May 1, 2001, with the Bank of New York as Trustee, became the first priority lien on substantially all of NPC's utility property in Nevada.

Factors Affecting Liquidity

LIMITATIONS ON INDEBTEDNESS Certain factors impact NPC's ability to issue debt:

1. Financing Authority from the PUCN. In February 2006, NPC received PUCN authorization to enter into financings of $1.78 billion, which amount included $600 million for the revolving credit facility (described above). NPC has issued approximately $100 million of the new debt authorized under the PUCN Order. NPC's only remaining authority under this PUCN Order allows NPC to refinance its existing debt and to use its $600 million revolving credit facility.
2. Limits on Bondable Property. To the extent that NPC has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, NPC's ability to issue secured debt is still limited by the amount of bondable property or retired bonds that can be used to issue debt under its General and Refunding Mortgage Indenture. As of December 31, 2006, NPC had the capacity to issue $672 million of General and Refunding Mortgage Securities.
3. Financial Covenants in its and SPR's financing agreements. The terms of certain SPR debt further prohibit NPC and SPPC from incurring additional indebtedness unless certain conditions have been met. See SPR's Limitations on Indebtedness for details of these restrictions. In addition to the SPR debt, the terms of NPC's Series G Notes, which mature in 2013, NPC's Series I Notes, which mature in 2012, NPC's Series L Notes, which mature in 2015, and NPC's Second Amended and Restated Revolving Credit Facility restrict NPC from incurring any additional indebtedness unless certain covenants are satisfied (See Note 8, Debt Covenant and Other Restrictions). If NPC's Series G Notes, Series I Notes, or the Series L Notes are upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable series of securities remains investment grade.

   As of December 31, 2006, the financial covenants under the revolving credit facility, which are more restrictive than the Series G, I and L Notes restrictions, would allow NPC to issue up to $2.1 billion of additional debt. The covenant limitations of certain SPR debt place a cap on additional indebtedness, on a consolidated basis, including SPPC and NPC, of $2.1 billion as of December 31, 2006. However, since NPC currently has no PUCN authority to issue new debt, NPC is limited to borrowing under its credit facility. As of February 23, 2007, the balance available under the credit facility is $476.3 million.

   Since SPR's debt covenant limitations are calculated on a consolidated basis, SPR's debt covenant limitations may allow for higher or lower borrowings than $2.1 billion, depending on the Utilities' combined usage of their respective revolving credit facilities at the time of the covenant calculation.

LIMITATIONS ON ABILITY TO ISSUE GENERAL AND REFUNDING MORTGAGE BONDS As of December 31, 2006, $2.7 billion of NPC's General and Refunding Mortgage Securities were outstanding. As mentioned in (2) above under "Limitations on Indebtedness," additional securities may be issued under the General and Refunding Mortgage Indenture as of December 31, 2006. That amount is determined on the basis of:

1. 70% of net utility property additions
2. the principal amount of retired General and Refunding Mortgage Securities, and/or
3. the principal amount of first mortgage bonds retired after October 2001.

NPC also has the ability to release property from the lien of the General and Refunding Mortgage Indenture 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 securities issuable under that indenture.

CREDIT RATINGS NPC is rated by four Nationally Recognized Statistical Rating Organizations, S&P, Moody's, Fitch and DBRS. As of February 23, 2007, the ratings are as follows:

		Rating Agency			
		DBRS	Fitch	Moody's	S&P
NPC	Sr. secured debt	BBB (low)*	BBB-*	Ba1	BB+
NPC	Sr. unsecured debt	Not rated	BB	Not rated	B

** Ratings are investment grade*

In February 2007, DBRS, who had not previously issued ratings on the NPC, assigned new ratings to NPC's senior secured debt. The rating is BBB (low), which is the minimum level for investment grade. DBRS's trend for NPC is Stable.

In 2006, there were other changes to the ratings of NPC's debt. Fitch upgraded the ratings for NPC's senior secured debt to BBB-, the minimum level for investment grade. The senior unsecured debt for NPC was upgraded from BB- to BB, which is still non-investment grade. Fitch revised the rating outlook for NPC from Positive to Stable. S&P upgraded the ratings of NPC's senior secured debt from BB to BB+, one level below investment grade. Moody's re-affirmed its ratings for NPC's senior secured debt at Ba1, one level below investment grade.

A security rating is not a recommendation to buy, sell or hold securities. Security ratings are subject to revision and withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating.

ENERGY SUPPLIER ISSUES With respect to NPC's contracts for purchased power, NPC purchases and sell electricity with counterparties under the Western Systems Power Pool (WSPP) agreement, an industry standard contract that NPC is 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 request adequate financial assurance, which, if not provided within three 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 three 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 December 31, 2006 for all suppliers continuing to provide power under a WSPP agreement would approximate a $55.8 million payment by NPC. These contracts qualify for the normal purchases scope exception of SFAS No. 133, and as such, are not required to be marked to market on the balance sheet. Refer to Note 9, Derivatives and Hedging Activities, of the Notes to Financial Statements for further discussion.

GAS SUPPLIER ISSUES With respect to the purchase and sale of natural gas, NPC uses several types of standard industry contracts. 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. Because of creditworthiness concerns, most contracts and confirmations for natural gas purchases have been modified or separate agreements have been made to either shorten the normal payment due date or require payment in advance of delivery. At the present time, four counterparties require payment in advance of delivery.

Gas transmission service is secured under FERC Tariffs or custom agreements. These service contracts and Tariffs require the user establish and maintain creditworthiness to obtain service or otherwise post cash or a letter of credit to be able to receive service. Service contracts are subject to FERC approved tariffs, which, under certain circumstances, require the Utility to provide collateral to continue receiving service. To date, a letter of credit has been provided to one of NPC's gas transporters.

CROSS-DEFAULT PROVISIONS None of the financing agreements of NPC contain a cross-default provision that would result in an event of default by NPC upon an event of default by SPR or SPPC under any of its financing agreements. In addition, certain financing agreements of NPC provide for an event of default if there is a failure under other financing agreements of NPC 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 such other indebtedness when due) provide for a cure period of 30-60 days from the occurrence of a specified event during which time NPC may rectify or correct the situation before it becomes an event of default.

SIERRA PACIFIC POWER COMPANY

RESULTS OF OPERATIONS

SPPC recognized net income of $57.7 million for the year ended December 31, 2006 compared to net income of $52.1 million in 2005 and a net income of $18.6 million in 2004. SPPC's operating results for 2005 improved over 2004 primarily by the absence of the $47 million charge associated with the Piñon Pine power plant project, consisting of an approximate $43 million disallowance and a $4 million impairment charge. In January 2006, the Second Judicial District Court of the State of Nevada vacated and remanded back to the PUCN for further review as to whether the costs associated with the Piñon Pine power plant project were justly and reasonably incurred. The case remains at the PUCN for review. See Note 13, Commitments and Contingencies for further discussion of the case.

In 2006, SPPC paid $17.9 million in dividends to SPR and declared an additional $6.7 million dividend. In January 2007, SPPC paid the $6.7 million dividend to SPR. In 2005, SPPC declared and paid $23.9 million in common dividends to its parent SPR and declared and paid $3.9 million in dividends to holders of its preferred stock.

Gross margin is presented by SPPC in order to provide information by segment that management believes aids the reader in determining how profitable the electric and gas businesses are at the most fundamental level. Gross margin, which is a "non-GAAP financial measure" as defined in accordance with SEC rules, provides a measure of income available to support the other operating expenses of the business and is utilized by management in its analysis of its business.

SPPC believes presenting gross margin allows the reader to assess the impact of SPPC's regulatory treatment and its overall regulatory environment on a consistent basis. Gross margin, as a percentage of revenue, is primarily impacted by the fluctuations in regulated electric and natural gas supply costs versus the fixed rates collected from customers. While these fluctuating costs impact gross margin as a percentage of revenue, they only impact gross margin amounts if the costs cannot be passed through to customers. Gross margin, which SPPC calculates as operating revenues less fuel and purchased power costs, provides a measure of income available to support the other operating expenses of SPPC. Gross margin changes based on such factors as general base rate adjustments (which are required to be filed by statute every two years) and reflect SPPC's strategy to increase internal power generation versus purchased power, which generates no gross margin.

The components of gross margin for the years ended December 31 (dollars in thousands):

Year ended December 31,	**2006**	**Change from Prior Year**	2005	Change from Prior Year	2004
Operating Revenues:					
Electric	**$1,020,162**	**5.5%**	$ 967,427	9.7%	$ 881,908
Gas	**210,068**	**17.8%**	178,270	15.9%	153,752
	$1,230,230	**7.4%**	$1,145,697	10.6%	$1,035,660
Energy Costs:					
Purchased power	**$ 344,590**	**-2.1%**	$ 352,098	15.5%	$ 304,955
Fuel for power generation	**247,626**	**6.0%**	233,653	4.3%	224,074
Gas purchase for resale	**160,739**	**14.1%**	140,850	15.9%	121,526
Deferral of energy costs—electric—net	**47,043**	**480.1%**	8,110	14.9%	7,060
Deferral of energy costs—gas—net	**6,947**	**-1027.5%**	(749)	-81.9%	(4,136)
	$ 806,945	**9.9%**	$ 733,962	12.3%	$ 653,479
Energy Costs by Segment:					
Electric	**$ 639,259**	**7.6%**	$ 593,861	10.8%	$ 536,089
Gas	**167,686**	**19.7%**	140,101	19.3%	117,390
	$ 806,945	**9.9%**	$ 733,962	12.3%	$ 653,479
Gross Margin by Segment:					
Electric	**$ 380,903**	**2.0%**	$ 373,566	8.0%	$ 345,819
Gas	**42,382**	**11.0%**	38,169	5.0%	36,362
	$ 423,285	**2.8%**	$ 411,735	7.7%	$ 382,181

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

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Electric Operating Revenues:					
Residential	**$ 319,140**	**12.9%**	$282,655	13.4%	$249,287
Commercial	**370,617**	**13.9%**	325,456	10.3%	294,956
Industrial	**299,163**	**-10.3%**	333,621	12.8%	295,882
Retail revenues	**988,920**	**5.0%**	941,732	12.1%	840,125
Other	**31,242**	**21.6%**	25,695	-38.5%	41,783
Total revenues	**$1,020,162**	**5.5%**	$967,427	9.7%	$881,908
Retail sales in thousands of megawatt-hours (MWh)	**8,711**	**-5.7%**	9,234	1.0%	9,143
Average retail revenue per MWh	**$ 113.53**	**11.3%**	$ 101.99	11.0%	$ 91.89

SPPC's retail revenues increased in 2006 as compared to 2005 primarily due to increases in retail rates and to a lesser extent customer growth. Retail rates increased as a result of SPPC's various BTER and deferred energy cases. (Refer to "Regulatory Proceedings.") The number of residential, commercial and industrial customers increased (2.8%, 3.0% and 2.1%, respectively). These increases were offset by lower industrial energy revenues and MWhs as a result of SPPC's large industrial customer, Barrick Gold, moving to distribution-only services effective December 1, 2005.

On December 1, 2006, SPPC filed its annual deferred energy filing and an application to request recovery of deferred legal and settlement costs incurred for terminated power contracts executed during the Western Energy Crisis. If approved by the PUCN, the overall effect of both filings would be a slight decrease in rates. SPPC requested that the rates become effective on July 1, 2007. For further discussion on the various cases, see Regulatory Proceedings, later.

SPPC's retail revenues increased in 2005 as compared to 2004 due to increased rates and customer growth. Customer rates for Nevada increased due to SPPC's 2003 General Rate Case and various deferred energy and BTER energy cases and an increase in California customer rates effective December 1, 2004 and September 1, 2005. For further discussion of rate cases see Note 3, Regulatory Actions, of Notes to Financial Statements. Growth in residential and commercial customers (3.1% and 3.5%, respectively) also contributed to the increase. Additionally, contributing to the increase was the recognition in December 2005 of $12 million in DEAA revenues as a result of Barrick's transition to distribution only services effective December 1, 2005, offset by lower BTER revenues.

The increase in Electric Operating Revenues—Other in 2006 compared to 2005 was primarily due to the amortization of impact charges and increased wheeling revenues resulting from Barrick becoming a distribution-only services customer.

The decrease in Electric Operating Revenues—Other in 2005 compared to 2004 was primarily due to certain types of transactions that were reported in revenues for 2004 which are now being netted in purchased power.

Gas Operating Revenue

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Gas Operating Revenues:					
Residential	**$120,734**	**25.4%**	$ 96,292	18.5%	$ 81,262
Commercial	**54,316**	**22.6%**	44,286	13.5%	39,019
Industrial	**20,509**	**21.0%**	16,953	37.4%	12,336
Retail revenues	**195,559**	**24.1%**	157,531	18.8%	132,617
Wholesale	**11,650**	**-34.5%**	17,786	-1.9%	18,122
Miscellaneous	**2,859**	**-3.2%**	2,953	-2.0%	3,013
Total revenues	**$210,068**	**17.8%**	$178,270	15.9%	$153,752
Retail sales in thousands of decatherms	**15,058**	**1.6%**	14,819	6.6%	13,896
Average retail revenues per decatherm	**$ 12.99**	**22.2%**	$ 10.63	11.4%	$ 9.54

SPPC's retail gas revenues increased in 2006 compared to 2005 primarily due to increases in customer rates and customer growth. Retail rates increased as a result of SPPC's various general, energy and deferred energy rate cases (refer to "Regulatory Proceedings"). The number of residential, commercial and industrial customers increased (4.3%, 3.7% and 16.7%, respectively).

SPPC's retail gas revenues increased in 2005 compared to 2004 primarily due to increases in Nevada customer rates, customer growth and weather. Customer rates increased as a result of SPPC's Purchased Gas Adjustment filings effective November 2004, and SPPC's Gas Deferred Energy Rate Case and BTER Update effective November 2005 (refer to Note 3, Regulatory Actions, of Notes to Financial Statements). Customer growth increased as a result of an increase in the number of residential, commercial, and industrial customers (4.3%, 3.5% and 15.9%, respectively). Weather contributed to the increase in revenues with colder temperatures in the winter and spring, partially offset by warmer temperatures in the fall.

The wholesale revenues for 2006 decreased compared to prior year 2005 primarily due to decreased availability of gas for wholesale sales.

Wholesale and miscellaneous gas revenues for 2005 were consistent with the prior year.

Purchased Power

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Purchased Power	**$344,590**	**-2.1%**	$352,098	15.5%	$304,955
Purchased power in thousands of MWh	**5,334**	**-2.0%**	$ 5,441	-4.9%	$ 5,719
Average cost per MWh of purchased power	**$ 64.60**	**-0.2%**	$ 64.71	21.4%	$ 53.32

SPPC's purchased power costs decreased in 2006 compared to 2005 primarily due to a decrease in volume associated with the loss of Barrick, which transitioned to distribution only services.

Purchased power costs increased in 2005 compared to 2004, due to higher prices. SPPC's energy contracts calculate prices using gas indexes; therefore, higher natural gas prices in 2005 increased the price of purchased power. Overall volumes for 2005 were lower than 2004 due to certain types of transactions that were reported in revenues for 2004 which are now being netted in purchased power and because purchases associated with risk management activities, which are included in purchased power, decreased in 2005.

Fuel for Power Generation

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Fuel for Power Generation	**$247,626**	**6.0%**	$233,653	4.3%	$224,074
Thousands of MWh generated	**4,059**	**-7.3%**	$ 4,379	-4.9%	$ 4,605
Average fuel cost per MWh of generated power	**$ 61.01**	**14.3%**	$ 53.36	9.7%	$ 48.66

Fuel for power generation and the average fuel cost per MWh increased in 2006 compared to 2005. The increase is primarily due to hedging instruments which were purchased during the period when gas prices were escalating as a result of the 2005 hurricanes in the southern United States. The settlement of these instruments negatively impacted the average cost per MWh as natural gas prices were decreasing in 2006. The settlements of hedging instruments in the fourth quarter of 2005 partially offset the gas cost in 2005. MWh generated decreased as compared to 2005 primarily due to Barrick, which transitioned to distribution-only service in 2006.

Fuel for power generation costs increased in 2005 as compared to 2004 due to increases in natural gas and coal prices. However, the natural gas cost increases were partially offset by SPPC's hedging strategies, as discussed in Energy Supply (Utilities). The decrease in the volume of generation was primarily due to SPPC relying more on purchased power to satisfy its native load requirements.

Gas Purchased for Resale

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Gas Purchased for Resale	**$160,739**	**14.1%**	$140,850	15.9%	$121,526
Gas purchased for resale (in thousands of decatherms)	**17,491**	**5.4%**	$ 16,592	-6.1%	$ 17,673
Average cost per decatherm	**$ 9.19**	**8.2%**	$ 8.49	23.4%	$ 6.88

The cost of gas purchased for resale and average cost per decatherm increased in 2006 as compared to 2005. The increase is primarily due to hedging instruments which were purchased during the period when gas prices were escalating as a result of the 2005 hurricanes in the southern United States. The settlement of these instruments negatively impacted the average cost per decatherm as natural gas prices were decreasing in 2006. The volume of gas purchased for resale increased primarily due to the colder winter weather during the fourth quarter of 2006.

The cost of gas purchased for resale increased in 2005 as compared to 2004 due to increases in natural gas prices. The volume of gas purchased for resale decreased during this period due to the fuel forecast more closely matching usage, leaving less fuel available for wholesale sales. This decrease in volume of gas was partially offset by the increase in demand for gas for resale during the first two quarters of 2005 due to colder winter weather.

Deferral of Energy Costs—Net

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Deferred energy costs—electric—net	**$47,043**	**N/A**	$ 8,110	14.9%	$ 7,060
Deferred energy costs—gas—net	**6,947**	**N/A**	(749)	-81.9%	(4,136)
Total	**$53,990**		$ 7,361		$ 2,924

Deferred energy costs—net represents the difference between actual fuel and purchased power costs incurred during the period and amounts recoverable through current rates. To the extent actual costs exceed amounts recoverable through current rates the excess is recognized as a reduction in costs. Conversely, to the extent actual costs are less than amounts recoverable through current rates the difference is recognized as an increase in costs. Deferred energy costs—net also includes the current amortization of fuel and purchased power costs previously deferred.

Deferred energy costs—electric—net for 2006, 2005 and 2004 reflect amortization of deferred energy costs of $46.3 million, $56.7 million and $37.0 million, respectively; and an over-collection of amounts recoverable in rates of $0.7 million in 2006 and an under-collection of $48.6 million and $29.9 million in 2005 and 2004, respectively. See Note 1, Summary of Significant Accounting Policies, Deferral of Energy Costs, of Notes to Financial Statements for further detail of deferred energy balances.

Deferred energy costs—gas—net for 2006, 2005 and 2004 reflect amortization of deferred energy costs of $6.3 million, $1.5 million and $3.3 million, respectively; and an over-collection of amounts recoverable in rates of $0.6 million in 2006 and an under-collection in 2005 and 2004 of $2.3 million and $7.4 million, respectively.

Allowance for Funds Used During Construction (AFUDC)

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Allowance for other funds used during construction	**$ 6,471**	**294.8%**	$ 1,639	-4.6%	$ 1,718
Allowance for borrowed funds used during construction	**5,505**	**266.0%**	$ 1,504	-47.2%	$ 2,849
	$11,976	**281.0%**	$ 3,143	-31.2%	$ 4,567

AFUDC for SPPC is higher in 2006 compared to 2005 due to an increase in the average Construction Work-In-Progress (CWIP) balance on which AFUDC is calculated due to the expansion of the Tracy Generating Station which started in late 2005.

AFUDC is lower in 2005 compared to 2004 due to a decrease in the average CWIP balance, primary as a result from the completion in May 2004 of the 3-year Falcon-Gonder 345KV Transmission Line project.

Other (Income) and Expenses

	2006		2005		2004
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Other operating expense	**$141,350**	**7.2%**	$131,901	3.0%	$128,091
Maintenance expense	**$ 31,273**	**17.2%**	$ 26,690	22.0%	$ 21,877
Depreciation and amortization	**$ 87,279**	**-3.6%**	$ 90,569	4.3%	$ 86,806
Interest charges on long-term debt	**$ 71,869**	**3.8%**	$ 69,240	-2.9%	$ 71,312
Interest for energy suppliers	**$ —**	**N/A**	$ (2,396)	-78.2%	$ (10,999)
Interest charges—other	**$ 5,142**	**38.0%**	$ 3,727	-30.6%	$ 5,367
Interest accrued on deferred energy	**$ (5,996)**	**-15.5%**	$ (7,092)	38.2%	$ (5,133)
Other income	**$ (9,412)**	**58.5%**	$ (5,940)	74.4%	$ (3,406)
Disallowed merger costs	**$ —**	**N/A**	$ —	N/A	$ 1,929
Plant costs disallowed	**$ —**	**N/A**	$ —	N/A	$ 47,092
Other expense	**$ 8,422**	**12.4%**	$ 7,493	30.9%	$ 5,726

Other operating expense increased for 2006 compared to 2005 due to increased amortization of regulatory assets resulting from SPPC's GRC, as discussed in Regulatory Proceedings. Also contributing to the increase was the recovery in 2005 of a claim against Pacific Gas and Electric, partially offset by Enron legal fees incurred in 2005.

Other operating expense increased for 2005 compared to 2004 primarily due to severance costs associated with the reorganization of SPPC, NPC and SPR.

The increase in Maintenance expense for 2006 compared to 2005 is primarily due to higher costs for scheduled maintenance and forced outages in 2006 at Ft. Churchill and Valmy, partially offset by a 2006 planned major outage at Tracy that was rescheduled to 2007.

The increase in Maintenance expense for 2005 compared to 2004 is primarily due to the timing of scheduled and unscheduled plant maintenance at Valmy.

Depreciation and amortization were lower in 2006 than 2005 due to the change in depreciation rates as ordered by PUCN in SPPC's General Electric and Gas Rate Case. For further information on SPPC's General and Electric Rate Case, see Regulatory Proceedings, later.

Depreciation and amortization were higher in 2005 than 2004 due to an increase in plant-in-service from regular system growth.

SPPC's interest charges on Long-Term Debt for the year ended December 31, 2006 increased from 2005 due primarily to interest on the $300 million Series M Notes issued in March 2006, partially offset by debt redemptions in 2006 of $188 million and the refinancing of $268 million of tax exempt debt from fixed rate to variable in November 2006. SPPC's interest charges on Long-Term Debt for the year ended December 31, 2005 decreased from 2004 as a result of the reduction in interest rate during 2004 associated with the replacement of its 10.5% $100 million term loan facility with 6.25% $100 million Series H Notes, and a reduction in interest rate in April 2004 of SPPC's $80 million Washoe Water Bonds from 7.5% to 5.0%. See Note 6, Long-Term Debt, of the Notes to Financial Statements for additional information regarding long-term debt.

SPPC's interest charges for energy suppliers for the year ended December 31, 2005 reflects the reversal of interest of $3.2 million resulting from the November 2005 settlement agreement between the Utilities and Enron. SPPC's Interest charges for energy suppliers for the year ended December 31, 2004 reflects the reversal of interest of $12.3 million resulting from a December 2004 ruling by the U.S. District Court that lowered the interest rate previously accrued. See Note 13, Commitments and Contingencies, of the Notes to Financial Statements for more information regarding the Enron litigation.

SPPC's interest charges—other for the year ended December 31, 2006 increased compared to the same period in 2005 primarily due to higher amortization of debt issuance costs related to new debt issuances. See Financing Transactions. SPPC's Interest charges-other for the year ended December 31, 2005 decreased compared to the same period in 2004 due primarily to the absence of charges related to the accounts receivable facility and short-term debt.

SPPC's interest accrued on deferred energy costs for the year ended December 31, 2006 was lower than the same period in 2005 due primarily to lower deferred energy balances during 2006 when compared to the same period in 2005. Interest accrued on deferred energy costs for the year ended December 31, 2005 was higher than the same period in 2004 due to higher deferred fuel and purchased power balances and carrying charge rates during 2005. See Note 3, Regulatory Actions, of the Notes to Financial Statements for further discussion of deferred energy accounting issues.

SPPC's other income increased for the year ended December 31, 2006 compared to the same period in 2005 primarily due to an increase in interest income associated with higher cash balances from the issuance of new debt in March 2006, as well as gains from the sale of property. SPPC's other income increased for the year ended December 31, 2005 compared to the same period in 2004 due primarily to an increase in interest income.

Disallowed merger costs expense includes the 2004 write-off of costs that resulted from the July 1999 merger between SPR and NPC, allocable to non-Nevada jurisdictional electricity sales, which were determined not to be recoverable in future rates.

SPPC's plant costs disallowed is the result of the decision by the PUCN to disallow recovery of a portion of the costs associated with the Piñon Pine power plant project. See Note 3, Regulatory Actions, and Note 13, Commitments and Contingencies of the Notes to Financial Statements for details.

SPPC's other expense for the year ended December 31, 2006 increased from the same period in 2005 due primarily to a loss on the disposition of property, higher donations, assistance program expenses and penalties. SPPC's other expense for the year ended December 31, 2005 increased from the same period in 2004. Higher expense was recognized during 2005 related to SPPC's California Restructure Implementation costs of approximately $1 million that were disallowed by the CPUC.

ANALYSIS OF CASH FLOWS

SPPC's cash flows decreased slightly during the year ended December 31, 2006 when compared to the same period in 2005 as a result of an increase in cash used by investing activities offset by an increase in cash from operating and financing activities.

Cash used by investing activities increased primarily as a result of the expansion of the Tracy plant during the year ended December 31, 2006 compared to the same period in 2005.

At various times during the year ended December 31, 2006, SPPC borrowed approximately $248 million under its revolving credit facility, all of which was repaid during 2006. SPPC also issued $300 million in 6.0% General and Refunding Mortgage Notes, Series M and $268 million in variable interest Pollution Control Revenue Bonds. A portion of the draw on the credit line was used to retire approximately $198 million of SPPC's Medium Term Notes Series A, B and C. The net proceeds of the $300 million offering were used to pay off amounts borrowed under the revolving credit facility, redeem $20 million of Medium Term Notes, Series C, redeem $50 million of preferred stock and pay associated costs, premiums and dividends. Proceeds from Pollution Control Bonds and cash from operations were used to retire $269 million of SPPC's existing tax-exempt bonds. In 2006, SPPC paid dividends to SPR of approximately $17.9 million and received a capital contribution of $75 million from SPR.

Cash from operating activities were higher in 2006 mainly due to the settlement of balances outstanding for tax sharing agreements, a reduction in prepayments for energy and increases in general and energy rates, offset by the settlement with Enron during the first quarter.

SPPC's cash flows increased during the year ended December 31, 2005 when compared to the same period in 2004 as a result of an increase in cash flows from operating activities partially offset by increases in cash used in investing and financing activities. Cash flows from operating activities were higher in 2005 due to rate increases that became effective in the second quarter of 2004, which was the result of SPPC's General and Deferred Rate Cases (refer to "Regulatory Proceedings"). Also causing an increase in cash flow from operations was the $11 million escrow payment for Enron in 2004, a reduction in prepayments and deposits for energy in 2005 due to the establishment of the revolving credit facility and changes in accounts receivables for tax sharing agreements, offset by energy costs being higher than amounts recovered in rates in 2005. Cash flows used in investing activities increased primarily as a result of construction activity related to growth. Cash used for financing activities increased due to payment of dividends to the parent in 2005, offset by the payoff of the short-term credit facility in 2004.

LIQUIDITY AND CAPITAL RESOURCES

Overall Liquidity

SPPC's primary source of operating cash flows are electric and gas revenues, including the recovery of previously deferred energy and gas costs. Significant uses of cash flows from operations include the purchase of electricity and natural gas, other operating expenses and the payment of interest on SPPC's outstanding indebtedness.

Available Liquidity as of December 31, 2006

(in millions)	SPPC
Cash and cash equivalents	$ 53.3
Balance available on revolving credit facility	340.6
Total available liquidity[1]	$393.9

(1) As of February 23, 2007, SPPC had approximately $331.1 million available under its revolving credit facility. Additionally, if necessary, SPPC has the ability to issue additional debt, as discussed under Limitations on Indebtedness.

In December 2006, SPR contributed capital to SPPC of approximately $75 million. SPPC used the proceeds to repay indebtedness under its revolving credit facility, and for general corporate purposes. There were no other capital contributions from SPR to SPPC in 2006.

In 2006, SPPC had paid $17.9 million in dividends to SPR and declared an additional $6.7 million dividend. In January 2007, SPPC paid the $6.7 million dividend to SPR.

SPPC anticipates that it will be able to meet operating costs, such as fuel and purchased power costs, with internally generated funds, including the recovery of deferred energy. However, to fund capital requirements, SPPC may be required to meet such financial obligations with a combination of internally generated funds, the use of its revolving credit facility and, if necessary, the issuance of long-term debt and/or capital contribution from SPR.

SPPC's overall liquidity continued to improve in 2006. The revolving credit facility was increased to $350 million in April 2006, providing $100 million of additional liquidity for increased commodity prices. SPPC's debt profile improved as a result of refinancing more than $536 million of long-term debt. These refinancings are expected to reduce future interest expense.

SPPC designs operating and capital budgets to control operating costs and capital expenditures. In addition to operating expenses, SPPC has continuing commitments for capital expenditures for construction, improvement and maintenance of facilities.

Detailed below are SPPC's Capital Structure, Capital Requirements, Contractual Obligations, recently completed Financing Transactions and Factors Affecting Liquidity including SPPC's ability to obtain debt on favorable terms and limitations on indebtedness.

Capital Structure

SPPC's actual consolidated capital structure was as follows at December 31:

	2006		2005	
Current maturities of long-term debt	**$ 2,400**	**0.1%**	$ 52,400	3.00%
Long-term debt	**1,070,858**	**54.7%**	941,804	53.1%
Preferred stock	**—**		50,000	2.8%
Common equity	**884,737**	**45.2%**	727,777	41.1%
Total	**$1,957,995**	**100.0%**	$1,771,981	100%

Capital Requirements

CONSTRUCTION EXPENDITURES SPPC's cash construction expenditures are expected to increase due to programs designed to meet electric load growth and reliability needs. Cash construction expenditures for the years ended 2006, 2005 and 2004 were approximately $285 million, $113 million and $104 million, respectively. SPPC's cash construction expenditures for 2007 are projected to be $432.8 million. SPPC's cash construction expenditures for 2007 through 2011 are projected to be $1.9 billion. To fund these capital projects, SPPC may meet such financial obligations with a combination of internally generated funds, the use of its revolving credit facility and, if necessary, the issuance of long-term debt and/or capital contributions from SPR. Depending on the progress of the Ely Energy Center, the timing and extent of the estimated capital expenditures necessary may change.

CONTRACTUAL OBLIGATIONS The table below provides SPPC's consolidated contractual obligations, not including estimated construction expenditures described above, as of December 31, 2006 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						
	2007	2008	2009	2010	2011	Thereafter	Total
Long-term debt maturities	$ 2,400	$322,400	$ 80,600	$ —	$ —	$ 668,250	$1,073,650
Long-term debt interest payments	61,979	49,235	38,386	38,377	38,377	402,091	628,445
Purchased power	163,165	125,161	98,028	93,836	95,231	1,308,566	1,883,987
Coal and natural gas	201,068	85,018	73,392	48,418	48,418	361,358	817,672
Capital purchase agreements	13,121	—	—	—	—	—	13,121
Operating leases	10,635	10,297	8,931	7,587	778	36,587	74,815
Total contractual cash obligations	$452,368	$592,111	$299,337	$188,218	$182,804	$2,776,852	$4,491,690

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 is expected to decrease in 2007 by approximately $1.3 million compared to the 2006 cost of $30.6 million. As of September 30, 2006, the measurement date, the plan was fully funded on a FAS 87 ABO basis (fair value of assets exceeded ABO). During 2006, SPR contributed a total of $16 million to meet its funding obligations under the plan. At the present time it is not expected that any additional funding will be required in 2007 to meet the minimum funding level requirements defined by the Pension Benefit Guaranty Corporation and ERISA. However, SPR and the Utilities currently expect to contribute an amount similar to the 2006 funding. The amounts to be contributed may change subject to market conditions.

Financing Transactions (SPPC)

POLLUTION CONTROL AND GAS AND WATER FACILITIES REFUNDING REVENUE BONDS, SERIES 2006, 2006A, 2006B AND 2006C In November 2006, on behalf of SPPC, Humboldt County, Nevada (Humboldt County), issued $49.75 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006, due October 2029. On the same date, on behalf of SPPC, Washoe County, Nevada (Washoe County), issued $58.7 million aggregate principal amount of it Gas Facilities Refunding Revenue Bonds, Series 2006A, due August 2031; $75 million aggregate principal amount of its Water Facilities Refunding Revenue Bonds, Series 2006B, due March 2036; and $84.8 million aggregate principal amount of its Gas and Water Facilities Refunding Revenue Bonds, Series 2006C, due March 2036.

In connection with the issuance of these Bonds, SPPC entered into financing agreements with Humboldt County and Washoe County, pursuant to which Humboldt County and Washoe County loaned the proceeds from the sales of the bonds to SPPC. SPPC's payment obligations under the financing agreements are secured by SPPC's General and Refunding Mortgage Notes, Series N.

The interest rates of the Bonds were initially determined by an auction. The method of determining the interest rate on the Bonds may be converted from time to time so that such Bonds would thereafter bear interest at a daily, weekly, flexible, auction or term rate as designated.

The proceeds of the offerings were used to refund the following, all of which were previously issued for the benefit of SPPC:

- $17.5 million principal amount of 6.65% Washoe County's Gas Facilities Refunding Revenue Bonds, Series 1987
- $20 million principal amount of 6.55% Washoe County's Gas Facilities Refunding Revenue Bonds, Series 1990
- $21.2 million principal amount of 6.70% Washoe County's Gas Facilities Refunding Revenue Bonds, Series 1992
- $75 million principal amount of 6.65% Washoe County's Water Facilities Refunding Revenue Bonds, Series 1987
- $45 million principal amount of 6.30% Washoe County's Gas and Water Facilities Refunding Revenue Bonds, Series 1987
- $30 million principal amount of 5.90% Washoe County's Gas and Water Facilities Refunding Revenue Bonds, Series 1993B
- $9.8 million principal amount of 5.90% Washoe County's Water Facilities Refunding Revenue Bonds, Series 1993A
- $39.5 million principal amount of 6.55% Humboldt County's Pollution Control Refunding Revenue Bonds, Series 1987
- $10.25 million principal amount of 6.30% Humboldt County's Pollution Control Refunding Revenue Bonds, Series 1992A

HUMBOLDT COUNTY POLLUTION CONTROL REFUNDING REVENUE BONDS In October 2006, the 6.35% Humboldt County's Pollution Control Refunding Revenue Bonds, Series 1992B, due August 2022, in the amount of $1 million were redeemed at 100% of the stated principal amount, plus accrued interest.

REVOLVING CREDIT FACILITY In April 2006, SPPC increased the size of its Amended and Restated Revolving Credit Facility expiring 2010 to $350 million. The facility will provide additional liquidity for increased commodity prices and temporary bridge financing of capital expenditures. As of December 31, 2006, SPPC had $9.4 million of letters of credit outstanding and had no amounts borrowed under the revolving credit facility. As of February 23, 2007, SPPC had $18.9 million of letters of credit and had no amounts borrowed under the revolving credit facility.

The SPPC Credit Agreement contains two financial maintenance covenants. The first requires that SPPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that SPPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1. As of December 31, 2006, SPPC was in compliance with these covenants.

The SPPC Credit Agreement provides for an event of default if there is a failure under SPPC's other financing agreements to meet certain payment terms or to observe other covenants that would result in an acceleration of payments due.

The SPPC Credit Agreement places certain restrictions on debt incurrence, liens and dividends. These limitations are discussed in Note 8, Debt Covenant and Other Restrictions.

GENERAL AND REFUNDING MORTGAGE NOTES, SERIES M In March 2006, SPPC issued and sold $300 million of its 6.00% General and Refunding Mortgage Notes, Series M, due May 15, 2016. The Series M Notes were issued with registration rights. Proceeds of the offering were used to repay $173 million borrowed under the revolving credit facility which was utilized to:

- fund the early redemption of $110 million aggregate principal amount of SPPC's Collateralized Medium Term 6.95% to 8.61% Series A Notes due 2022;
- fund the early redemption of $58 million aggregate principal amount of SPPC's Collateralized Medium Term 7.10% to 7.14% Series B Notes due 2023;
- pay for maturing debt of $30 million aggregate principal amount of SPPC's Collateralized Medium Term 6.81% to 6.83% Series C Notes due 2006; and
- pay for $51 million in connection with the redemption of $50 million of SPPC's Series A Preferred Stock (two million shares of stock were redeemed at a redemption price per share of $25.683, plus accrued dividends to the redemption date of $.4875 per share).
- pay for maturing debt of $20 million aggregate principal amount of SPPC's Collateralized Medium Term 6.62% to 6.65% Series C Notes due 2006.

DISCHARGE OF SPPC'S FIRST MORTGAGE INDENTURE In November 2006, following the refunding of the $268.25 million aggregate principal amount of Pollution Control and Gas & Water Refunding Revenue Bonds (see Financing Transactions above), the first mortgage bonds which secured these revenue bonds were retired.

In November 2006, the remaining $20 million aggregate principal amount of Series C Medium Terms Notes matured. On that date, the first mortgage bonds which secured the Medium Term Notes were retired.

With the conclusion of these two transactions, all of the bonds outstanding under the First Mortgage Indenture were retired as of November 2006, and all filings necessary to make effective the release of the lien of the First Mortgage Indenture were completed as of January 2007. Upon the satisfaction and discharge of the First Mortgage Indenture, SPPC's General and Refunding Mortgage Indenture, dated as of May 2001, with the Bank of New York as Trustee, became the first priority lien on substantially all of SPPC's utility property in Nevada and California.

Factors Affecting Liquidity

LIMITATIONS ON INDEBTEDNESS Certain factors impact SPPC's ability to issue debt:

1. Financing Authority from the PUCN. In February 2006, SPPC received PUCN authorization to enter into financings of $1.36 billion, which amount includes $350 million for the revolving credit facility (described above). SPPC has issued $21 million of the new debt authorized in the PUCN Order. SPPC's remaining authority under this PUCN Order allows SPPC to use its $350 million revolving credit facility, to issue $349 million in new debt, and to refinance existing debt as specified in the order.
2. Limits on Bondable Property. To the extent that SPPC has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, SPPC's ability to issue secured debt is still limited by the amount of bondable property or retired bonds that can be used to issue debt under the General and Refunding Mortgage Indenture. As of December 31, 2006, SPPC has the capacity to issue $381 million of General and Refunding Mortgage Securities.
3. Financial Covenants in its and SPR's financing agreements. The terms of certain SPR debt further prohibit SPPC and NPC from incurring additional indebtedness unless certain conditions have been met. See SPR's Limitations on Indebtedness for details of these restrictions. In addition to the SPR debt, the terms of SPPC's Series H Notes and SPPC's Amended and Restated Revolving Credit Agreement restrict SPPC from issuing additional indebtedness unless certain covenants are satisfied. See Note 8, Debt Covenant and Other Restrictions.

   As of December 31, 2006, the financial covenants under SPPC's revolving credit facility, which are more restrictive than the Series H Notes restriction, would allow SPPC to issue up to $797 million of additional debt. The covenant limitations of certain SPR debt place a cap on additional indebtedness, on a consolidated basis, including SPPC and NPC, at $2.1 billion as of December 31, 2006.

   Since SPR's debt covenant limitations are calculated on a consolidated basis, SPR's debt covenant limitations may allow for higher or lower borrowings than $2.1 billion, depending on the Utilities' combined usage of their revolving credit facilities at the time of the covenant calculation.

LIMITATIONS ON ABILITY TO ISSUE GENERAL AND REFUNDING MORTGAGE BONDS SPPC's General and Refunding Mortgage Indenture creates a lien on substantially all of SPPC's properties in Nevada and California. As of December 31, 2006, $1.4 billion of SPPC's General and Refunding Mortgage Securities were outstanding. As mentioned in (2) above under "Limitations on Indebtedness," additional securities may be issued under the General and Refunding Mortgage Indenture as of December 31, 2006. That amount has been determined on the basis of:

1. 70% of net utility property additions;
2. the principal amount of retired General and Refunding Mortgage Securities; and/or
3. the principal amount of first mortgage bonds retired after October 2001.

SPPC also has the ability to release property from the lien of the General and Refunding Mortgage Indenture 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 securities issuable under that indenture.

CREDIT RATINGS SPPC is rated by four Nationally Recognized Statistical Rating Organizations: S&P, Moody's, Fitch, and DBRS. As of February 23, 2007, the ratings are as follows:

		Rating Agency			
		DBRS	Fitch	Moody's	S&P
SPPC	Sr. secured debt	BBB (low)*	BBB-*	Ba1	BB+

** Ratings are investment grade*

In February 2007, DBRS, who had not previously issued ratings on SPPC, assigned new ratings to SPPC's senior secured debt. The rating is BBB (low), which is the minimum level for investment grade. DBRS's trend for SPPC is Stable.

In 2006, there were other changes to the ratings of SPPC's debt. Fitch upgraded the ratings for SPPC's senior secured debt to BBB-, the minimum level for investment grade, and revised the rating outlook for SPPC from Positive to Stable. S&P upgraded the ratings of SPPC's senior secured debt from BB to BB+, one level below investment grade. Moody's re-affirmed its ratings for SPPC's senior secured debt at Ba1, one level below investment grade.

A security rating is not a recommendation to buy, sell or hold securities. Security ratings are subject to revision and withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating.

ENERGY SUPPLIER ISSUES With respect to SPPC's contracts for purchased power, SPPC purchases and sell electricity with counterparties under the Western Systems Power Pool (WSPP) agreement, an industry standard contract that SPPC is 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 request adequate financial assurance, which, if not provided within three 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 three 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 December 31, 2006 for all suppliers continuing to provide power under a WSPP agreement would approximate a $44.5 million payment by SPPC. These contracts qualify for the normal purchases scope exception of SFAS No. 133, and as such, are not required to be marked to market on the balance sheet. Refer to Note 9, Derivatives and Hedging Activities, of the Notes to Financial Statements for further discussion.

GAS SUPPLIER ISSUES With respect to the purchase and sale of natural gas, SPPC uses several types of standard industry contracts. 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. Because of creditworthiness concerns, most contracts and confirmations for natural gas purchases have been modified or separate agreements have been made to either shorten the normal payment due date or require payment in advance of delivery. At the present time, four counterparties require payment in advance of delivery.

Gas transmission service is secured under FERC Tariffs or custom agreements. These service contracts and Tariffs require the user establish and maintain creditworthiness to obtain service or otherwise post cash or a letter of credit to be able to receive service. Service contracts are subject to FERC approved tariffs, which, under certain circumstances, require the Utility to provide collateral to continue receiving service.

CROSS-DEFAULT PROVISIONS SPPC's financing agreements do not contain any cross-default provisions that would result in an event of default by SPPC upon an event of default by SPR or NPC under any of their respective financing agreements. Certain financing agreements of SPPC provide for an event of default if there is a failure under other financing agreements of SPPC 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 such other indebtedness when due) provide for a cure period of 30-60 days from the occurrence of a specified event during which time SPPC may rectify or correct the situation before it becomes an event of default.

REGULATORY PROCEEDINGS (UTILITIES)

SPR is a "holding company" under the Public Utility Holding Company Act of 2005 (PUHCA 2005). As a result, SPR and all of its subsidiaries (whether or not engaged in any energy-related business) are required to maintain their books and records in accordance with Federal Energy Regulatory Commission ("FERC") regulations and to make them available to the FERC, the Public Utilities Commission of Nevada ("PUCN") and California Public Utility Commission ("CPUC"). In addition, the PUCN, CPUC, and the FERC have the authority to review the allocation of costs of non-power goods and administrative services among SPR and its subsidiaries. The FERC has the general authority to require that rates subject to its jurisdiction be just and reasonable and in this context would continue to be able to, among other things, review transactions between SPR, NPC and/or SPPC and/or any other affiliated company. SPR does not expect that the new PUHCA law or the regulations promulgated by the FERC will have a material impact on the company and how its public utility subsidiaries are regulated.

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 ("IRPs") to the PUCN for approval.

Under federal law, the Utilities 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 the governmental commissions. The following regulatory proceedings have affected, or are expected to affect the utilities' financial positions, results of operations and cash flows.

The Utilities are required to file annual periodic Deferred Energy Accounting Adjustment (DEAA) cases, annual Base Tariff Energy Rate (BTER) Updates and biennial General Rate Cases (GRCs) in Nevada. A DEAA case is filed to recover/refund any over/under collection of prior energy costs, and the BTER update is to set rates to recover current energy costs. A GRC filing is to set rates to recover operation and maintenance expenses, depreciation, taxes and provide a return on invested capital. As of December 31, 2006, NPC's and SPPC's balance sheet included approximately $488.9 million and $61.6 million, respectively, of deferred energy costs of which approximately $334.8 million and $33.7 million have been previously approved for collection over various periods. The remaining amounts will be requested in future regulatory filings. Refer to Note 1, Summary of Significant Accounting Policies, of the Notes to Financial Statements.

The following summarizes pending and approved rate case applications filed in 2005, 2006 and 2007. Each of these rate cases, as well as other regulatory matters such as the Utilities' Integrated Resource Plans and subsequent amendments, other Nevada matters, California matters and FERC matters, are discussed in more detail within this section.

Pending Rate Cases

- NPC 2007 Deferred Energy Rate Case and BTER Update—Application to create a new DEAA rate and to update the going forward BTER. In this application, NPC requests to decrease rates by $33.2 million, a decrease of 1.6%, while recovering $75 million of deferred fuel and purchased power costs. NPC has requested the amortization to begin June 1, 2007 and to continue for a fourteen-month period.

- NPC 2007 Western Energy Crisis Rate Case—Application to recover approximately $83.6 million in deferred legal and settlement costs incurred to resolve claims arising from the Western Energy Crisis. This application requests an overall rate increase of 0.94% and to begin amortizing the costs over a four-year period beginning June 1, 2007.

  In February 2007, NPC entered into a stipulation, with the parties to the case, to recover the $83.6 million plus carrying charges over a 3-year period beginning June 1, 2007. This stipulation is expressly conditioned upon the PUCN's acceptance of the concurrently filed stipulation related to NPC's 2001 Deferred Energy Case, discussed below. If the PUCN does not accept both stipulations, this stipulation shall be deemed withdrawn, and all parties will retain all rights to litigate. The PUCN has yet to issue an order on the stipulation.

- NPC 2006 General Rate Case—Application to reset General Rates. This legislatively mandated filing requests authorization to increase general rates by $172.4 million, which is approximately an 8% increase. In this application, the Company requested that the Return on Equity ("ROE") and Rate of Return ("ROR") be set at 11.40% and 9.41%, respectively. NPC expects the new rates to be in effect on or before June 1, 2007.

  In February 2007, NPC submitted its certification filing. This filing did not change the requested ROE, but the ROR decreased to 9.39% and the general revenue increase was lowered to $156.4 million.

- SPPC 2006 Nevada Electric Deferred Energy Rate Case and BTER Update—Application to create a new electric DEAA rate and to update the electric BTER. In this application, SPPC requests to decrease rates by $7.9 million, a decrease of .86%, while recovering $18.7 million of deferred fuel and purchased power costs. SPPC is seeking recovery using a symmetrical two-year amortization period beginning July 1, 2007.

- SPPC 2006 Nevada Western Energy Crisis Rate Case—Application to recover $22.6 million in deferred legal and settlement costs incurred to resolve claims arising from the Western Energy Crisis. This application requests an overall rate increase of 0.53% and to begin amortizing the costs over a four-year period beginning July 1, 2007.

  In February 2007, SPPC entered into a stipulation where SPPC replaces its request to implement rates on July 1, 2007 with a request to establish a regulatory asset to recover the costs. SPPC further requests authority to recover carrying charges on the regulatory asset. SPPC may request authority to begin recovering the regulatory asset established by the PUCN in a future application to change rates. The parties to the stipulation have requested that the PUCN issue an order by September 30, 2007.

Other Pending Matters

- NPC 2001 Deferred Energy Case—In July 2006, the Supreme Court of Nevada issued a ruling that will allow NPC to recover approximately $180 million of deferred energy, which was disallowed in NPC's 2001 Deferred Energy Case. The decision directs the District Court to remand the matter back to the PUCN to determine the appropriate rate schedule.

  In February 2007, NPC entered into a stipulation where NPC shall be authorized to recover in rates $189.9 million over ten years beginning on June 1, 2007, with no additional carrying charges. This stipulation is expressly conditioned upon the PUCN's acceptance of the concurrently filed stipulation related to the Western Energy Crisis, discussed above. If the PUCN does not accept both stipulations, this stipulation shall be deemed withdrawn, and all parties will retain all rights to litigate. The PUCN has yet to issue an order on the stipulation.

Approved Rate Cases

- NPC 2006 Deferred Energy Rate Case and BTER Update—Application to create a new DEAA rate and to update the going forward BTER. In April 2006, the PUCN approved a new BTER, which would increase purchased fuel and power revenues by an estimated $112 million. In June 2006, the PUCN approved a negotiated settlement of the deferred energy phase of the case, which, based on an updated forecast, reduced the previously approved BTER revenue by approximately $1.6 million and allowed full recovery of $171.5 million in deferred costs, with an effective date of May 1, 2006.

- SPPC 2006 Nevada Natural Gas and Propane Deferred Energy Rate Case and BTER Update—Application to create a new DEAA rate and to update the BTER. In October 2006, the PUCN approved negotiated settlements to recover $1.1 million in deferred natural gas and propane costs and to set the going forward energy rates such that $1.3 million of new revenues would be collected. The settlements, combined with the expiration of a previous natural gas DEAA rate, will yield a 2.5% rate reduction for natural gas customers and a 3.3% increase for propane customers.

- SPPC 2005 Nevada Electric Deferred Energy Rate Case and BTER Update—Application to create a new electric DEAA rate and to update the electric BTER. In April 2006, the PUCN approved a new Electric BTER, which will increase purchased fuel and power revenues by an estimated $31 million. In June 2006, the PUCN approved a negotiated settlement, which granted SPPC full recovery of $46.7 million in deferred costs during a two-year period beginning July 2006.

- SPPC 2005 Nevada Electric General Rate Case—Application to reset electric general rates. In April 2006, the PUCN authorized a 10.6% ROE and 8.96% ROR and ordered SPPC to reduce general revenues for electric services by approximately $14 million.

- SPPC 2005 Nevada Gas General Rate Case—Application to reset gas general rates. In April 2006, the PUCN authorized a 10.6% ROE and 7.98% ROR and ordered SPPC to increase general revenues for gas services by approximately $4.5 million.

- SPPC 2006 California Energy Cost Adjustment Clause Rate Case—Application to reset energy rates. The total request sought to collect an additional $11.2 million annually for deferred and going forward costs related to fuel and power purchases. The two requested rate increases total 16.5%. In October 2006, the CPUC approved the application as filed, with an effective date of November 1, 2006.
- SPPC 2005 California General Rate Case—Application to reset General Rates. In August 2006, the CPUC approved a settlement agreement which, beginning on September 2006, allowed SPPC to collect an estimated $4.1 million of additional general revenues.

NEVADA MATTERS

Nevada Power Company

2007 DEFERRED ENERGY RATE CASE AND BTER UPDATE In January 2007, NPC filed an electric DEAA Rate Case and BTER Update application with the PUCN. The application seeks recovery of $75 million of deferred fuel and purchased power costs and requested to reset NPC's going forward BTER to reflect anticipated changes in future energy costs. This application requests a 1.6% decrease in overall rates.

2007 WESTERN ENERGY CRISIS RATE CASE In January 2007, NPC filed an application to recover $83.6 million over four years in deferred legal and settlement costs incurred to resolve claims associated with power supply contracts terminated during the western energy crisis. This application requests an overall rate increase of less than 1%.

In February 2007, NPC entered into a stipulation, with the parties to the case, to recover the $83.6 million plus carrying charges over a 3-year period beginning June 1, 2007. This stipulation is expressly conditioned upon the PUCN's acceptance of the concurrently filed stipulation related to NPC's 2001 Deferred Energy Case, discussed below. If the PUCN does not accept both stipulations, this stipulation shall be deemed withdrawn, and all parties will retain all rights to litigate. The PUCN has yet to issue an order on the stipulation.

2006 GENERAL RATE CASE In November 2006, NPC filed its statutorily required Electric General Rate Case. This filing requests authorization to:

- Increase annual general revenues by $172.4 million which is approximately an 8% increase.
- Set the Return on Equity and Rate of Return at 11.40% and 9.41%, respectively.
- Recover 100% of the amortization of the 1999 NPC/SPPC merger costs rather than the 80% recovery that is currently in general rates.
- Implement the PUCN's previous orders regarding incentive ratemaking for the Chuck Lenzie Generating Station.
- Implement new depreciation rates.

Hearings are scheduled to take place in late March and early April of 2007 with rates expected to be effective on or before June 1, 2007.

In February 2007, NPC submitted its certification filing which lowered the requested ROR to 9.39% and the general revenues increase was lowered to $156.4 million, representing an overall rate increase of 7.4%.

2006 DEFERRED ENERGY RATE CASE AND BTER UPDATE In January 2006, NPC filed an application with the PUCN seeking recovery of $171.5 million of deferred fuel and purchased power costs and to increase its going forward BTER to reflect anticipated changes in future energy costs. The application requests an overall rate increase of approximately 17%.

In April 2006, the PUCN approved an agreement among the interveners and NPC, which, effective May 1, 2006, set NPC's BTER rates such that an estimated $112 million (revised by June 2006 DEAA agreement – see below) of new revenues would be collected for fuel and power purchases in addition to the start of an $8.4 million collection related to a previous DEAA Rate Case. Combined, the approximately $120 million increase represented an overall average rate increase of approximately 6.5%.

In the Deferred Energy portion of the case, NPC had requested authorization to recover $171.5 million of previously incurred purchased fuel and power costs over a one-year period. In June 2006, the PUCN approved a negotiated settlement, which specified (1) a reduction of $1.6 million to the BTER approved in April 2006 based on an updated projection of costs and (2) granted NPC full recovery of the $171.5 million of deferred costs during a two-year period beginning August 2006. However, the $171.5 million was reduced by a $16.5 million payment previously received by NPC in connection with the Lenzie acquisition. Under this agreement, the DEAA rate changes required to asymmetrically recover the deferred balance are scheduled to be implemented during a two-year period such that they will be offset by the expiration of previously approved DEAA rates. As a result, no rate increase was required.

2001 DEFERRED ENERGY CASE In November 2001, NPC made a deferred energy filing with the PUCN seeking repayment 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 rate to repay 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.

In March 2002, the PUCN issued its Order on the 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. NPC and the Bureau of Consumer Protection (BCP) both sought individual review of the PUCN Order in the First District Court of Nevada. The District Court affirmed the PUCN's decision. Both NPC and the BCP filed Notices of Appeal with the Nevada Supreme Court.

In July 2006, the Supreme Court of Nevada issued a ruling that will allow NPC to recover approximately $180 million of deferred energy, which was disallowed in NPC's 2001 Deferred Energy Case. The decision directs the District Court to remand the matter back to the PUCN to determine the appropriate rate schedule.

In February 2007, NPC entered into a stipulation where NPC shall be authorized to recover in rates $189.9 million over ten years beginning on June 1, 2007, with no additional carrying charges. This stipulation is expressly conditioned upon the PUCN's acceptance of the concurrently filed stipulation related to the Western Energy Crisis, discussed above. If the PUCN does not accept both stipulations, this stipulation shall be deemed withdrawn, and all parties will retain all rights to litigate. The PUCN has yet to issue an order on the stipulation.

2006 INTEGRATED RESOURCE PLAN In June 2006, NPC filed its 2006 triennial Integrated Resource Plan with the PUCN. The filing requested approval to develop new conventional and renewable generation resources, improve NPC's transmission system and increase demand side initiatives. The demand side programs are intended to help customers use electricity more efficiently and also contribute to NPC's Renewable Portfolio requirements. The following are the key elements of the filing:

- Requested approval to construct the following supply side resources:
    1. Two 750 MW critical coal-fired generation units at the proposed Ely Energy Center in White Pine County, Nevada, estimated to be in service by 2011 and 2013, respectively. Also, part of this project is a 250-mile 500 kV transmission line to integrate the new generation into both NPC's and SPPC's systems and to allow delivery of geothermal resources from Northern Nevada to NPC and solar-powered generation from Southern Nevada to SPPC.
    2. Construction of 600 MW of gas-fired combustion turbine peaking generation, 400 MW in service by 2008 and 200 MW in service by 2009.
- Requested the PUCN to designate the Ely Energy Center and the 500 kV transmission intertie as critical facilities under Nevada regulations and requested incentive ratemaking treatment including "CWIP in rate base" during construction and, upon completion, a 2% enhanced ROE and accumulation of depreciation expense in a regulatory asset account from the time the plants are placed in service until they are included in rates.
- Outlined initiatives, including NPC ownership positions in renewable energy projects, which are expected to enable NPC to meet Nevada's Portfolio Standards.
- Requested approval of four new demand side programs and to increase spending on eight existing demand side programs.
- Outlined NPC's ten-year $4.7 billion budget for all of the proposed initiatives.

In September 2006, NPC provided testimony that modified its request for critical facility designations and associated incentive ratemaking treatments, which included the withdrawal of the following:

- Incentive ratemaking treatment for the initial $300 million project development costs.
- NPC's request for a specific enhanced ROE in this docket; however, NPC stated it would resubmit a request for an enhanced ROE in a future filing.

In October 2006, the PUCN approved a negotiated settlement of NPC's 2007-2009 Energy Supply Plan, which was a component of its integrated resource plan filing.

In November 2006, the PUCN issued an order with the findings of that order listed below:

- Supply Side Resources
    1. PUCN granted the Utilities' request to proceed with the development of Phase I of the Ely Energy Center and accompanying transmission line. The PUCN also approved the Utilities' request of $300 million for development activities associated with the Ely Energy Center with a limitation of $155 million placed on expenditures until the Utilities have obtained the final air permit. The PUCN approved the request to initially allocate the costs between NPC and SPPC using an 80/20 cost allocation, respectively. Furthermore, the PUCN granted NPC's request for critical facility designation, thereby allowing it to qualify for incentives to be determined at a later date.

       The PUCN also directed the Utilities, upon receipt of the air permit, to prepare and submit a subsequent filing in the form of a resource plan amendment ("Ely Energy Center Amendment") in which they will ask for PUCN approval to proceed with the construction of the Ely Energy Center and transmission line based on detailed engineering, construction and cost estimates, and a refined project schedule.
    2. The PUCN approved NPC's request to construct 600 MW of nominally rated quick-start combustion turbine units at the Clark Station at a cost of approximately $395 million, with approximately 400 MWs of peaking capacity to be installed prior to the summer of 2008 and approximately 200 MWs of additional peaking capacity to installed prior to the summer of 2009.

Material Amendments to NPC's 2006 Integrated Resource Plan

In January 2007, NPC filed an amendment to its 2006 Integrated Resource Plan requesting approval to expend $60 million to install new ultra-low emission burners on the four combustion turbines serving the combined-cycle units at the Clark Generating Station.

Material Amendments to NPC's 2003 Integrated Resource Plan

REQUEST FOR AUTHORIZATION TO ACQUIRE LAND & LAND RIGHTS FOR TRANSMISSION FACILITIES In January 2006, NPC filed an amendment to its 2003 Integrated Resource Plan requesting approval to acquire approximately $57 million of strategic investments in land and land rights necessary for future 500 kV and 230 kV transmission facilities. NPC also requested approval to accrue a carrying charge on the investments, which would be equal to the current Allowance for Funds Used During Construction.

In April 2006, the PUCN approved a negotiated agreement that authorizes NPC to invest $37 million in land and land rights and to include authorized investments in the rate base calculation for its next general rate case.

Enhanced ROE Due to Early Completion of Lenzie Generating Station

The PUCN designated Lenzie a critical facility and allowed a 2% enhancement to the authorized ROE when the PUCN approved NPC's request to acquire the facility. The PUCN further allowed up to an additional .5% enhanced ROE if the Lenzie Block #1 generator units (two combustion turbine/generators and one steam turbine/generator) were commercially operable before March 2006 and another .5% ROE enhancement if Block #2 was completed before June 2006.

In January 2006, the first 600 MW combined-cycle unit (Block #1) was declared commercially operable. In April 2006, NPC announced that Lenzie Block #2 was commercially operable. NPC's construction costs are projected to be less than the amount authorized by the PUCN. NPC believes it is eligible to receive a 3% enhancement to the otherwise authorized ROE that will be decided as a result of its GRC filing that it made in November 2006. See Note 1, Summary of Significant Accounting Policies, of Notes to Financial Statements for further discussion on the accounting for the enhancement.

Sierra Pacific Power Company

2006 ELECTRIC DEFERRED ENERGY RATE CASE AND BTER UPDATE

In December 2006, SPPC filed an electric DEAA Rate Case and BTER Update application with the PUCN. The application seeks recovery of $18.7 million of deferred fuel and purchased power costs and requested to reset SPPC's going forward BTER to reflect anticipated changes in future energy costs. This application requests a 0.86% decrease in overall rates.

2006 WESTERN ENERGY CRISIS RATE CASE In December 2006, SPPC filed an application to recover $22.6 million over four years in deferred legal and settlement costs incurred to resolve claims associated with power supply contracts terminated during the Western Energy Crisis. This application requests an overall rate increase of 0.53%.

In February 2007, SPPC entered into a stipulation where SPPC replaces its request to implement rates on July 1, 2007 with a request to establish a regulatory asset to recover the costs. SPPC further requests authority to recover carrying charges on the regulatory asset. SPPC may request authority to begin recovering the regulatory asset established by the PUCN in a future application to change rates. The parties to the stipulation have requested that the PUCN issue an order by September 30, 2007.

2006 NATURAL GAS AND PROPANE DEFERRED ENERGY RATE CASE AND BTER UPDATE In May 2006, SPPC's gas distribution operation filed applications with the PUCN seeking recovery of deferred natural gas and propane costs accumulated between April 1, 2005 and March 31, 2006. The applications sought to establish a new natural gas DEAA rate to recover $2.5 million of deferred natural gas costs and a new propane DEAA rate to recover $120 thousand of deferred propane costs. SPPC also requested authorization to increase going forward natural gas and propane BTER's to reflect forecasted gas costs.

In October 2006, the PUCN approved negotiated natural gas and propane settlements which consolidated the deferred natural gas and propane balances for collection from all gas customers and reduced the combined balance to $1.1 million. The agreements transferred approximately $1.4 million to other deferral periods and $.1 million to expense accounts. The agreements called for the cost recovery to occur over a 12-month period beginning December 2006.

The negotiated going forward natural gas rate is expected to recover an additional $1.3 million in revenue, which is a decrease from the originally requested $24.5 million. The decrease reflects more current natural gas price expectations.

These settlements, combined with the expiration of a previous natural gas DEAA rate, will cause natural gas customer rates to decrease by 2.5% and cause propane customer rates to increase by 3.3%.

2005 ELECTRIC DEFERRED ENERGY RATE CASE AND BTER UPDATE

In December 2005, SPPC filed an electric Deferred Energy Rate Case application with the PUCN. The application sought to establish a rate to collect accumulated fuel and purchased power costs of $46.7 million from the December 2004 to September 2005 deferral period and $17.5 million from the previously approved unamortized deferrals, for a total $64.2 million. In June 2006, the PUCN approved a negotiated settlement, which granted SPPC full recovery of the deferred costs during a two-year period beginning July 2006. Under this agreement, the DEAA rate changes required to asymmetrically recover the $46.7 million deferred balance are scheduled to be implemented such that they will be offset by the expiration of previously approved DEAA rates. As a result, no rate increase was required.

The application also requested an increase to the BTER. In April 2006, the PUCN issued an order authorizing SPPC to increase its BTER on May 1, 2006, such that SPPC expects to collect $31 million in new revenues for purchased power. The change represented a 3.5% increase to customer rates.

2005 ELECTRIC AND GAS GENERAL RATE CASES In October 2005, SPPC filed a gas General Rate Case along with its statutorily required electric General Rate Case. SPPC's last gas General Rate Case was filed in 1992 and the last electric General Rate Case was filed in 2003. The following items were requested in the filings:

- Electric general revenue increase: $27 million or 3.4% effective May 1, 2006
- Gas general revenue increase: $8.3 million or 5.4%, effective May 1, 2006
- Electric Return on Equity and Rate of Return: 11.4% and 9.27%, respectively
- Gas Return on Equity and Rate of Return: 11.4% and 8.29%, respectively
- Approval to continue to recover an allocated amount of the 1999 NPC/SPPC merger costs from electric customers
- Approval to recover an allocated amount of the 1999 NPC/SPPC merger costs from gas customers
- New depreciation rates for gas and electric facilities

In April 2006, the PUCN issued its order to change electric and gas general rates. Although the order differed from SPPC's requested filing, the changes did not require material adjustments to net income for the six months ended June 30, 2006. The PUCN vote resulted in the following significant items:

- Electric general revenue decrease: approximately $14 million annually or 1.5% effective May 1, 2006
- Gas general revenue increase: $4.5 million annually or 2.3% effective May 1, 2006

- Electric Return on Equity and Rate of Return: 10.6% and 8.96%, respectively
- Gas Return on Equity and Rate of Return: 10.6% and 7.98%, respectively
- Approval to continue recovery of SPPC's allocated amount of the 1999 NPC/SPPC merger costs and goodwill from electric customers
- Approval to recover an allocated amount of the 1999 NPC/SPPC merger costs and goodwill from gas customers
- New depreciation rates for gas and electric facilities
- Deferred recovery of legal expenses related to the Enron purchased power contract litigation

MATERIAL AMENDMENTS TO SPPC'S 2004 INTEGRATED RESOURCE PLAN In July 2006, SPPC filed the thirteenth amendment to its 2004 Integrated Resource Plan. The following are the key elements of the filing:

- Requested approval to construct two 750 MW critical coal-fired generation units at the proposed Ely Energy Center in White Pine County, Nevada, estimated to be in service by 2011 and 2013 respectively. Also, part of this project is a 250-mile 500 kV transmission line to integrate the new generation into both NPC's and SPPC's systems and to allow delivery of geothermal resources from Northern Nevada to NPC and solar-powered generation from Southern Nevada to SPPC. The Utilities are currently estimating that 80% of the costs will be allocated to NPC and 20% will be allocated to SPPC.
- Requested the PUCN to designate the Ely Energy Center and the 500 kV transmission intertie as critical facilities under Nevada regulations and requested incentive ratemaking treatment including "CWIP in rate base" during construction and, upon completion, a 2% enhanced ROE and accumulation of depreciation expense in a regulatory asset account from the time the plants are placed in service until they are included in rates.
- Requested approval to make certain enhancements to SPPC's existing fleet of generators.
- Provided a $3.8 billion total estimate for the Ely Energy Center and outlines SPPC's cost for other proposed initiatives totaling approximately $15 million.

In September 2006, SPPC provided testimony that modified its request for critical facility designations and associated incentive ratemaking treatments, which included the withdrawal of the following:

- Incentive ratemaking treatment for the initial $300 million project development costs.
- SPPC's request for a specific enhanced ROE in this docket; however, SPPC stated it would resubmit a request for an enhanced ROE in a future filing.

In October 2006, the PUCN approved a negotiated settlement of SPPC's 2007 Energy Supply Plan Update, which was a component of its integrated resource plan amendment.

In November 2006, the PUCN issued an order with the findings of that order listed below:

- Supply Side Resources

The PUCN granted the Utilities' request to proceed with the development of Phase I of the Ely Energy Center and accompanying transmission line. The PUCN also approved the Utilities' request of $300 million for development activities associated with the Ely Energy Center with a limitation of $155 million placed on expenditures until the Utilities have obtained the final air permit. The PUCN approved the request to initially allocate the costs between NPC and SPPC using an 80/20 cost allocation, respectively. Furthermore, the PUCN granted SPPC's request for critical facility designation, thereby allowing it to qualify for incentives to be determined at a later date.

The PUCN also directed the Utilities, upon receipt of the air permit, to prepare and submit a subsequent filing in the form of a resource plan amendment ("Ely Energy Center Amendment") in which they will ask for PUCN approval to proceed with the construction of the Ely Energy Center and transmission line based on detailed engineering, construction and cost estimates, and a refined project schedule.

OTHER NEVADA MATTERS

Nevada Power Company and Sierra Pacific Power Company

RENEWABLE PORTFOLIO COMPLIANCE In April 2006, the Utilities filed their 2005 Annual Renewable Energy Portfolio Standard Report with the PUCN (the "Report"). The Report indicates that the Utilities will meet the non-solar portfolio standard upon PUCN approval of a sale from SPPC to NPC of non-solar portfolio energy credits. The Utilities requested an exemption from the PUCN for the solar portion of the portfolio standard.

In September 2006, the PUCN approved a stipulated agreement allowing NPC to purchase from SPPC non-solar portfolio energy credits to meet its 2005 compliance year requirements.

In January 2007, the PUCN approved the Annual Report of NPC and SPPC regarding compliance with the renewable energy portfolio standard for 2005 in accordance with a stipulated agreement that was filed with the PUCN in November 2006.

CALIFORNIA ELECTRIC MATTERS

Sierra Pacific Power Company

2006 ENERGY COST ADJUSTMENT CLAUSE RATE CASE In April 2006, SPPC filed with the CPUC to reset its "balancing" rate to recover a forecasted deferred energy cost balance and to increase its "offset" rate for going forward fuel and power purchases. The requested increase in the balancing rate is expected to result in $1.1 million additional revenue and the requested increase in the offset rate is expected to collect an additional $10.1 million. The total request represents an $11.2 million annual revenue increase or a 16.5% average increase to customer rates.

In October 2006, the CPUC authorized SPPC's request as filed.

2005 GENERAL RATE CASE In June 2005, SPPC filed a California General Rate Case requesting $8.1 million of new revenue from approximately 40,000 California customers. The request represents a 12.7% average increase. SPPC requested that the new rates become effective on January 1, 2006.

In August 2006, the CPUC approved a settlement agreement which, beginning September 2006, allowed SPPC to collect an estimated $4.1 million of additional general revenues from its California customers.

OTHER CALIFORNIA MATTERS

Sierra Pacific Power Company

SENATE BILL 1368 In September 2006, California enacted Senate Bill 1368 which requires, among other things, that load-bearing utilities may not undertake new long-term financial commitments for baseload generation plants if the greenhouse gas (GHG) emission rates for those plants exceed the GHG emission rate of a combined-cycle gas turbine power plant. The legislation also provides that multi-jurisdictional utilities, including SPPC, will not be subject to the substantive restrictions of Senate Bill 1368 if the CPUC finds that GHG emissions by those utilities are subject to regulatory review in at least one other state. On January 25, 2007, the CPUC issued an order finding that SPPC meets this alternative compliance requirement and that SPPC need only file annual advice letters with the CPUC attesting that it continues to meet the alternative compliance requirement.

SPPC is unable to predict the impact that future California legislative or regulatory actions relating to GHG emissions may have on SPPC.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

As of December 31, 2006, 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. 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 (dollars in thousands).

	December 31, 2006							
Expected Maturity Date	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value
LONG-TERM DEBT								
SPR								
Fixed rate	$ —	$ —	$ —	$ —	$ —	$ 549,209	$ 549,209	$ 568,541
Average interest rate	—	—	—	—	—	7.75%	7.75%	
NPC								
Fixed rate	$ 15	$ 15	$ —	$ —	$364,000	$1,776,835	$2,140,865	$2,246,234
Average interest rate	8.17%	8.17%	—	—	8.14%	6.58%	6.85%	
Variable rate	$ —	$ —	$15,000	$ —	$ —	$ 192,500	$ 207,500	$ 207,500
Average interest rate	—	—	3.63%	—	—	3.57%	3.57%	
SPPC								
Fixed rate	$2,400	$322,400	$80,600	$ —	$ —	$ 400,000	$ 805,400	$ 819,744
Average interest rate	6.40%	7.99%	5.01%	—	—	6.06%	6.73%	
Variable rate	$ —	$ —	$ —	$ —	$ —	$ 268,250	$ 268,250	$ 268,250
Average interest rate	—	—	—	—	—	3.62%	3.62%	
Total debt	$2,415	$322,415	$95,600	$ —	$364,000	$3,186,794	$3,971,224	$4,110,269

	December 31, 2005							
Expected Maturity Date	2006	2007	2008	2009	2010	Thereafter	Total	Fair Value
LONG-TERM DEBT								
SPR								
Fixed rate	$ —	$ —	$ —	$ —	$ —	$ 659,142	$ 659,142	$ 689,131
Average interest rate						7.86%	7.86%	
NPC								
Fixed rate	$ 15	$ 17	$ 13	$162,500	$ —	$1,741,048	$1,903,593	$1,979,608
Average interest rate	8.17%	8.17%	8.17%	10.88%		7.20%	7.52%	
Variable rate				$ 15,000	$150,000	$ 100,000	$ 265,000	$ 265,000
Average interest rate				1.74%	5.50%	1.74%	3.87%	
SPPC								
Fixed rate	$52,400	$2,400	$322,400	$ 80,420	$ —	$ 537,250	$ 994,870	$1,013,385
Average interest rate	6.73%	6.40%	7.99%	5.01%	—	6.75%	7.01%	
Total debt	$52,415	$2,417	$322,413	$257,920	$150,000	$3,037,440	$3,822,605	$3,947,124

Commodity Price Risk

Commodity price increases due to changes in market conditions are recovered through the deferred energy mechanism. Although the Utilities actively manage energy commodity (electric, natural gas, coal and oil) price risk through their procurement strategies, the ability to recover commodity price changes through future rates substantially mitigates commodity price risk. However, the Utilities are subject to cash flow risk due to changes in the value of their open positions and are subject to regulatory risk because the PUCN may disallow recovery for any costs that it considers imprudently incurred. The Utilities mitigate both risk associated with its open positions and regulatory risk through prudent energy supply practices which include the use of long-term fuel supply agreements, long-term purchase power agreements and derivative instruments such as forwards, options and swaps to meet the anticipated fuel and power requirements. 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, and Note 13, Commitments and Contingencies, Regulatory Contingencies, of the Notes to Financial Statements for a discussion of amounts subject to regulatory risk.

Credit Risk

The Utilities monitor and manage credit risk with their trading counterparties. Credit risk is defined as the possibility that a counterparty to one or more contracts will be unable or unwilling to fulfill its financial or physical obligations to the Utilities because of the counterparty's financial condition. The Utilities' credit risk associated with trading counterparties was approximately $31.1 million as of December 31, 2006, which decreased significantly from December 31, 2005 due to lower natural gas and power prices in 2006 compared to the high prices experienced in 2005 as a result of hurricanes in the southern United States. In the event that the trading counterparties are unable to deliver under their contracts, it may be necessary for the Utilities to purchase alternative energy at a higher market price.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Sierra Pacific Resources is responsible for establishing and maintaining adequate internal control over financial reporting. Sierra Pacific Resources' internal control system was designed to provide reasonable assurance to the company's management and Board of Directors regarding the preparation and fair presentation of published financial statements.

Although Sierra Pacific Resources is firmly committed to effective internal controls over financial reporting, internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Sierra Pacific Resources' management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2006. In making this assessment, Sierra Pacific Resources used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework. Based on our assessment we believe that, as of December 31, 2006, the Company's internal control over financial reporting is effective based on those criteria.

Sierra Pacific Resources' independent registered public accountants have issued an audit report on our assessment of the Company's internal control over financial reporting.

March 1, 2007

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

We have audited the accompanying consolidated balance sheets and statements of capitalization of Sierra Pacific Resources and subsidiaries as of December 31, 2006 and 2005, and the related consolidated income statements and statements of comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sierra Pacific Resources and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, on January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(R), and on December 31, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 158.

DELOITTE & TOUCHE LLP
Reno, Nevada
March 1, 2007

To the Board of Directors and Shareholder of
Nevada Power Company
Las Vegas, Nevada

We have audited the accompanying consolidated balance sheets and statements of capitalization of Nevada Power Company and subsidiaries as of December 31, 2006 and 2005, and the related consolidated income statements and statements of comprehensive income, common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Nevada Power Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, on December 31, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 158.

DELOITTE & TOUCHE LLP
Reno, Nevada
March 1, 2007

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

We have audited the accompanying consolidated balance sheets and statements of capitalization of Sierra Pacific Power Company and subsidiaries as of December 31, 2006 and 2005, and the related consolidated income statements and statements of comprehensive income, common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sierra Pacific Power Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, on December 31, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 158.

DELOITTE & TOUCHE LLP
Reno, Nevada
March 1, 2007

December 31,	**2006**	2005
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$7,954,337**	$6,801,916
Less accumulated provision for depreciation	**2,333,357**	2,169,316
	5,620,980	4,632,600
Construction work-in-progress	**466,018**	765,005
	6,086,998	5,397,605
Investments and other property, net (Note 4)	**34,325**	82,771
Current Assets:		
Cash and cash equivalents	**115,709**	172,735
Restricted cash and investments	**—**	67,245
Accounts receivable less allowance for uncollectible accounts:		
2006—$39,566; 2005—$36,229	**415,082**	413,234
Deferred energy costs—electric (Note 1)	**168,260**	253,697
Deferred energy costs—gas (Note 1)	**—**	5,825
Materials, supplies and fuel, at average cost	**103,757**	88,445
Risk management assets (Note 9)	**27,305**	50,226
Deferred income taxes (Note 10)	**55,546**	—
Deposits and prepayments for energy	**15,968**	45,054
Other	**31,580**	26,544
	933,207	1,123,005
Deferred Charges and Other Assets:		
Goodwill (Note 18)	**469**	22,877
Deferred energy costs—electric (Note 1)	**382,286**	255,312
Deferred energy costs—gas (Note 1)	**—**	845
Regulatory tax asset (Note 10)	**263,170**	249,261
Regulatory asset for pension plans (Note 1)	**223,218**	—
Other regulatory assets	**668,624**	568,145
Risk management assets (Note 9)	**7,586**	—
Risk management regulatory assets—net (Note 9)	**122,911**	—
Unamortized debt issuance costs	**67,106**	63,395
Other	**42,176**	107,330
	1,777,546	1,267,165
TOTAL ASSETS	**$8,832,076**	$7,870,546

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

(continued)

December 31,	**2006**	2005
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholders' equity	**$2,622,297**	$2,060,154
Preferred stock	**—**	50,000
Long-term debt	**4,001,542**	3,817,122
	6,623,839	5,927,276
Current Liabilities:		
Current maturities of long-term debt	**8,348**	58,909
Accounts payable	**282,463**	263,100
Accrued interest	**56,426**	58,585
Dividends declared	**73**	1,043
Accrued salaries and benefits	**33,146**	32,186
Current income taxes payable (Note 10)	**5,914**	3,159
Deferred income taxes (Note 10)	**—**	129,041
Risk management liabilities (Note 9)	**123,065**	16,580
Accrued taxes	**6,290**	6,540
Contract termination liabilities	**—**	129,000
Other current liabilities	**60,349**	56,724
	576,074	754,867
Commitments and Contingencies (Note 13)		
Deferred Credits and Other Liabilities:		
Deferred income taxes (Note 10)	**791,428**	451,924
Deferred investment tax credit	**35,218**	38,625
Regulatory tax liability (Note 10)	**34,075**	38,224
Customer advances for construction	**91,895**	170,061
Accrued retirement benefits	**226,420**	71,810
Risk management liabilities (Note 9)	**10,746**	—
Risk management regulatory liability—net (Note 9)	**—**	15,605
Regulatory liabilities (Note 1)	**301,903**	284,438
Other	**140,478**	117,716
	1,632,163	1,188,403
TOTAL CAPITALIZATION AND LIABILITIES	**$8,832,076**	$7,870,546

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

Year ended December 31,	**2006**	2005	2004
(dollars in thousands, except per share amounts)			
OPERATING REVENUES:			
Electric	**$ 3,144,243**	$ 2,850,694	$ 2,666,000
Gas	**210,068**	178,270	153,752
Other	**1,639**	1,278	5,044
	3,355,950	3,030,242	2,824,796
OPERATING EXPENSES:			
Operation:			
Purchased power	**1,109,440**	1,315,986	1,069,302
Fuel for power generation	**800,585**	510,736	459,478
Gas purchased for resale	**160,739**	140,850	121,526
Deferred energy costs disallowed	**—**	—	1,586
Deferral of energy costs—electric—net	**139,365**	(37,558)	143,033
Deferral of energy costs—gas—net	**6,947**	(749)	(4,136)
Impairment of goodwill	**—**	—	11,695
Reinstatement of deferred energy (Note 13)	**(178,825)**	—	—
Other	**367,198**	363,802	335,998
Maintenance	**93,172**	78,730	78,907
Depreciation and amortization	**228,875**	214,662	205,922
Taxes:			
Income taxes (Note 10)	**91,571**	39,185	22,739
Other than income	**48,086**	45,920	44,888
	2,867,153	2,671,564	2,490,938
OPERATING INCOME	**488,797**	358,678	333,858
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**18,226**	20,322	5,948
Interest accrued on deferred energy	**27,898**	27,442	25,332
Early debt conversion fees	**—**	(54,000)	—
Disallowed merger costs	**—**	—	(5,890)
Disallowed plant costs	**—**	—	(47,092)
Carrying charge for Lenzie (Note 1)	**33,440**	—	—
Gain on sale of investment	**62,927**	—	—
Other income	**37,123**	41,200	35,313
Other expense	**(23,497)**	(18,645)	(13,770)
Income (taxes)/benefits (Note 10)	**(54,034)**	(3,933)	4,689
	102,083	12,386	4,530
Total Income Before Interest Charges	**590,880**	371,064	338,388

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

(continued)

Year ended December 31,	**2006**	2005	2004
(dollars in thousands, except per share amounts)			
INTEREST CHARGES:			
Long-term debt	**294,488**	302,668	313,305
Interest for energy suppliers (Note 13)	**—**	(17,221)	(35,170)
Other	**33,719**	24,171	37,998
Allowance for borrowed funds used during construction	**(17,119)**	(24,691)	(8,587)
	311,088	284,927	307,546
INCOME FROM CONTINUING OPERATIONS	**279,792**	86,137	30,842
DISCONTINUED OPERATIONS:			
Gain on the sale of discontinued operations (net of income taxes of $(877))	**—**	—	1,629
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARY AND PREMIUM ON REDEMPTION	**2,341**	3,900	3,900
NET INCOME APPLICABLE TO COMMON STOCK	**$ 277,451**	$ 82,237	$ 28,571
Amount per share basic and diluted—(Note 16)			
Income from continuing operations	**$ 1.34**	$ 0.46	$ 0.17
Gain on sale of discontinued operations	**$ —**	$ —	$ 0.01
Net income applicable to common stock	**$ 1.33**	$ 0.44	$ 0.16
Weighted average shares of common stock outstanding—basic	**208,531,134**	185,548,314	183,080,475
Weighted average shares of common stock outstanding—diluted	**209,020,896**	185,932,504	183,400,303

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

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

Year ended December 31,	**2006**	2005	2004
(dollars in thousands)			
NET INCOME APPLICABLE TO COMMON STOCK	**$277,451**	$82,237	$28,571
OTHER COMPREHENSIVE INCOME (LOSS)			
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $1,155 and $(950) in 2005 and 2004, respectively)	**—**	(2,146)	1,763
Minimum pension liability adjustment (net of taxes of $(1,132), $1,569 and $(15,486) in 2006, 2005 and 2004, respectively)	**2,106**	(4,311)	29,404
OTHER COMPREHENSIVE INCOME (LOSS)	**2,106**	(6,457)	31,167
COMPREHENSIVE INCOME	**$279,557**	$75,780	$59,738

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

Year ended December 31,	**2006**	2005	2004
(dollars in thousands)			
COMMON STOCK:			
Balance at Beginning of Year	**$ 200,792**	$ 117,469	$ 117,236
Stock issuance/exchange, CSIP, DRP, ESPP and other	**20,238**	83,323	233
Balance at End of Year	**221,030**	200,792	117,469
OTHER PAID-IN CAPITAL:			
Balance at Beginning of Year	**2,220,896**	1,818,453	1,815,202
Premium on issuance/exchange of common stock	**260,600**	405,767	563
Common stock issuance costs	**(857)**	(6,486)	—
Revaluation of investment	**—**	119	1,690
Value of derivative transferred to equity	**—**	—	—
CSIP, DRP, ESPP and other	**2,605**	3,043	998
Balance at End of Year	**2,483,244**	2,220,896	1,818,453
RETAINED EARNINGS (DEFICIT):			
Balance at Beginning of Year	**(355,883)**	(438,112)	(466,683)
Net income applicable to common stock	**277,451**	82,237	28,571
Common stock dividends declared, net of adjustments	**—**	(8)	—
Balance at End of Year	**(78,432)**	(355,883)	(438,112)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**(5,651)**	806	(30,361)
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities			
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $1,155 and $(950) in 2005 and 2004, respectively)	**—**	(2,146)	1,763
Minimum pension liability adjustment (net of taxes of $(1,132), $1,569 and $(15,486) in 2006, 2005 and 2004, respectively)	**2,106**	(4,311)	29,404
Balance at End of Year	**(3,545)**	(5,651)	806
TOTAL COMMON SHAREHOLDERS' EQUITY AT END OF YEAR	**$2,622,297**	$2,060,154	$1,498,616

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

Year ended December 31,	**2006**	2005	2004
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income applicable to common stock	**$ 277,451**	$ 82,237	$ 28,571
Non-cash items included in net income (loss):			
Depreciation and amortization	**228,875**	214,662	205,922
Deferred taxes and deferred investment tax credit	**136,026**	41,609	33,690
AFUDC	**(18,226)**	(45,013)	(14,536)
Amortization of deferred energy costs—electric	**166,821**	188,221	265,418
Amortization of deferred energy costs—gas	**6,234**	1,446	3,242
Deferred energy costs disallowed	**—**	—	1,586
Goodwill impairment	**—**	—	11,695
Plant costs disallowed	**—**	—	47,092
Reinstatement of deferred energy	**(178,825)**	—	—
Carrying charge on Lenzie plant	**(33,440)**	—	—
Gain on sale of investment	**(62,927)**	—	—
Impairment of assets of subsidiary	**—**	—	10,997
Gain on sale of discontinued operations	**—**	—	(2,506)
Other	**24,650**	(219)	(23,453)
Changes in certain assets and liabilities:			
Accounts receivable	**(43,214)**	(92,452)	(19,198)
Deferral of energy costs—electric	**(54,737)**	(241,103)	(152,140)
Deferral of energy costs—gas	**436**	(2,519)	(7,480)
Deferral of energy costs—terminated suppliers	**8,741**	218,040	4,551
Materials, supplies and fuel	**(15,312)**	(12,251)	3,331
Other current assets	**24,050**	20,663	5,721
Accounts payable	**(2,739)**	55,985	13,623
Payment to terminating supplier	**(65,368)**	—	(61,129)
Proceeds from claim on terminating supplier	**41,365**	—	—
Other current liabilities	**2,356**	(162,416)	20,306
Risk management assets and liabilities	**(5,950)**	(6,685)	8,487
Other assets	**(10,122)**	(9,950)	6,168
Other liabilities	**3,297**	(15,659)	(42,476)
Net Cash from Operating Activities	**429,442**	234,596	347,482
CASH FLOWS USED BY INVESTING ACTIVITIES:			
Additions to utility plant	**(986,019)**	(686,394)	(614,411)
AFUDC	**18,226**	45,013	14,536
Customer advances for construction	**17,348**	27,358	16,197
Contributions in aid of construction	**38,792**	23,351	26,457
Proceeds from sale of investment	**99,730**	—	—
Proceeds from sale of discontinued operations	**—**	—	4,471
Investments in subsidiaries and other property—net	**8,423**	10,200	16,299
Net Cash used by Investing Activities	**(803,500)**	(580,472)	(536,451)

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

(continued)

Year ended December 31,	**2006**	2005	2004
(dollars in thousands)			
CASH FLOWS FROM FINANCING ACTIVITIES:			
Increase in short-term borrowings	**—**	—	(25,000)
Change in restricted cash and investments	**3,612**	23,711	27,382
Proceeds from issuance of long-term debt	**2,491,883**	370,211	965,000
Retirement of long-term debt	**(2,407,745)**	(373,938)	(693,538)
Redemption of preferred stock	**(51,366)**	—	—
Sale of common stock, net of issuance cost	**282,594**	236,208	3,488
Dividends paid	**(1,945)**	(3,911)	(3,821)
Net Cash from Financing Activities	**317,033**	252,281	273,511
Net Increase (Decrease) in Cash and Cash Equivalents	**(57,025)**	(93,595)	84,542
Beginning Balance in Cash and Cash Equivalents	**172,734**	266,330	181,789
Ending Balance in Cash and Cash Equivalents	**$ 115,709**	$ 172,735	$ 266,331
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid during period for:			
Interest	**$ 338,665**	$ 330,889	$ 339,718
Income taxes	**$ 4,726**	$ —	$ —
NON-CASH ACTIVITIES:			
Exchange of Convertible Debt for SPR Common Stock	**$ —**	$ 248,168	$ —

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

December 31,	**2006**	2005
(dollars in thousands, except per share amounts)		
COMMON SHAREHOLDER'S EQUITY:		
Common stock, $1.00 par value, authorized 350 million; issued and outstanding 2006: 221,030,000 shares; issued and outstanding 2005: 200,792,000 share	**$ 221,030**	$ 200,792
Other paid-in capital	**2,483,244**	2,220,896
Retained deficit	**(78,432)**	(355,883)
Accumulated other comprehensive income (loss)	**(3,545)**	(5,651)
Total Common Shareholder's Equity	**2,622,297**	2,060,154
PREFERRED STOCK OF SUBSIDIARIES:		
Not subject to mandatory redemption; 2005: 2,000,000 shares outstanding; $25 stated value		
SPPC Class A Series 1; $1.95 dividend	**—**	50,000
LONG-TERM DEBT:		
SECURED DEBT		
First Mortgage Bonds		
8.50% NPC Series Z due 2023	**—**	35,000
Debt Secured by First Mortgage Bonds		
Revenue Bonds		
Nevada Power Company		
6.60% NPC Series 1992B due 2019	**—**	39,500
6.70% NPC Series 1992A due 2022	**—**	105,000
7.20% NPC Series 1992C due 2022	**—**	78,000
Sierra Pacific Power Company		
6.35% SPPC Series 1992B due 2012	**—**	1,000
6.55% SPPC Series 1987 due 2013	**—**	39,500
6.30% SPPC Series 1987 due 2014	**—**	45,000
6.65% SPPC Series 1987 due 2017	**—**	92,500
6.55% SPPC Series 1990 due 2020	**—**	20,000
6.30% SPPC Series 1992A due 2022	**—**	10,250
5.90% SPPC Series 1993A due 2023	**—**	9,800
5.90% SPPC Series 1993B due 2023	**—**	30,000
6.70% SPPC Series 1992 due 2032	**—**	21,200
Medium Term Notes		
Sierra Pacific Power Company		
6.62% to 6.83% SPPC Series C due 2006	**—**	50,000
6.95% to 8.61% SPPC Series A due 2022	**—**	110,000
7.10% to 7.14% SPPC Series B due 2023	**—**	58,000
Subtotal	**—**	744,750
Debt Secured by General and Refunding Mortgage Securities		
Nevada Power Company		
10.88% NPC Series E due 2009	**—**	162,500
8.25% NPC Series A due 2011	**350,000**	350,000
6.50% NPC Series I due 2012	**130,000**	130,000
9.00% NPC Series G due 2013	**227,500**	227,500
5.875% NPC Series L due 2015	**250,000**	250,000
5.95% NPC Series M due 2016	**210,000**	—
6.65% NPC Series N due 2036	**370,000**	—
6.50% NPC Series O due 2018	**325,000**	—
Subtotal	**1,862,500**	1,120,000

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

(continued)

December 31,	**2006**	2005
(dollars in thousands, except per share amounts)		
Sierra Pacific Power Company		
8.00% SPPC Series A due 2008	**320,000**	320,000
6.25% SPPC Series H due 2012	**100,000**	100,000
6.00% SPPC Series M due 2016	**300,000**	—
5.00% SPPC Series 2001 due 2036	**80,000**	80,000
Subtotal	**800,000**	500,000
Variable Rate Notes		
Nevada Power Company		
NPC PCRB Series 2000B due 2009	**15,000**	15,000
NPC IDRB Series 2000A due 2020	**100,000**	100,000
NPC PCRB Series 2006 due 2036	**39,500**	—
NPC PCRB Series 2006A due 2032	**40,000**	—
NPC PCRB Series 2006B due 2039	**13,000**	—
NPC Revolving Credit Facility	**—**	150,000
Subtotal	**207,500**	265,000
Sierra Pacific Power Company		
SPPC PCRB Series 2006 due 2029	**49,750**	—
SPPC PCRB Series 2006A due 2031	**58,700**	—
SPPC PCRB Series 2006B due 2036	**75,000**	—
SPPC PCRB Series 2006C due 2036	**84,800**	—
Subtotal	**268,250**	—
UNSECURED DEBT		
Revenue Bonds		
Nevada Power Company		
5.30% NPC Series 1995D due 2011	**14,000**	14,000
5.35% NPC Series 1995E due 2022	**—**	13,000
5.45% NPC Series 1995D due 2023	**6,300**	6,300
5.50% NPC Series 1995C due 2030	**44,000**	44,000
5.60% NPC Series 1995A due 2030	**76,750**	76,750
5.90% NPC Series 1995B due 2030	**85,000**	85,000
5.80% NPC Series 1997B due 2032	**—**	20,000
5.90% NPC Series 1997A due 2032	**52,285**	52,285
6.38% NPC Series 1996 due 2036	**—**	20,000
Subtotal	**278,335**	331,335
Other Notes		
Sierra Pacific Resources		
7.803% SPR Senior Notes due 2012	**74,170**	99,142
8.625% SPR Notes due 2014	**250,039**	335,000
6.75% SPR Senior Notes due 2017	**225,000**	225,000
Subtotal, excluding current portion	**549,209**	659,142
Unamortized bond premium and discount, net	**(11,813)**	(3,495)
Nevada Power Company		
8.2% Junior Subordinated Debentures of NPC, due 2037	**—**	122,548
7.75% Junior Subordinated Debentures of NPC, due 2038	**—**	72,165
Subtotal	**—**	194,713
Obligations under capital leases	**50,479**	56,921
Current maturities and sinking fund requirements	**(8,348)**	(58,909)
Other, excluding current portion	**5,430**	7,665
Total Long-Term Debt	**4,001,542**	3,817,122
TOTAL CAPITALIZATION	**$6,623,839**	$5,927,276

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

December 31,	**2006**	2005
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$5,187,665**	$4,106,489
Less accumulated provision for depreciation	**1,276,192**	1,128,209
	3,911,473	2,978,280
Construction work-in-progress	**238,518**	698,206
	4,149,991	3,676,486
Investments and other property, net (Note 4)	**22,176**	29,249
Current Assets:		
Cash and cash equivalents	**36,633**	98,681
Restricted cash	**—**	52,374
Accounts receivable less allowance for uncollectible accounts:		
2006—$32,834; 2005—$30,386	**244,623**	232,086
Accounts receivable, affiliated companies	**—**	3,738
Deferred energy costs—electric (Note 1)	**129,304**	186,355
Materials, supplies and fuel, at average cost	**60,754**	46,835
Risk management assets (Note 9)	**16,378**	22,404
Deferred income taxes (Note 10)	**72,294**	—
Deposits and prepayments for energy	**7,056**	16,303
Other	**19,901**	16,075
	586,943	674,851
Deferred Charges and Other Assets:		
Deferred energy costs—electric (Note 1)	**359,589**	214,587
Regulatory tax asset (Note 10)	**153,471**	155,304
Regulatory asset for pension plans (Note 1)	**113,646**	—
Other regulatory assets (Note 1)	**440,369**	362,567
Risk management assets	**5,379**	—
Risk management regulatory assets—net (Note 9)	**83,886**	—
Unamortized debt issuance costs	**38,856**	37,157
Other	**33,209**	23,720
	1,228,405	793,335
TOTAL ASSETS	**$5,987,515**	$5,173,921

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

(continued)

December 31,	**2006**	2005
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholder's equity	**$2,172,198**	$1,762,089
Long-term debt	**2,380,139**	2,214,063
	4,552,337	3,976,152
Current Liabilities:		
Current maturities of long-term debt	**5,948**	6,509
Accounts payable	**148,003**	164,169
Accounts payable, affiliated companies	**20,656**	—
Accrued interest	**37,010**	33,031
Dividends declared	**13,545**	397
Accrued salaries and benefits	**14,989**	15,537
Current income taxes payable (Note 10)	**3,981**	3,159
Intercompany income taxes payable	**884**	—
Deferred income taxes (Note 10)	**—**	57,392
Risk management liabilities (Note 9)	**84,674**	10,125
Accrued taxes	**2,671**	2,817
Contract termination liabilities	**—**	89,784
Other current liabilities	**48,225**	46,425
	380,586	429,345
Commitments and Contingencies (Note 13)		
Deferred Credits and Other Liabilities:		
Deferred income taxes (Note 10)	**599,747**	362,973
Deferred investment tax credit	**15,213**	16,832
Regulatory tax liability (Note 10)	**13,451**	15,068
Customer advances for construction	**60,040**	98,056
Accrued retirement benefits	**90,474**	22,203
Risk management liabilities (Note 9)	**7,061**	—
Risk management regulatory liability—net (Note 9)	**—**	590
Regulatory liabilities (Note 1)	**171,298**	173,527
Other	**97,308**	79,175
	1,054,592	768,424
TOTAL CAPITALIZATION AND LIABILITIES	**$5,987,515**	$5,173,921

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

Year ended December 31,	**2006**	2005	2004
(dollars in thousands)			
OPERATING REVENUES:			
Electric	**$2,124,081**	$1,883,267	$1,784,092
OPERATING EXPENSES:			
Operation:			
Purchased power	**764,850**	963,888	764,347
Fuel for power generation	**552,959**	277,083	235,404
Deferred energy costs disallowed	**—**	—	1,586
Deferral of energy costs—net	**92,322**	(45,668)	135,973
Reinstatement of deferred energy (Note 13)	**(178,825)**	—	—
Other	**218,120**	211,039	183,736
Maintenance	**61,899**	52,040	57,030
Depreciation and amortization	**141,585**	124,098	118,841
Taxes:			
Income taxes (Note 10)	**91,781**	46,425	45,135
Other than income	**28,118**	25,535	25,550
	1,772,809	1,654,440	1,567,602
OPERATING INCOME	**351,272**	228,827	216,490
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**11,755**	18,683	4,230
Interest accrued on deferred energy	**21,902**	20,350	20,199
Disallowed merger costs	**—**	—	(3,961)
Carrying charge for Lenzie (Note 1)	**33,440**	—	—
Other income	**16,992**	25,626	22,844
Other expense	**(8,480)**	(8,525)	(6,665)
Income taxes (Note 10)	**(25,729)**	(17,570)	(11,437)
	49,880	38,564	25,210
Total Income Before Interest Charges	**401,152**	267,391	241,700
INTEREST CHARGES:			
Long-term debt	**171,188**	159,106	152,764
Interest for Energy Suppliers (Note 13)	**—**	(14,825)	(24,171)
Other	**17,038**	13,563	14,533
Allowance for borrowed funds used during construction	**(11,614)**	(23,187)	(5,738)
	176,612	134,657	137,388
NET INCOME	**$ 224,540**	$ 132,734	$ 104,312

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

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

Year ended December 31,	**2006**	2005	2004
(dollars in thousands)			
NET INCOME	**$224,540**	$132,734	$104,312
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $785 and $(688) in 2005 and 2004, respectively)	**—**	(1,460)	1,277
Minimum pension liability adjustment (net of taxes of $(520), $740 and $(1,205) in 2006, 2005 and 2004, respectively)	**965**	(2,769)	2,239
OTHER COMPREHENSIVE INCOME (LOSS)	**965**	(4,229)	3,516
COMPREHENSIVE INCOME	**$225,505**	$128,505	$107,828

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

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

December 31,	**2006**	2005	2004
(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	**1,808,848**	1,576,794	1,377,106
Transfer of goodwill	**—**	—	197,998
Revaluation of investment	**—**	119	1,690
Transfer of pension assets	**33,521**	—	—
Capital infusion from parent	**200,000**	231,935	—
Balance at End of Year	**2,042,369**	1,808,848	1,576,794
RETAINED EARNINGS (DEFICIT):			
Balance at Beginning of Year	**(43,422)**	(140,898)	(199,837)
Income for the year	**224,540**	132,734	104,312
Common stock dividends declared	**(48,917)**	(35,258)	(45,373)
Balance at End of Year	**132,201**	(43,422)	(140,898)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**(3,338)**	891	(2,625)
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $785 and $(688) in 2005 and 2004, respectively)	**—**	(1,460)	1,277
Minimum pension liability adjustment (net of taxes of $(520), $740 and $(1,205) in 2006, 2005 and 2004, respectively)	**965**	(2,769)	2,239
Balance at End of Year	**(2,373)**	(3,338)	891
TOTAL COMMON SHAREHOLDER'S EQUITY AT END OF YEAR	**$2,172,198**	$ 1,762,089	$ 1,436,788

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

Year ended December 31,	2006	2005	2004
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	**$ 224,540**	$ 132,734	$ 104,312
Non-cash items included in net loss:			
Depreciation and amortization	**141,585**	124,098	118,841
Deferred taxes and deferred investment tax credit	**107,392**	86,910	57,066
AFUDC	**(11,755)**	(41,870)	(9,969)
Amortization of deferred energy costs	**120,499**	131,471	228,765
Deferred energy costs disallowed	**—**	—	1,586
Reinstatement of deferred energy	**(178,825)**	—	
Carrying charge on Lenzie plant	**(33,440)**	—	—
Other	**3,394**	(7,433)	(44,149)
Changes in certain assets and liabilities:			
Accounts receivable	**(35,191)**	(57,746)	(7,247)
Deferral of energy costs	**(49,982)**	(186,338)	(117,543)
Deferral of energy costs—terminated suppliers	**3,896**	155,119	4,551
Materials, supplies and fuel	**(13,919)**	(1,977)	(3,782)
Other current assets	**5,421**	14,434	14,522
Accounts payable	**(2,431)**	30,855	10,350
Payment to terminating supplier	**(37,410)**	—	(50,311)
Proceeds from claim on terminating supplier	**26,391**	—	—
Other current liabilities	**5,083**	(107,575)	10,504
Risk management assets and liabilities	**(2,219)**	(6,597)	4,454
Other assets	**(9,902)**	(9,950)	6,168
Other liabilities	**(2,946)**	(31,926)	14,522
Net Cash from Operating Activities	**260,181**	224,209	342,640
CASH FLOWS USED BY INVESTING ACTIVITIES:			
Additions to utility plant	**(670,441)**	(546,748)	(482,484)
AFUDC	**11,755**	41,870	9,969
Customer advances for construction	**10,417**	18,813	8,067
Contributions in aid of construction	**21,241**	8,544	10,703
Investments in subsidiaries and other property—net	**7,363**	1,875	5,404
Net Cash used by Investing Activities	**(619,665)**	(475,646)	(448,341)
CASH FLOWS FROM (USED BY) FINANCING ACTIVITIES:			
Change in restricted cash and investments	**—**	—	2,600
Proceeds from issuance of long-term debt	**1,687,726**	150,000	530,000
Retirement of long-term debt	**(1,554,521)**	(238,486)	(283,498)
Additional investment by parent company	**200,000**	230,541	—
Dividends paid	**(35,769)**	(35,260)	(44,975)
Net Cash from Financing Activities	**297,436**	106,795	204,127
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS:	**(62,048)**	(144,642)	98,426
Beginning Balance in Cash and Cash Equivalents	**98,681**	243,323	144,897
Ending Balance in Cash and Cash Equivalents	**$ 36,633**	$ 98,681	$ 243,323
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid during period for:			
Interest	**$ 190,023**	$ 173,775	$ 161,126
Income taxes	**$ 4,714**	$ —	$ —
NON-CASH ACTIVITIES:			
Transfer of Regulatory Asset	**$ —**	$ —	$ 197,998

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

December 31,	**2006**	2005
(dollars in thousands, except per share amounts)		
COMMON SHAREHOLDER'S EQUITY:		
Common stock, $1.00 par value, 1,000 shares authorized, issued and outstanding	**$ 1**	$ 1
Other paid-in capital	**2,042,369**	1,808,848
Retained earning (deficit)	**132,201**	(43,422)
Accumulated other comprehensive income (loss)	**(2,373)**	(3,338)
Total Common Shareholder's Equity	**2,172,198**	1,762,089
LONG-TERM DEBT:		
SECURED DEBT		
First Mortgage Bonds		
8.50% Series Z due 2023	**—**	35,000
Debt Secured by First Mortgage Bonds		
Revenue Bonds		
6.60% Series 1992B due 2019	**—**	39,500
6.70% Series 1992A due 2022	**—**	105,000
7.20% Series 1992C due 2022	**—**	78,000
Subtotal	**—**	257,500
Debt Secured by General and Refunding Mortgage Securities		
10.88% Series E due 2009	**—**	162,500
8.25% Series A due 2011	**350,000**	350,000
6.50% Series I due 2012	**130,000**	130,000
9.00% Series G due 2013	**227,500**	227,500
5.875% Series L due 2015	**250,000**	250,000
5.95% Series M due 2016	**210,000**	—
6.65% Series N due 2036	**370,000**	—
6.00% Series O due 2018	**325,000**	—
Subtotal	**1,862,500**	1,120,000
Variable Rate Notes		
PCRB Series 2000B due 2009	**15,000**	15,000
IDRB Series 2000A due 2020	**100,000**	100,000
PCRB Series 2006 due 2036	**39,500**	—
PCRB Series 2006A due 2032	**40,000**	—
PCRB Series 2006B due 2039	**13,000**	—
Revolving Credit Facility	**—**	150,000
Subtotal	**207,500**	265,000

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

(continued)

December 31,	**2006**	2005
(dollars in thousands, except per share amounts)		
UNSECURED DEBT		
Revenue Bonds		
5.30% Series 1995D due 2011	**14,000**	14,000
5.35% Series 1995E due 2022	**—**	13,000
5.45% Series 1995D due 2023	**6,300**	6,300
5.50% Series 1995C due 2030	**44,000**	44,000
5.60% Series 1995A due 2030	**76,750**	76,750
5.90% Series 1995B due 2030	**85,000**	85,000
5.80% Series 1997B due 2032	**—**	20,000
5.90% Series 1997A due 2032	**52,285**	52,285
6.38% Series 1996 due 2036	**—**	20,000
Subtotal	**278,335**	331,335
Unamortized bond premium and discount, net	**(12,757)**	(4,942)
8.2% Junior Subordinated Debentures due 2037	**—**	122,548
7.75% Junior Subordinated Debentures due 2038	**—**	72,165
Subtotal	**—**	194,713
Obligations under capital leases	**50,479**	56,921
Current maturities and sinking fund requirements	**(5,948)**	(6,509)
Other, excluding current portion	**30**	45
Total Long-Term Debt	**2,380,139**	2,214,063
TOTAL CAPITALIZATION	**$4,552,337**	$ 3,976,152

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

December 31,	**2006**	2005
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$2,766,672**	$2,695,427
Less accumulated provision for depreciation	**1,057,165**	1,041,107
	1,709,507	1,654,320
Construction work-in-progress	**227,500**	66,799
	1,937,007	1,721,119
Investments and other property, net (Note 4)	**609**	842
Current Assets:		
Cash and cash equivalents	**53,260**	38,153
Restricted cash	**—**	14,871
Accounts receivable less allowance for uncollectible accounts:		
2006—$6,732; 2005—$5,842	**170,106**	180,973
Accounts receivable, affiliated companies	**—**	40,278
Deferred energy costs—electric (Note 1)	**38,956**	67,342
Deferred energy costs—gas (Note 1)	**—**	5,825
Materials, supplies and fuel, at average cost	**42,990**	41,608
Risk management assets (Note 9)	**10,927**	27,822
Deposits and prepayments for energy	**8,912**	28,751
Other	**11,184**	9,547
	336,335	455,170
Deferred Charges and Other Assets:		
Deferred energy costs—electric (Note 1)	**22,697**	40,725
Deferred energy costs—gas (Note 1)	**—**	845
Regulatory tax asset (Note 10)	**109,699**	93,957
Regulatory asset for pension plans (Note 1)	**106,666**	—
Other regulatory assets	**228,255**	205,578
Risk management assets (Note 9)	**2,207**	—
Risk management regulatory assets—net (Note 9)	**39,025**	—
Unamortized debt issuance costs	**17,981**	12,693
Other	**7,356**	15,372
	533,886	369,170
TOTAL ASSETS	**$2,807,837**	$2,546,301

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

(continued)

December 31,	**2006**	2005
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholder's equity	**$ 884,737**	$ 727,777
Preferred stock	**—**	50,000
Long-term debt	**1,070,858**	941,804
	1,955,595	1,719,581
Current Liabilities:		
Current maturities of long-term debt	**2,400**	52,400
Accounts payable	**89,743**	56,661
Accounts payable, affiliated companies	**11,769**	—
Accrued interest	**7,200**	10,993
Dividends declared	**6,736**	968
Accrued salaries and benefits	**15,209**	14,032
Intercompany income taxes payable (Note 10)	**9,055**	49,673
Deferred income taxes (Note 10)	**8,881**	21,832
Risk management liabilities (Note 9)	**38,391**	6,455
Accrued taxes	**3,407**	3,541
Contract termination liabilities	**—**	39,216
Other current liabilities	**12,125**	10,299
	204,916	266,070
Commitments and Contingencies (Note 13)		
Deferred Credits and Other Liabilities:		
Deferred income taxes (Note 10)	**278,515**	244,244
Deferred investment tax credit	**20,005**	21,793
Regulatory tax liability (Note 10)	**20,624**	23,156
Customer advances for construction	**31,855**	72,005
Accrued retirement benefits	**124,254**	40,269
Risk management liabilities (Note 9)	**3,685**	—
Risk management regulatory liability—net (Note 9)	**—**	15,015
Regulatory liabilities (Note 1)	**130,605**	110,911
Other	**37,783**	33,257
	647,326	560,650
TOTAL CAPITALIZATION AND LIABILITIES	**$2,807,837**	$2,546,301

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

Year ended December 31,	**2006**	2005	2004
(dollars in thousands)			
OPERATING REVENUES:			
Electric	**$1,020,162**	$ 967,427	$ 881,908
Gas	**210,068**	178,270	153,752
	1,230,230	1,145,697	1,035,660
OPERATING EXPENSES:			
Operation:			
Purchased power	**344,590**	352,098	304,955
Fuel for power generation	**247,626**	233,653	224,074
Gas purchased for resale	**160,739**	140,850	121,526
Deferral of energy costs—electric—net	**47,043**	8,110	7,060
Deferral of energy costs—gas—net	**6,947**	(749)	(4,136)
Other	**141,350**	131,901	128,091
Maintenance	**31,273**	26,690	21,877
Depreciation and amortization	**87,279**	90,569	86,806
Taxes:			
Income taxes (Note 10)	**23,570**	26,038	14,978
Other than income	**19,796**	20,233	19,184
	1,110,213	1,029,393	924,415
OPERATING INCOME	**120,017**	116,304	111,245
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**6,471**	1,639	1,718
Interest accrued on deferred energy	**5,996**	7,092	5,133
Disallowed merger costs	**—**	—	(1,929)
Plant costs disallowed	**—**	—	(47,092)
Other income	**9,412**	5,940	3,406
Other expense	**(8,422)**	(7,493)	(5,726)
Income (taxes)/benefits (Note 10)	**(4,259)**	(2,341)	14,653
	9,198	4,837	(29,837)
Total Income Before Interest Charges	**129,215**	121,141	81,408
INTEREST CHARGES:			
Long-term debt	**71,869**	69,240	71,312
Interest for Energy Suppliers (Note 13)	**—**	(2,396)	(10,999)
Other	**5,142**	3,727	5,367
Allowance for borrowed funds used during construction and capitalized interest	**(5,505)**	(1,504)	(2,849)
	71,506	69,067	62,831
NET INCOME	**57,709**	52,074	18,577
Dividend requirements and premium on redemption of preferred stock	**2,341**	3,900	3,900
Earnings applicable to common stock	**$ 55,368**	$ 48,174	$ 14,677

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

Year ended December 31,	**2006**	2005	2004
(dollars in thousands)			
NET INCOME	**$57,709**	$52,074	$18,577
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $370 and $(323) in 2005 and 2004, respectively)	**—**	(686)	600
Minimum pension liability adjustment (net of taxes of $(462), $632 and $65 in 2006, 2005 and 2004, respectively)	**861**	(1,173)	(123)
OTHER COMPREHENSIVE INCOME (LOSS)	**861**	(1,859)	477
COMPREHENSIVE INCOME	**$58,570**	$50,215	$19,054

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

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

December 31,	**2006**	2005	2004
(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	**810,103**	810,103	713,633
Transfer of goodwill (Note 19)	**18,888**	—	96,470
Transfer of pension assets	**31,462**	—	—
Capital infusion from parent	**75,000**	—	—
Balance at End of Year	**935,453**	810,103	810,103
RETAINED EARNINGS (DEFICIT):			
Balance at Beginning of Year	**(80,538)**	(104,779)	(119,456)
Income (loss) from continuing operations before preferred dividends	**57,709**	52,074	18,577
Preferred stock redemption	**(1,366)**	—	—
Preferred stock dividends declared	**(975)**	(3,900)	(3,900)
Common stock dividends declared	**(24,619)**	(23,933)	—
Balance at End of Year	**(49,789)**	(80,538)	(104,779)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**(1,792)**	67	(410)
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $370 and $(323) in 2005 and 2004, respectively)	**—**	(686)	600
Minimum pension liability adjustment (net of taxes of $(462), $632 and $65 in 2006, 2005 and 2004, respectively)	**861**	(1,173)	(123)
Balance at End of Year	**(931)**	(1,792)	67
TOTAL COMMON SHAREHOLDER'S EQUITY AT END OF YEAR	**$884,737**	$ 727,777	$ 705,395

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

Year ended December 31,	**2006**	2005	2004
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	**$ 57,709**	$ 52,074	$ 18,577
Non-cash items included in net income (loss):			
Depreciation and amortization	**87,279**	90,569	86,806
Deferred taxes and deferred investment tax credit	**(39,361)**	209	11,640
AFUDC	**(6,471)**	(3,143)	(4,567)
Amortization of deferred energy costs—electric	**46,322**	56,750	36,653
Amortization of deferred energy costs—gas	**6,234**	1,446	3,241
Plant costs disallowed	**—**	—	47,092
Other	**16,935**	318	474
Changes in certain assets and liabilities:			
Accounts receivable	**36,171**	(11,631)	(19,677)
Deferral of energy costs—electric	**(4,755)**	(54,765)	(34,598)
Deferral of energy costs—gas	**436**	(2,519)	(7,480)
Deferral of energy costs—terminated suppliers	**4,845**	62,921	—
Materials, supplies and fuel	**(1,382)**	(10,272)	7,113
Other current assets	**18,204**	3,106	(10,086)
Accounts payable	**19,670**	11,573	2,153
Payment to terminating supplier	**(27,958)**	—	(10,818)
Proceeds from claim on terminating supplier	**14,974**	—	—
Other current liabilities	**(925)**	(48,603)	5,567
Risk management assets and liabilities	**(3,731)**	(88)	4,033
Other assets	**(220)**	—	—
Other liabilities	**6,461**	12,186	(8,844)
Net Cash from Operating Activities	**230,437**	160,131	127,279
CASH FLOWS (USED BY) INVESTING ACTIVITIES:			
Additions to utility plant	**(315,578)**	(139,646)	(131,927)
AFUDC	**6,471**	3,143	4,567
Customer advances for construction	**6,931**	8,545	8,130
Contributions in aid of construction	**17,551**	14,807	15,754
Investments in subsidiaries and other property—net	**233**	157	(82)
Net Cash used by Investing Activities	**(284,392)**	(112,994)	(103,558)
CASH FLOWS FROM (USED BY) FINANCING ACTIVITIES:			
Decrease in short-term borrowings	**—**	—	(25,000)
Change in restricted cash and investments	**3,612**	2,034	3,130
Proceeds from issuance of long-term debt	**804,157**	—	100,000
Retirement of long-term debt	**(742,514)**	(2,504)	(99,491)
Redemption of preferred stock	**(51,366)**	—	—
Investment by parent company	**75,000**	—	—
Dividends paid	**(19,827)**	(27,833)	(3,900)
Net Cash from (used by) Financing Activities	**69,062**	(28,303)	(25,261)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS:	**15,107**	18,834	(1,540)
Beginning Balance in Cash and Cash Equivalents	**38,153**	19,319	20,859
Ending Balance in Cash and Cash Equivalents	**$ 53,260**	$ 38,153	$ 19,319
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid during period for:			
Interest	**$ 83,327**	$ 71,496	$ 77,529
Income taxes	**$ 12**	$ —	$ —
NON-CASH ACTIVITIES:			
Transfer of Regulatory Asset (Note 18)	**$ 18,888**	$ —	$ 96,470

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

December 31,	**2006**	2005
(dollars in thousands, except per share amounts)		
COMMON SHAREHOLDER'S EQUITY:		
Common stock, $3.75 par value, 20,000,000 shares authorized, 1,000 shares issued and outstanding	**$ 4**	$ 4
Other paid-in capital	**935,453**	810,103
Retained deficit	**(49,789)**	(80,538)
Accumulated other comprehensive income (loss)	**(931)**	(1,792)
Total Common Shareholder's Equity	**884,737**	727,777
CUMULATIVE PREFERRED STOCK:		
Not subject to mandatory redemption; 2,000,000 shares outstanding; $25 stated value	**—**	50,000
SPPC Class A Series 1; $1.95 dividend		
LONG-TERM DEBT:		
SECURED DEBT		
Debt Secured by First Mortgage Bonds		
Revenue Bonds		
6.35% Series 1992B due 2012	**—**	1,000
6.55% Series 1987 due 2013	**—**	39,500
6.30% Series 1987 due 2014	**—**	45,000
6.65% Series 1987 due 2017	**—**	92,500
6.55% Series 1990 due 2020	**—**	20,000
6.30% Series 1992A due 2022	**—**	10,250
5.90% Series 1993A due 2023	**—**	9,800
5.90% Series 1993B due 2023	**—**	30,000
6.70% Series 1992 due 2032	**—**	21,200
Medium Term Notes		
6.62% to 6.83% Series C due 2006	**—**	50,000
6.95% to 8.61% Series A due 2022	**—**	110,000
7.10% to 7.14% Series B due 2023	**—**	58,000
Subtotal	**—**	487,250
Debt Secured by General and Refunding Mortgage Securities		
8.00% Series A due 2008	**320,000**	320,000
6.25% Series H due 2012	**100,000**	100,000
6.00% Series M due 2016	**300,000**	—
5.00% Series 2001 due 2036	**80,000**	80,000
Subtotal	**800,000**	500,000
Variable Rate Notes		
PCRB Series 2006 due 2029	**49,750**	—
PCRB Series 2006A due 2031	**58,700**	—
PCRB Series 2006B due 2036	**75,000**	—
PCRB Series 2006C due 2036	**84,800**	—
Subtotal	**268,250**	—
UNSECURED DEBT		
Unamortized bond premium and discount, net	**(392)**	(666)
Current maturities and sinking fund requirements	**(2,400)**	(52,400)
Other, excluding current portion	**5,400**	7,620
Total Long-Term Debt	**1,070,858**	941,804
TOTAL CAPITALIZATION	**$1,955,595**	$1,719,581

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

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Basis of Presentation

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). In 2004, certain operations of SPC are discontinued operations and as such are reported separately in the financial statements. 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.

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.

NPC is an operating public utility that provides electric service in Clark County in southern Nevada. The assets of NPC represent approximately 68% of the consolidated assets of SPR at December 31, 2006. NPC provides electricity to approximately 807,000 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 NPC's wholly-owned subsidiary, Nevada Electric Investment Company (NEICO).

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 31% of the consolidated assets of SPR at December 31, 2006. SPPC provides electricity to approximately 361,000 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. SPPC also provides natural gas service in Nevada to approximately 146,000 customers in an area of about 600 square miles in the Reno and Sparks areas. The consolidated financial statements of SPPC 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 was 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 accounted for its joint venture interest under the equity method. In December 2006, TGPC sold its partnership interest in the joint venture; see Note 4, Investment in Subsidiaries and Other Property. SPC was formed in 1999 to provide telecommunications services using fiber optic cable technology in both northern and southern Nevada.

Reclassifications

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

Regulatory Accounting and Other Regulatory Assets

The Utilities' rates are currently subject to the approval of the Public Utilities Commission of Nevada (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 deferral 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) regulated rates are designed to recover the specific cost of the regulated products or services; and (iii) it is reasonable to assume that rates are set at levels that recovered costs can be charged to and collected from customers. Management periodically assesses whether the requirements for application of SFAS No. 71 are satisfied.

In addition to the deferral of energy costs discussed below, items to which SPR and the Utilities apply regulatory accounting are included in the tables below.

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates collected from customers. If at any time the incurred costs no longer meet these criteria, these costs are charged to earnings. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections, except for cost of removal which represents the cost of removing future electric and gas assets. Management regularly assesses whether the regulatory assets are probable of future recovery by considering actions of regulators, current laws related to regulation, applicable regulatory environment changes and the status of any current and 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 could 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.

SIERRA PACIFIC RESOURCES

Other Regulatory Assets and Liabilities

		As of December 31, 2006				
		Receiving Regulatory Treatment				
DESCRIPTION	Remaining Amortization Period	Earning a Return[1]	Not Earning a Return	Pending Regulatory Treatment	**2006 Total**	As of December 31, 2005 Total
(dollars in thousands)						
Regulatory Assets						
Loss on reacquired debt	Term of related debt	$ 87,154	$ —	$ —	**$ 87,154**	$ 57,804
Lenzie		—	—	52,456	**52,456**	—
Mohave plant and deferred costs	2026	21,582	—	(3,747)	**17,835**	28,280
Clark Units 1-3	Various thru 2015	11,545	—	5,190	**16,735**	13,136
Piñon Pine	Various thru 2029	35,236	6,155	610	**42,001**	43,502
Plant assets	Various thru 2031	2,876	—	—	**2,876**	3,058
Asset retirement obligations		—	—	16,112	**16,112**	14,904
Nevada divestiture costs	2012	23,983	—	—	**23,983**	28,497
Merger transition/transaction costs	2016	—	28,916	—	**28,916**	32,569
Merger severance/relocation	2016	—	15,884	—	**15,884**	17,951
Merger goodwill	2046	—	293,199	—	**293,199**	281,739
California restructure costs	Thru 2009	979	880	—	**1,859**	2,459
Conservation programs	Thru 2012	2,574	—	50,701	**53,275**	24,144
Legal costs		—	—	8,376	**8,376**	9,558
Other costs	Thru 2017	1,708	2,363	3,892	**7,963**	10,544
Subtotal		$187,637	$347,397	$133,590	**$668,624**	$568,145
Pensions—SFAS 158		—	—	$224,107	**$224,107**	—
Total Regulatory Assets		$187,637	$347,397	$357,697	**$892,731**	$568,145
Regulatory Liabilities						
Cost of removal	Various	$283,641	$ —	$ —	**$283,641**	$246,960
Gain on property sales	Various thru 2008	4,531	—	—	**4,531**	11,285
SO2 allowances	Various thru 2012	745	—	—	**745**	536
Gas transportation contract		—	—	—	**—**	17,542
Plant liability	2008	1,038	—	—	**1,038**	2,049
Impact charge	2008	2,722	—	—	**2,722**	6,066
Depreciation—customer advances		—	—	8,775	**8,775**	—
Other	2008	—	326	125	**451**	—
Total Regulatory Liabilities		$292,677	$ 326	$ 8,900	**$301,903**	$284,438

NEVADA POWER COMPANY

Other Regulatory Assets and Liabilities

DESCRIPTION	Remaining Amortization Period	As of December 31, 2006				As of December 31, 2005 Total
		Receiving Regulatory Treatment		Pending Regulatory Treatment	**2006 Total**	
		Earning a Return[1]	Not Earning a Return			
(dollars in thousands)						
Regulatory Assets						
Loss on reacquired debt	Term of related debt	$ 60,026	$ —	$ —	**$ 60,026**	$ 39,392
Lenzie		—	—	52,456	**52,456**	—
Mohave plant and deferred costs	2026	21,582	—	(3,747)	**17,835**	28,280
Clark Units 1-3	Various thru 2015	11,545	—	5,190	**16,735**	13,136
Asset retirement obligations		—	—	11,081	**11,081**	10,204
Nevada divestiture costs	2012	14,665	—	—	**14,665**	17,459
Merger transition/transaction costs	2014	—	20,237	—	**20,237**	22,838
Merger severance/relocation	2014	—	7,397	—	**7,397**	8,417
Merger goodwill	2044	—	184,386	—	**184,386**	189,088
Conservation programs		—	—	42,636	**42,636**	19,048
Legal costs		—	—	8,376	**8,376**	9,558
Other costs	2008	649	—	3,890	**4,539**	5,147
Subtotal		$108,467	$212,020	$119,882	**$440,369**	$362,567
Pensions—SFAS 158		—	—	$113,646	**$113,646**	—
Total Regulatory Assets		$108,467	$212,020	$233,528	**$554,015**	$362,567
Regulatory Liabilities						
Cost of removal	Various	$162,196	$ —	$ —	**$162,196**	$144,164
Gain on property sales	Various thru 2008	4,531	—	—	**4,531**	11,285
SO2 allowances	Various thru 2012	745	—	—	**745**	536
Gas transportation contract		—	—	—	**—**	17,542
Depreciation—customer advances		—	—	3,701	**3,701**	—
Other		—	—	125	**125**	—
Total Regulatory Liabilities		$167,472	$ —	$ 3,826	**$171,298**	$173,527

SIERRA PACIFIC POWER COMPANY

Other Regulatory Assets and Liabilities

	As of December 31, 2006				
		Receiving Regulatory Treatment			
DESCRIPTION	Remaining Amortization Period	Earning a Return[1]	Not Earning a Return	Pending Regulatory Treatment	**2006 Total**	As of December 31, 2005 Total
(dollars in thousands)						
Regulatory Assets						
Loss on reacquired debt	Term of related debt	$ 27,128	$ —	$ —	**$ 27,128**	$ 18,412
Piñon Pine	Various thru 2029	35,236	6,155	610	**42,001**	43,502
Plant assets	Various thru 2031	2,876	—	—	**2,876**	3,058
Asset retirement obligations		—	—	5,031	**5,031**	4,700
Nevada divestiture costs	2012	9,318	—	—	**9,318**	11,038
Merger transition/transaction costs	2016	—	8,679	—	**8,679**	9,731
Merger severance/relocation	2016	—	8,487	—	**8,487**	9,534
Merger goodwill	2046	—	108,813	—	**108,813**	92,651
California restructure costs	Thru 2009	979	880	—	**1,859**	2,459
Conservation programs	Thru 2012	2,574	—	8,065	**10,639**	5,096
Other costs	Various thru 2017	1,059	2,363	2	**3,424**	5,397
Subtotal		$ 79,170	$135,377	$ 13,708	**$ 228,255**	$205,578
Pensions—SFAS 158		—	—	$106,666	**$ 106,666**	—
Total Regulatory Assets		$ 79,170	$135,377	$120,374	**$ 334,921**	$205,578
Regulatory Liabilities						
Cost of removal	Various	$121,445	$ —	$ —	**$ 121,445**	$102,796
Plant liability	2008	1,038	—	—	**1,038**	2,049
Impact charge	2008	2,722	—	—	**2,722**	6,066
Depreciation—customer advances		—	—	5,074	**5,074**	—
Other	2008	—	326	—	**326**	—
Total Regulatory Liabilities		$125,205	$ 326	$ 5,074	**$ 130,605**	$110,911

(1) Earning a return includes either a carrying charge on the asset/liability balance, or a return as a component of weighted cost of capital.

Deferral of Energy Costs

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

In January 2000, in accordance with a PUCN order, SPPC resumed using deferred energy accounting for its gas operations.

In April 2001, the Governor of Nevada signed into law AB 369. The provisions of AB 369 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 in March 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.

Pursuant to AB 369, Nevada Revised Statute (NRS) 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, NRS 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 following deferred energy costs were included in the consolidated balance sheets as of the dates shown (dollars in thousands):

DESCRIPTION		December 31, 2006 NPC Electric	SPPC Electric	SPPC Gas	SPR Total
Unamortized balances approved for collection in current rates					
Electric—NPC Period 1	(Reinstatement of deferred energy)[1]	**$178,825**	**$ —**	**$ —**	**$178,825**
Electric—NPC Period 3	(effective 4/05, 2 years)	**(4,067)**	**—**	**—**	**(4,067)**
Electric—SPPC Period 3	(effective 6/05, 27 months)	**—**	**6,034**	**—**	**6,034**
Electric—NPC Period 4	(effective 4/05, 2 years)	**6,347**	**—**	**—**	**6,347**
Electric—NPC Period 5	(effective 8/06, 2 years)	**153,720**	**—**	**—**	**153,720**
Electric—SPPC Period 5	(effective 7/06, 2 years)	**—**	**27,657**	**—**	**27,657**
Nat. Gas—Per 6, LPG—Per 5	(effective 12/06, 1 year)	**—**	**—**	**902**	**902**
Balances pending PUCN approval		**72,280**	**16,220**	**—**	**88,500**
Cumulative CPUC balance		**—**	**9,956**	**—**	**9,956**
Balances accrued since end of periods submitted for PUCN approval		**1,693**	**(14,479)**	**(1,014)**	**(13,800)**
Claims for terminated supply contracts[2]		**80,095**	**16,265**	**—**	**96,360**
Total		**$488,893**	**$ 61,653**	**$ (112)[3]**	**$550,434**
Current Assets					
Deferred energy costs—electric		**$129,304**	**$ 38,956**	**$ —**	**$168,260**
Deferred Assets					
Deferred energy costs—electric		**359,589**	**22,697**	**—**	**382,286**
Current Liabilities					
Deferred energy costs—gas		**—**	**—**	**(112)**	**(112)**
Total		**$488,893**	**$ 61,653**	**$ (112)**	**$550,434**

DESCRIPTION		December 31, 2005 NPC Electric	SPPC Electric	SPPC Gas	SPR Total
Unamortized balances approved for collection in current rates					
Electric—NPC Period 2	(effective 5/03, 3 years)	$ (1,199)	$ —	$ —	$ (1,199)
Electric—NPC Period 3	(effective 4/05, 2 years)	48,564	—	—	48,564
Electric—SPPC Period 3	(effective 6/05, 27 months)	—	23,208	—	23,208
Electric—NPC Period 4	(effective 4/05, 2 years)	71,490	—	—	71,490
Electric—SPPC Period 4	(effective 6/05, 1 years)	—	9,101	—	9,101
Natural Gas—Period 5	(effective 11/05, 1 year)	—	—	4,454	4,454
LPG Gas Period 3	(effective 11/04, 2 years)	—	—	36	36
LPG Gas Period 4	(effective 11/05, 1 year)	—	—	130	130
Balances pending PUCN approval		171,447	41,180	—	212,627
Cumulative CPUC balance		—	6,699	—	6,699
Balances accrued since end of period submitted for PUCN approval		26,647	6,768	2,050	35,465
Claims for terminated supply contracts[2]		83,993	21,111	—	105,104
Total		$ 400,942	$108,067	$ 6,670	$ 515,679
Current Assets					
Deferred energy costs—electric		$ 186,355	$ 67,342	$ —	$ 253,697
Deferred energy costs—gas		—	—	5,825	5,825
Deferred Assets					
Deferred energy costs—electric		214,587	40,725	—	255,312
Deferred energy costs—gas		—	—	845	845
Total		$ 400,942	$108,067	$ 6,670	$ 515,679

(1) Amount not in current rates. As discussed in Note 13, Commitments and Contingencies, Nevada Power Company 2001 Deferred Energy Case.

(2) Amounts related to claims for terminated supply contracts are discussed in Note 13, Commitments and Contingencies.

(3) 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.

Carrying Charge on the Lenzie Generating Station

In 2004, the Public Utility Commission of Nevada (PUCN) granted NPC's request to designate the Chuck Lenzie Generating Station ("Lenzie") as a critical facility and allowed a 2% enhanced Return on Equity (ROE) to be applied to the Lenzie construction costs expended after acquisition. The order allowed for an additional 1% enhanced ROE if the two Lenzie generating units were brought on line early. In addition, the PUCN granted NPC's request to begin accumulating a carrying charge as a regulatory asset including the 3% enhanced ROE (collectively referred to as "carrying charges"), until the plant is included in rates.

Units 1 and 2 were declared commercially operable in January 2006 and April 2006, respectively, qualifying for the incentive ROE treatment. Based on the regulatory order, through December 31, 2006, NPC has accumulated approximately $38.9 million in carrying charges; however, $5.5 million of this amount has not been recorded for financial reporting purposes as it represents equity carrying costs that are not recognized until collected through regulated rates. For financial reporting purposes, through December 31, 2006, NPC recognized $33.4 million in other income, and recorded a corresponding regulatory asset, which represents only the carrying charge component associated with incurred debt costs. NPC has requested recovery of the $38.9 million in carrying charges its 2006 General Rate Case filed in November 2006.

Utility Plant

The cost of additions, including betterments and replacements of units of property, are charged to utility plant. When units of property are replaced, renewed or retired, their cost plus removal or disposal costs, less salvage proceeds, are charged to accumulated depreciation. The cost of current repairs and minor replacements are charged to maintenance expense when incurred, with the exception of long-term service agreements. These agreements may have annual payment amounts for repairs which could vary over the life of the agreement between maintenance expense and amounts to be capitalized. To ensure consistency in annual expense for rate-making purposes, the amounts to be charged to maintenance expense are smoothed over the life of the contract, with an offset to a regulatory asset account. Amounts prepaid for capital expenditure are recorded in a prepaid asset account.

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

Allowance for Funds Used During Construction

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, however, 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 rate used during 2006, 2005 and 2004 was 9.03%. SPPC's AFUDC rates used during 2006, 2005 and 2004 were 8.97%, 8.96% and 9.26%, respectively. As specified by the PUCN, certain projects may be assigned a lower or higher AFUDC rate due to specific 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. Depreciation expense 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 2006, 2005 and 2004, as authorized by the PUCN and stated as a percentage of the average depreciable property balances for those years, was approximately 3.15%, 3.15% and 3.05%, respectively. SPPC's depreciation provision for 2006, 2005 and 2004, as authorized by the PUCN and stated as a percentage of the average cost of depreciable property, was approximately 3.08%, 3.3% and 3.35%, respectively.

Impairment of Long-Lived Assets

SPR, NPC and SPPC evaluate on an ongoing basis the recoverability of its assets for impairments whenever events or changes in circumstance indicate that the carrying amount may not be recoverable as described in SFAS No. 144, "Accounting for the Disposal or Impairment of Long-Lived Assets," (SFAS 144). See Note 17, Discontinued Operations and Disposal and Impairment of Long-Lived Assets.

Accounting For Goodwill

SFAS No. 142, "Goodwill and Other Intangible Assets," adopted by SPR, NPC and SPPC in January 2002, changed the accounting for goodwill from an amortization method to one requiring at least an annual review for impairment. See Note 18, Goodwill and Other Merger Costs, for further discussion.

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.

Restricted Cash

At December 31, 2005, SPR had approximately $67.2 million of restricted cash in SPR's consolidated balance sheets, primarily consisting of an aggregate $49 million and $11 million in cash collateral deposited by NPC and SPPC, respectively, into escrow in connection with the stay of the Enron judgment, as described in Note 13, Commitments and Contingencies. The cash collateral plus interest was returned to the Utilities in January 2006.

Federal Income Taxes

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. 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 basis 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.

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

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. Accounts receivable as of December 31, 2006 include unbilled receivables of $92 million and $83 million for NPC and SPPC, respectively. Accounts receivable as of December 31, 2005 include unbilled receivables of $80 million and $77 million for NPC and SPPC, respectively.

Asset Retirement Obligations

SFAS No. 143, "Accounting for Asset Retirement Obligations," provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the standard, these liabilities are 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 is classified as 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. SPR, NPC and SPPC adopted SFAS No. 143 in January 2003.

Management's methodology to assess its legal obligation included an inventory of assets by company, system and components and a review of rights of way and easements, regulatory orders, leases and federal, state and local environmental laws. Management 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. Provisions of the lease require the lessees to remove the facilities upon request of the Navajo Nation at the expiration of the leases.

In March 2005, the Financial Accounting Standards Board (FASB) issued Interpretation No. 47 as clarification to SFAS No. 143. This Interpretation was effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005 for calendar-year enterprises). The Interpretation clarified the term conditional retirement obligation as used in SFAS No. 143 as well as when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

Similar to the methodology used to assess legal obligations under SFAS 143, management reviewed the inventory of assets by system and components, as well as rights of way and easements, regulatory orders, leases, and federal, state and local environmental laws. Management has determined evaporative ponds, dry ash landfills, fuel storage tanks, asbestos and oils treated with Polychlorinated Biphenyl to have met the conditional asset retirement obligations of FIN 47.

As such, included in NPC's and SPPC's Other Liabilities accounts as of December 31, 2006 are approximately $12.9 million and $5.3 million of AROs. As of December 31, 2005, the amounts were approximately $12.1 million and $5.0 million. As the Utilities are subject to SFAS 71 accounting treatment, the cumulative effect of these AROs were recorded in Other Regulatory Assets.

Cost of Removal

In addition to the legal asset retirement obligations booked under SFAS 143 and FIN 47, the Utilities have accrued for the cost of removing non-legal retirement obligations of other electric and gas assets, in accordance with accepted accounting practices. The amounts of such accruals included in regulatory liabilities in 2006 are approximately $162 million and $121 million for NPC and SPPC, respectively. In 2005, the amounts were approximately $144 million and $103 million.

Variable Interest Entities

In December 2003, the FASB issued a revised Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46 (R)), which elaborates on Accounting Research Bulletin No. 51, "Consolidated Financial Statements." Among other requirements, FIN 46 (R) provides that a variable interest entity be consolidated by the enterprise that is the primary beneficiary of the variable interest entity. As of December 2003, SPR, NPC and SPPC adopted FIN 46 (R) for special purpose entities. As of March 2004, SPR, NPC and SPPC adopted FIN 46 (R) for all variable interest entities. To identify potential variable interests, management reviewed long-term purchase power contracts, including contracts with qualifying facilities (QFs), jointly-owned facilities and partnerships that are not consolidated. The Utilities identified seven QFs with long-term purchase power contracts that are variable interests. However, the Utilities are not required at this time to consolidate these QFs under the scope exception provided for in FIN 46 (R) due to the inability to obtain information necessary to (1) determine whether the

entity is a variable interest entity, (2) determine whether the enterprise is the variable interest entity's primary beneficiary, or (3) perform the accounting required to consolidate the variable interest entity for which it is determined to be the primary beneficiary. The Utilities have requested financial information from these QFs but have not been successful in obtaining the information. The Utilities' maximum exposure to loss is limited to the cost of replacing these purchase power contracts if the QFs are unable to deliver power. However, the Utilities believe their exposure is mitigated as they would likely recover these costs through their deferred energy accounting mechanism. The Utilities have not identified any other significant variable interests that require consolidation as of December 31, 2006.

Recent Pronouncements

SFAS 123 (R) SPR adopted Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), "Share-Based Payment" (SFAS 123R), in the first quarter of 2006 using the modified prospective method. The Company had previously applied the provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," in accounting for its stock compensation plans and in accordance with the disclosure only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," and the updated disclosure requirements set forth in SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure." Accordingly, no compensation cost had been recognized previously.

SPR's executive long-term incentive plan for key management employees 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 currently issues Performance Shares and Nonqualified Stock Options (NQSO) under this plan. In addition, the Company also has an Employee Stock Purchase Plan (ESPP). Please refer to Note 12, Stock Compensation Plans, in the Notes to Consolidated Financial Statements for additional information.

The adoption of SFAS 123 (R) did not have a material impact on the results of operations for SPR.

SFAS 157 In September 2006, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 157, "Fair Value Measurement," (SFAS 157). SFAS 157 addresses the need for increased consistency in fair value measurements, defining fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It also establishes a framework for measuring fair value and expands disclosure requirements. SFAS 157 is effective for SPR and the Utilities beginning January 2008. SPR and the Utilities are currently evaluating the impact of the adoption of SFAS 157 on their consolidated financial statements.

SFAS 158 In September 2006, the FASB issued SFAS 158 ("SFAS 158") "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106 and 132-(R)." SFAS 158 requires SPR and the Utilities to recognize the overfunded or underfunded status of defined benefit postretirement plans in their Consolidated Balance Sheets. An overfunded status would result in the recognition of an asset and an underfunded status would result in the recognition of a liability. The adjustment to record an asset or liability would result in a charge or credit to Accumulated Other Comprehensive Income (AOCI), net of income tax effects. SFAS 158's requirement to recognize the funded status of a benefit plan and new disclosure requirements are effective as of the end of the fiscal year ending after December 15, 2006. The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. SPR and the Utilities have recorded amounts that otherwise would be charged/credited to AOCI upon application of SFAS 158 as Other Regulatory Asset/Liabilities as they believe these amounts will be recovered through rates similar to expenses related to SFAS 87, "Employers' Accounting for Pensions," and SFAS 106, "Employers' Accounting for Other Postretirement Expense other than Pensions." At December 31, 2006, SPR, NPC and SPPC recorded $224.1 million, $113.6 million and $106.7 million, respectively in Other Regulatory Assets.

The following tables provide details of the effects of implementing SFAS Statement No. 158 (dollars in thousands):

Pension
Incremental effect of adopting SFAS No. 158 as of December 31, 2006

	Before Adoption	Adjustments to Adopt SFAS 158	Regulatory Accounting Adjustments	Balance after Adoption
ASSETS				
Non-current benefit asset	$ 55,921	$ (55,921)	$ —	$ —
Regulatory asset	$ —	$ —	$ 114,261	$ 114,261
LIABILITIES				
Current benefit liability	$ —	$ (1,482)	$ —	$ (1,482)
Non-current benefit liability	$ (9,809)	$ (99,454)	$ —	$(109,263)
SHAREHOLDERS' EQUITY				
Accumulated other comprehensive (income) loss	$(46,112)	$156,857	$(114,261)	$ (3,516)

Other Benefits
Incremental effect of adopting SFAS No. 158 as of December 31, 2006

	Before Adoption	Adjustments to Adopt SFAS 158	Regulatory Accounting Adjustments	Balance after Adoption
ASSETS				
Non-current benefit asset	$ 10,182	$ (10,182)	$ —	$ —
Regulatory asset	$ —	$ —	$ 108,956	$ 108,956
LIABILITIES				
Non-current benefit liability	$(52,778)	$ (56,178)	$ —	$(108,956)
SHAREHOLDERS' EQUITY				
Accumulated other comprehensive (income) loss	$ 42,596	$ 66,360	$(108,956)	$ —

At December 31, 2006, SPR, NPC and SPPC recorded pension liabilities of $110.7 million, $66.1 million and $34.9 million, respectively, as a result of the adoption of SFAS No. 158. In addition, SPR, NPC and SPPC also recorded liabilities of $109.0 million, $21.5 million and $87.9 million, respectively, for the other postretirement benefit plan as a result of the adoption of SFAS No. 158. At December 31, 2005, SPR, NPC and SPPC had pension liabilities of $16.4 million, $4.0 million and $5.8 million, respectively, and additional minimum liabilities of $7.9 million, $4.4 million and $2.8 million, respectively, under the provisions of SFAS No. 87 for the pension plan. SPR, NPC and SPPC had liabilities of $36.3 million, $14.1 million and $31.7 million, respectively, at December 31, 2005 for the other postretirement benefit plan.

FIN 46(R)-6 In April 2006, the FASB issued FASB Staff Position ("FSP") FIN 46R-6, *Determining the Variability to Be Considered in Applying FASB Interpretation No. 46(R)*. This FSP addresses certain implementation issues related to FASB Interpretation No. 46 (Revised December 2003), *Consolidation of Variable Interest Entities*. Specifically, FSP FIN 46R-6 addresses how a reporting enterprise should determine the variability to be considered in applying FIN 46R. The variability that is considered in applying FIN 46R affects the determination of (a) whether an entity is a variable interest entity ("VIE"), (b) which interests are "variable interests" in the entity, and (c) which party, if any, is the primary beneficiary of the VIE. That variability affects any calculation of expected losses and expected residual returns, if such a calculation is necessary. SPR and the Utilities are required to apply the guidance in this FSP prospectively to all entities (including newly created entities) and to all entities previously required to be analyzed under FIN 46R when a "reconsideration event" has occurred, beginning July 2006. SPR and the Utilities will evaluate the impact of this Staff Position at the time any such "reconsideration event" occurs, and for any new entities.

FIN 48 In July 2006, the FASB issued FASB Interpretation No. 48 ("FIN 48") "Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109," to clarify certain aspects of accounting for uncertain tax positions, including issues related to the recognition and measurement of those tax positions. This interpretation is effective for fiscal years beginning after December 15, 2006. SPR and the Utilities are in the process of evaluating the impact FIN 48 will have on their consolidated financial statements.

SAB 108 In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," (SAB 108), to address diversity in practice in quantifying financial statement misstatements. SAB 108 requires that SPR and the Utilities quantify misstatements based on their impact on each of its financial statements and related disclosures. SAB 108 is effective as of December 31, 2006, allowing a one-time transitional cumulative effect adjustment to retained earnings as of January 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108. The adoption of SAB 108 did not have an effect on the consolidated financial statements of SPR or the Utilities.

NOTE 2. SEGMENT INFORMATION

SPR's Utilities operate three business segments (as defined by SFAS 131, "Disclosure about Segments of an Enterprise and Related Information"), which are NPC electric, SPPC electric and SPPC natural gas service. Electric service is provided to Las Vegas and surrounding Clark County by NPC, northern Nevada and the Lake Tahoe area of California by SPPC. Natural gas services are provided by SPPC in the Reno-Sparks area of Nevada. Other segment information includes segments below the quantitative threshold for separate disclosure.

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 (dollars in thousands).

December 31, 2006	**NPC Electric**	**SPPC Electric**	**Total Electric**	**Gas**	**All Other**	**Reconciling Eliminations**	**Consolidated**
Operating revenues	**$2,124,081**	**$ 1,020,162**	**$3,144,243**	**$ 210,068**	**$ 1,639**	**—**	**$3,355,950**
Operating income	**351,272**	**108,908**	**460,180**	**11,109**	**17,508**	**—**	**488,797**
Operating income taxes	**91,781**	**20,020**	**111,801**	**3,550**	**(23,780)**	**—**	**91,571**
Depreciation	**141,585**	**79,580**	**221,165**	**7,699**	**11**	**—**	**228,875**
Interest expense on long-term debt	**171,188**	**66,416**	**237,604**	**5,453**	**51,431**	**—**	**294,488**
Assets	**5,987,515**	**2,476,483**	**8,463,998**	**275,294**	**36,724**	**56,060**	**8,832,076**
Capital expenditures	**670,441**	**282,641**	**953,082**	**32,937**	**—**	**—**	**986,019**

December 31, 2005	NPC Electric	SPPC Electric	Total Electric	Gas	All Other	Reconciling Eliminations	Consolidated
Operating revenues	$1,883,267	$ 967,427	$ 2,850,694	$ 178,270	$ 1,278	—	$3,030,242
Operating income	228,827	107,213	336,040	9,091	13,547	—	358,678
Operating income taxes	46,425	24,209	70,634	1,829	(33,278)	—	39,185
Depreciation	124,098	82,676	206,774	7,893	(5)	—	214,662
Interest expense on long-term debt	159,106	63,040	222,146	6,200	74,322	—	302,668
Assets	5,173,921	2,218,938	7,392,859	245,707	150,324	81,656	7,870,546
Capital expenditures	546,748	121,767	668,515	17,879	—	—	686,394

December 31, 2004	NPC Electric	SPPC Electric	Total Electric	Gas	All Other	Reconciling Eliminations	Consolidated
Operating revenues	$1,784,092	$ 881,908	$2,666,000	$153,752	$ 5,044	—	$2,824,796
Operating income	216,490	103,513	320,003	7,732	6,123	—	333,858
Operating income taxes	45,135	12,740	57,875	2,238	(37,374)	—	22,739
Depreciation	118,841	79,298	198,139	7,508	275	—	205,922
Interest expense on long-term debt	152,764	64,729	217,493	6,583	89,229	—	313,305
Assets	4,883,540	2,226,949	7,110,489	232,092	120,607	65,279	7,528,467
Capital expenditures	482,484	117,329	599,813	14,598	—	—	614,411

The reconciliation of segment assets at December 31, 2006, 2005 and 2004 to the consolidated total includes the following unallocated amounts:

	2006	2005	2004
Cash	**$53,260**	$53,024	$35,783
Other regulatory assets	**—**	19,265	21,124
Deferred charges—other	**2,800**	9,367	8,372
	$56,060	$81,656	$65,279

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 (IRPs) to the PUCN for approval.

Under federal law, the Utilities 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, 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 Department of Air Quality and Environmental Management (DAQEM) administer regulations involving air quality, water pollution, solid, hazardous and toxic waste. SPR's Board of Directors has a comprehensive environmental policy and separate board committee that oversees NPC, SPPC and SPR's corporate performance and achievements related to the environment.

Deferred Energy Accounting

The Utilities began using deferred energy accounting for their respective electric operations in March 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

2006 GENERAL RATE CASE In November 2006, NPC filed its statutorily required electric General Rate Case. This filing requested authorization to:

- Increase annual general revenues by $172.4 million which is approximately an 8% increase
- Set the Return on Equity and Rate of Return at 11.40% and 9.41%, respectively
- Recover 100% of the amortization of the 1999 NPC/SPPC merger costs rather than the 80% recovery that is currently in general rates
- Implement the PUCN's previous orders regarding incentive ratemaking for the Chuck Lenzie Generating Station
- Implement new depreciation rates

Hearings are scheduled to take place in late March and early April of 2007 with rates expected to be effective on or before June 1, 2007.

In February 2007, NPC submitted its certification filing which lowered the requested ROR to 9.39% and the general revenues increase was lowered to $156.4 million, representing an overall rate increase of 7.4%.

2007 DEFERRED ENERGY RATE CASE AND BTER UPDATE In January 2007, NPC filed an electric DEAA Rate Case and BTER Update application with the PUCN. The application seeks recovery of $75 million of deferred fuel and purchased power costs and requested to reset NPC's going forward BTER to reflect anticipated changes in future energy costs. This application requests a 1.6% decrease in overall rates.

2007 WESTERN ENERGY CRISIS RATE CASE In January 2007, NPC filed an application to recover $83.6 million over four years in deferred legal and settlement costs incurred to resolve claims associated with power supply contracts terminated during the Western Energy Crisis. This application requests an overall rate increase of less than 1%.

In February 2007, NPC entered into a stipulation, with the parties to the case, to recover the $83.6 million plus carrying charges over a 3-year period beginning June 1, 2007. This stipulation is expressly conditioned upon the PUCN's acceptance of the concurrently filed stipulation related to NPC's 2001 Deferred Energy Case, discussed below. If the PUCN does not accept both stipulations, this stipulation shall be deemed withdrawn, and all parties will retain all rights to litigate. The PUCN has yet to issue an order on the stipulation.

2006 DEFERRED ENERGY RATE CASE AND BTER UPDATE In January 2006, NPC filed a DEAA Rate Case with the PUCN seeking recovery of deferred fuel and purchased power costs accumulated between October 1, 2004 and November 30, 2005, and to increase its going forward Base Tariff Energy Rate (BTER) to reflect anticipated changes in future energy costs. NPC requested a one-year amortization period to recover the deferred balance.

NPC requested that the BTER increase become effective on May 1, 2006. The BTER change represented an 8% increase for the average customer and is expected to generate $138 million of new revenues for fuel and power purchases.

NPC requested authorization to begin a one-year recovery of the $171.5 million deferred balance in August 2006. The requested DEAA adjustment represents an additional rate increase of approximately 9.3%.

In April 2006, the PUCN approved an agreement among the interveners and NPC, which, effective May 1, 2006, set NPC's BTER rates such that an estimated $112 million (revised by June 2006 DEAA agreement—see below) of new revenues would be collected for fuel and power purchases in addition to the start of an $8.4 million collection related to a previous DEAA Rate Case. Combined, the approximately $120 million increase represented an overall average rate increase of approximately 6.5%.

In the Deferred Energy portion of the case, NPC had requested authorization to recover $171.5 million of previously incurred purchased fuel and power costs over a one-year period. In June 2006, the PUCN approved a negotiated settlement, which specified (1) a reduction of $1.6 million to the BTER approved in April 2006 based on an updated projection of costs and (2) granted NPC full recovery of the $171.5 million of deferred costs during a two-year period beginning August 2006. However, the $171.5 million was reduced by a $16.5 million payment previously received by NPC in connection with the Lenzie acquisition. Under this agreement, the DEAA rate changes required to asymmetrically recover the deferred balance are scheduled to be implemented during a two-year period such that they will be offset by the expiration of previously approved DEAA rates. As a result, no rate increase was required.

2005 BTER UPDATE In June 2005, NPC filed a request to increase its BTER to reflect forecasted energy costs. NPC expected the request would increase revenue by $66.9 million for the 12-month period October 1, 2005 to September 30, 2006 and more closely correlate fuel and purchased power revenues with fuel and purchased power costs. In September 2005, the PUCN issued an order approving the BTER rate changes requested in NPC's filing.

2004 DEFERRED ENERGY RATE CASE In November 2004, NPC filed an application with the PUCN seeking recovery of deferred fuel and purchased power costs accumulated between October 1, 2003 and September 30, 2004. The application sought to establish a rate to collect accumulated fuel and purchased power costs of $116 million, with a carrying charge. The application requested that the 2004 DEAA recovery begin with the expiration of the 2002 DEAA recovery, which was expected to occur in May 2006 and for the 2004 DEAA recovery period to be 22 months.

The application also requested an increase to NPC's BTER.

In concert with this 2004 DEAA filing, NPC filed a petition with the PUCN requesting that other pending DEAA rate changes be synchronized to change in April 2005 in order to stabilize rates and reduce the number of rate changes. In December 2004, the PUCN issued an order approving a stipulation reached by all parties that allows NPC to defer previously approved DEAA rate changes until April 2005 coincident with the DEAA rate change that will result from the 2004 DEAA case.

The combined effect of the requested synchronization of multiple rate changes (going forward BTER increase, 2001 DEAA expiration and 2003 DEAA initiation) resulted in a request for an overall rate decrease of 2.4%.

In February 2005, a stipulation of the parties was filed with the PUCN resolving all issues in the case. The stipulation provided for an overall decrease of 0.6% in total rates with no disallowances. The PUCN approved the stipulation in total in March 2005.

2003 DEFERRED ENERGY RATE CASE In November 2003, NPC filed an application with the PUCN seeking recovery of deferred fuel and purchased power costs accumulated between October 1, 2002 and September 30, 2003, as required by law. The application sought to establish a rate to collect accumulated fuel and purchased power costs of $93 million. In March 2004, the PUCN granted approval for NPC to increase its going forward energy rate as filed, approved recovery for $89 million of its deferred balance, denied $4 million and denied NPC's request for a tax gross-up on the equity portion of carrying charges. Of the $4 million disallowed, $1.6 million was charged to income in the current period as the remaining amount had no impact on earnings or was charged to income in prior periods. The PUCN ordered the change in going forward rates to take effect April 2004 and delayed the implementation of the deferred energy balance recovery until January 2005 when recovery of the 2001 deferred balance was expected to have been completed.

In December 2004, the PUCN issued an order approving a stipulation reached by all parties that allows NPC to defer the 2003 DEAA rate change until April 2005, which will be coincident with the DEAA rate change that will result from the 2004 DEAA case.

2002 DEFERRED ENERGY RATE CASE In November 2002, NPC filed an application with the PUCN seeking repayment for purchased fuel and power costs accumulated between October 1, 2001 and September 30, 2002, as required by law. The application sought to establish a rate to collect 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 requested a reduction to the going forward rate for energy, reflecting reduced wholesale energy costs. The combined effect of these two adjustments resulted in a request for an overall rate reduction of approximately 6.3%.

The decision on this case was issued in May 2003, and authorized the following:

- recovery of $147.6 million, with a carrying charge, and a $48.1 million disallowance;
- a three-year amortization of the balance commencing on May 19, 2003;
- a reduction in the Base Tariff Energy Rate (BTER) to an effective non-residential rate of $0.04322 per kWh, and an effective residential rate of $0.04186 per kWh.

The new rates went into effect in May 2003.

The BCP filed a Petition that challenged the recovery of all costs with the District Court of Clark County, Nevada, for Judicial Review of the PUCN Order in August 2003, against PUCN, Case No. A471928. In September 2003, the PUCN filed its answer to the BCP Petition. The PUCN response cites a number of affirmative defenses to the allegations contained in the BCP Petition and asks that the court dismiss the BCP Petition. The BCP filed its opening brief in January 2004 and responding briefs were filed in March 2004. The court has not yet ruled on this matter.

2001 DEFERRED ENERGY RATE CASE In November 2001, NPC filed an application with the PUCN seeking repayment 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 rate to repay 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.

In March 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. NPC and the BCP both sought individual review of the PUCN Order in the First District Court of Nevada. The District Court affirmed the PUCN's decision. Both NPC and the BCP filed Notices of Appeal to the Nevada Supreme Court.

In July 2006, the Supreme Court of Nevada ruled NPC is allowed to recover approximately $180 million of the deferred energy costs and directed the District Court to remand the issue back to the PUCN to determine the rate schedule that will be used to recover this amount. In all other respects, the Nevada Supreme Court affirmed the District Court's decision on the PUCN disallowance. In 2006, as a result of the Nevada Supreme Court decision, NPC recorded approximately $180 million, before tax, of the previously deferred energy costs in its Income Statements as "Reinstatement of Deferred Energy." NPC is unable to predict the terms of the rate schedule that the PUCN will provide for recovery of this amount.

In February 2007, NPC entered into a stipulation where NPC shall be authorized to recover in rates $189.9 million over ten years beginning on June 1, 2007, with no additional carrying charges. This stipulation is expressly conditioned upon the PUCN's acceptance of the concurrently filed stipulation related to the Western Energy Crisis, discussed above. If the PUCN does not accept both stipulations, this stipulation shall be deemed withdrawn, and all parties will retain all rights to litigate. The PUCN has yet to issue an order on the stipulation.

Sierra Pacific Power Company

2005 ELECTRIC AND GAS GENERAL RATE CASES In October 2005, SPPC filed a gas General Rate Case along with its statutorily required electric General Rate Case. SPPC's last gas General Rate Case was filed in 1992 and the last electric General Rate Case was filed in 2003. The following items are requested in the filings:

- Electric general revenue increase: $27 million or 3.4% effective May 1, 2006
- Gas general revenue increase: $8.3 million or 5.4%, effective May 1, 2006
- Electric Return on Equity and Rate of Return: 11.4% and 9.27%, respectively
- Gas Return on Equity and Rate of Return: 11.4% and 8.29%, respectively
- Approval to continue to recover an allocated amount of the 1999 NPC/SPPC merger costs from electric customers
- Approval to recover an allocated amount of the 1999 NPC/SPPC merger costs from gas customers
- New depreciation rates for gas and electric facilities

SPPC submitted its certification filing for cost of capital and depreciation rates in December 2005 and its revenue requirements and rate design certification filing in January 2006. These filings did not change the requested ROE, ROR or depreciation rates, but did adjust the requested electric revenue increase to $3.2 million.

In January 2006, the interveners filed direct testimony addressing return on equity, overall rate of return and depreciation rates. The PUCN staff has recommended a 10.28% ROE for electric and gas operations, an 8.97% electric ROR, an 8.06% gas ROR and depreciation rates that would result in decreased depreciation expenses. Other interveners are recommending ROEs ranging from 9.1% to 10.9%, electric RORs from 8.35% to 9.08% and gas RORs from 7.52% to 8.10%. The other interveners have also suggested depreciation rates lower than SPPC's filing.

In February 2006, the interveners filed direct testimony addressing overall revenue requirements, including the effects of their ROE, ROR and depreciation rate recommendations. The PUCN staff recommended a $15 million decrease to current electric revenues and a $3.6 million increase to gas revenues. The Bureau of Consumer Protection (BCP) recommended a $32 million reduction to current electric revenues and

a $0.6 million increase to current gas revenues. The Nevada Resort Association recommended a $12 million decrease to current electric revenues.

In April 2006, the PUCN issued its order to change electric and gas general rates. Although the order differed from SPPC's requested filing, the changes did not require material adjustments to net income for the six months ended June 30, 2006. The PUCN vote resulted in the following significant items:

- Electric general revenue decrease: approximately $14 million annually or 1.5%, effective May 1, 2006
- Gas general revenue increase: $4.5 million annually or 2.3%, effective May 1, 2006
- Electric Return on Equity and Rate of Return: 10.6% and 8.96%, respectively
- Gas Return on Equity and Rate of Return: 10.6% and 7.98%, respectively
- Approval to continue recovery of SPPC's allocated amount of the 1999 NPC/SPPC merger costs and goodwill from electric customers
- Approval to recover an allocated amount of the 1999 NPC/SPPC merger costs and goodwill from gas customers
- New depreciation rates for gas and electric facilities.
- Deferred recovery of legal expenses related to the Enron purchased power contract litigation

2003 ELECTRIC GENERAL RATE CASE SPPC filed its biennial General Rate Case in December 2003, as required by law. SPPC requested an $87 million increase in the annual revenue requirement for general rates. In April 2004, SPPC, the Staff of the PUCN and other interveners in SPPC's 2003 General Rate Case negotiated a settlement agreement that resolved most of the issues in the revenue requirement and cost of capital portions of SPPC's case. The agreement, which has been approved by the PUCN, includes the following provisions:

- SPPC was allowed to recover a $40 million increase in annual rates.
- SPPC was allowed a Return on Equity (ROE) of 10.25% and an overall Rate of Return (ROR) of 9.26%, an improvement over SPPC's previous ROE and ROR, which were 10.17% and 8.61%, respectively. SPPC had sought an ROE of 12.4% and ROR of 10.03%.
- The agreement accepted SPPC's requested accounting treatment as filed in its application for purposes of recording revenues, expenses and assets with the following exception. Accounting issues common to SPPC's General Rate Case and NPC's General Rate Case that was decided by the PUCN in March 2004, in Docket No. 03-10001, are treated as set forth in the PUCN's Order on NPC's General Rate Case, except for merger costs. The accounting treatment for merger costs and goodwill established in the NPC decision will apply to the recovery of these costs by SPPC, except that SPPC will include in rates 100% of the costs as filed until recovery is reset by the PUCN in SPPC's next general rate application.
- Required SPPC to file a set of recommended quality of service and customer service measurements to be used in future General Rate Case proceedings. In July 2004, SPPC and NPC jointly filed with the PUCN their recommended quality of service and customer service measurements.

The parties also reached a stipulated agreement that resolved the rate design issues in the case.

Investments in the Piñon Pine generating facility were not addressed by the stipulation. SPPC had sought recovery of its investment of approximately $96 million ($90 million associated with the Nevada jurisdiction) for costs associated with this facility over an extended period (between 10 and 25 years). The recovery of these costs would be in addition to the $40 million annual increase provided for by the stipulation agreement.

In May 2004, the PUCN issued an Order accepting the two stipulations discussed above, and responding to SPPC's request for recovery of the Piñon investments. The PUCN permitted recovery of approximately $37 million (Nevada jurisdictional) of the costs plus a carrying charge to be amortized over 25 years and approximately $11 million (Nevada jurisdictional) of costs without a carrying charge to be amortized over 10 years. The PUCN Order granted a $46.7 million increase to SPPC's general revenues.

As a result of the PUCN Order, SPPC evaluated the Piñon Pine generating facility for impairment under the provisions of SFAS No. 90, "Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs." As a result of this evaluation, SPPC recognized an impairment loss of approximately $47 million in the second quarter of 2004. The impairment loss recognized consists of disallowed costs of approximately $43 million and an additional $4 million loss because the PUCN did not permit a carrying charge on $11 million of the costs to be recovered.

SPPC filed a petition for judicial review of the PUCN's Piñon Decision in the Second Judicial District Court of Nevada in June 2004. The petition is based on existing resource planning statutes and regulations as they apply to the Piñon project. The Piñon project was approved by the PUCN in SPPC's 1992 Integrated Resource Plan as presented.

In January 2006, the court vacated the PUCN's disallowance in Sierra Pacific's 2003 General Rate Case and remanded the case back to the PUCN for further review whether the costs were justly and reasonably incurred. In March 2006, the PUCN appealed the Order to the Nevada Supreme Court (the "Supreme Court") and filed a motion to stay the Order pending the appeal to the Supreme Court. In June 2006, the District Court granted PUCN's motion to stay the Order. In July 2006, the Supreme Court issued an order questioning the finality of the District Court's decision and thus whether it has jurisdiction over the appeal and invited the parties to brief this matter. The BCP and PUCN responded in early August 2006. The Supreme Court dismissed the appeal in September 2006. Requests for rehearing were denied in late December 2006, and in January 2007 the matter was remitted back to the District Court, which, consistent with its January 2006 order, will remand the matter back to the PUCN for further review. A procedural schedule for this review has not yet been established.

2006 ELECTRIC DEFERRED ENERGY RATE CASE AND BTER UPDATE In December 2006, SPPC filed an electric DEAA Rate Case and BTER Update application with the PUCN. The application seeks recovery of $18.7 million of deferred fuel and purchased power costs and requested to reset SPPC's going forward BTER to reflect anticipated changes in future energy costs. This application requests a 0.86% decrease in overall rates.

2006 WESTERN ENERGY CRISIS RATE CASE In December 2006, SPPC filed an application to recover $22.6 million over four years in deferred legal and settlement costs incurred to resolve claims associated with power supply contracts terminated during the Western Energy Crisis. This application requests an overall rate increase of less than 1%.

In February 2007, SPPC entered into a stipulation where SPPC replaces its request to implement rates on July 1, 2007 with a request to establish a regulatory asset to recover the costs. SPPC further requests authority to recover carrying charges on the regulatory asset. SPPC may request authority to begin recovering the regulatory asset established by the PUCN in a future application to change rates. The parties to the stipulation have requested that the PUCN issue an order by September 30, 2007.

DECEMBER 2005 DEFERRED ENERGY RATE CASES AND BASE TARIFF ENERGY RATE UPDATES In December 2005, SPPC filed an electric Deferred Energy Rate Case application with the PUCN. The application sought to establish a rate to collect accumulated fuel and purchased power costs of $46.7 million from the December 2004 to September 2005 deferral period and $17.5 million from the previously approved unamortized deferrals, for a total $64.2 million. In June 2006, the PUCN approved a negotiated settlement, which granted SPPC full recovery of the deferred costs during a two-year period beginning July 2006. Under this agreement, the DEAA rate changes required to asymmetrically recover the $46.7 million deferred balance are scheduled to be implemented such that they will be offset by the expiration of previously approved DEAA rates. As a result, no rate increase was required

The application also requested an increase to the BTER. In April 2006, the PUCN issued an Order authorizing SPPC to increase its BTER on May 1, 2006, such that SPPC expects to collect $31 million in new revenues for purchased power. The change represented a 3.5% increase to customer rates.

JULY 2005 ELECTRIC BASE TARIFF ENERGY RATE UPDATE In July 2005, SPPC filed a request to increase its BTER to reflect forecasted energy costs. The request was expected to increase revenue by $32.3 million for the period October 1, 2005 to September 30, 2006, and was intended to more closely correlate fuel and purchased power revenues with fuel and purchased power costs.

In October 2005, the PUCN voted to approve a new electric BTER effective November 1, 2005. The new rate represented a 7.3% overall electric rate increase and was expected to produce $64 million additional revenues during the following 12 months.

JANUARY 2005 ELECTRIC DEFERRED ENERGY RATE CASE FILING In January 2005, SPPC filed an application with the PUCN seeking recovery of deferred fuel and purchased power costs accumulated between December 2003 and November 2004, as required by law. The application also requested an increase to the BTER or going forward energy rate.

The PUCN issued its Order in May 2005 granting $27.1 million deferred expense recovery ($27.7 million requested less $0.6 million), modifying the amortization period from the two years requested to one year and approving a BTER rate based on the historical costs methodology as provided for in the Nevada Administrative Code. The overall rate increase was 5.15%.

SPPC 2004 DEFERRED ENERGY CASE In January 2004, SPPC filed an application with the PUCN, as required by law, seeking to clear deferred balances of approximately $42 million for purchased fuel and power costs accumulated between December 1, 2002 and November 30, 2003.

In July 2004, the PUCN ruled on the Deferred Energy Case, and approved a full recovery of the fuel and purchased power costs. The PUCN Order delayed the start of the deferred balance recovery until April 2005, which corresponds with the expected repayment of previous deferred balances. The PUCN also ordered SPPC to implement a higher BTER rate (the rate paid for going forward energy purchases) than that requested by SPPC. The higher BTER rate represents an overall increase of 4.4% in electric rates for SPPC and became effective in July 2004.

2006 NATURAL GAS AND PROPANE DEFERRED ENERGY RATE CASE AND BTER UPDATE In May 2006, SPPC's gas distribution operation filed applications with the PUCN seeking recovery of deferred natural gas and propane costs accumulated between April 1, 2005 and March 31, 2006. The applications sought to establish a new natural gas DEAA rate to recover $2.5 million of deferred natural gas costs and a new propane DEAA rate to recover $120 thousand of deferred propane costs. SPPC also requested authorization to increase going forward natural gas and propane BTER's to reflect forecasted gas costs.

In October 2006, the PUCN approved negotiated natural gas and propane settlements which consolidated the deferred natural gas and propane balances for collection from all gas customers and reduced the combined balance to $1.1 million. The agreements transferred approximately $1.4 million to other deferral periods and $.1 million to expense accounts. The agreements called for the cost recovery to occur over a 12-month period beginning in December 2006.

The negotiated going forward natural gas rate is expected to recover an additional $1.3 million in revenue, which is a decrease from the originally requested $24.5 million. The decrease reflects more current natural gas price expectations.

These settlements, combined with the expiration of a previous natural gas DEAA rate will cause natural gas customer rates to decrease by 2.5% and cause propane customer rates to increase by 3.3%.

2005 GAS DEFERRED ENERGY RATE CASE AND BASE TARIFF ENERGY RATE UPDATE In May 2005, SPPC filed a gas Deferred Energy Rate Case requesting recovery of $6.9 million of deferred energy costs. The filing requested a two-year amortization of the deferred energy balance which represents a 3.2% average increase for all customers.

In July 2005, SPPC filed a proposed gas BTER, which represented an average increase of 19.5% for all customer classes. The estimated BTER revenue would not change SPPC's operating income.

In October 2005, the PUCN voted to approve recovery of $6.9 million of deferred energy costs with a one-year amortization and set a new gas BTER rate, both effective in November 2005. The new BTER was expected to produce $34.1 million additional revenues during a 12- month period. The combined increases represented a 25.3% overall gas rate increase.

SPPC NATURAL GAS DISTRIBUTION 2004 ANNUAL PURCHASED GAS COST ADJUSTMENT In May 2004, SPPC filed its annual application for Purchased Gas Cost Adjustment for its natural gas local distribution company. In the application, SPPC asked for an increase of $0.09456 per therm to its Base Purchased Gas Rate to recover its expected going forward gas costs. SPPC also requested that $0.02857 per therm be added to the Balancing Account Adjustment (BAA) rate to amortize an approximate $3.9 million balance of deferred gas costs, which were accumulated during the accounting period. Combined with the simultaneous expiration of past BAA charges, the new BAA rate would be $0.03869 per therm less than the current BAA rate. Overall, this request would result in a rate increase of approximately 5%.

The parties agreed to a stipulation, which recommended the PUCN approve the requested rates and the PUCN issued an Order approving the rate increase in November 2004.

California Electric Matters (Sierra Pacific Power Company)

2006 ENERGY COST ADJUSTMENT CLAUSE RATE CASE In April 2006, SPPC filed with the CPUC to reset its "balancing" rate to recover a forecasted deferred energy cost balance and to increase its "offset" rate for going forward fuel and power purchases. The requested increase in the balancing rate is expected to result in $1.1 million additional revenue and the requested increase in the offset rate is expected to collect an additional $10.1 million. The total request represents an $11.2 million annual revenue increase or a 16.5% average increase to customer rates.

In October 2006, the CPUC authorized SPPC's request as filed.

2005 GENERAL RATE CASE In June 2005, SPPC filed a California General Rate Case requesting $8.1 million of new revenue from approximately 40,000 California customers. The request represents a 12.7% average increase. SPPC requested that the new rates become effective in January, 2006.

In August 2006, the CPUC approved a settlement agreement, which, beginning in September, 2006, allowed SPPC to collect an estimated $4.1 million of additional general revenues from its California customers.

2004 ENERGY COST ADJUSTMENT CLAUSE RATE CASE In May 2004, SPPC filed its annual Energy Cost Adjustment Clause (ECAC) in California. The filing updated its estimated fuel and purchase power costs for its California customers and sought to recover or refund any deferred amounts projected through September 2004. The filing requests $8.3 million or a 14.8% overall increase consisting of $3.9 million increase in the base rate and $4.4 million for the projected balance. In November 2004, the CPUC approved SPPC's adjusted request and the increase became effective in December 2004.

RATE STABILIZATION PLAN In June 2001, SPPC filed with the CPUC a Rate Stabilization Plan, which included two phases. Phase One, which was also filed in June 2001, was an emergency electric rate increase of $10.2 million annually or 26%. In July 2002, the CPUC approved the requested 2-cent per kilowatt-hour surcharge, subject to refund and interest pending the outcome of Phase Two. Rates went into effect July 2002.

Phase Two of the Rate Stabilization Plan was filed with the CPUC in April 2002, and included a General Rate Case and requested the CPUC to reinstate the ECAC, which would allow SPPC to file for annual rate adjustments to reflect its actual costs for wholesale energy supplies. This request was for an additional overall increase in revenues of 17.1%, or $8.9 million annually.

In January 2004, the CPUC issued Decision No. 04-01-027, which approved a settlement agreement that included an increase of $3.02 million or 5.8%, adopted a rate design methodology and re-instituted the ECAC mechanism. The rate increase was effective January 16, 2004.

FERC Matters

SIERRA PACIFIC POWER COMPANY 2004 TRANSMISSION RATE CASE In October 2004, the Utilities filed with the FERC revised rates for transmission service offered by SPPC under Docket No. ER05-14. The purpose of the filing was to update rates to reflect recent transmission additions and to improve rate design. The participants in the proceeding filed a Settlement Agreement with the FERC, which was certified by the Settlement Judge. In May 2005, the FERC issued an order approving the negotiated settlement.

NEVADA POWER COMPANY 2003 TRANSMISSION RATE CASE In September 2003, the Utilities filed with the FERC revised rates for transmission service offered by NPC under Docket No. ER03-1328. The purpose of the filing was to update rates to reflect recent transmission additions and to improve rate design. In November 2003, FERC accepted the revised tariff sheets, made rates effective in November 2003, subject to refund, and established hearing procedures. The active participants in the proceeding reached a settlement in principle of all issues. The Certification of Uncontested Offer of Settlement was issued in June 2004. The FERC issued an Order approving the uncontested settlement in July 2004. Refunds were issued within thirty days as required by FERC.

NEVADA POWER COMPANY Based on the FERC's orders to date, NPC believes the recalculated energy prices for NPC sales to the California Independent System Operator (CAISO) and the bankrupt California Power Exchange (CALPX) would result in an approximate $19 million refund. The FERC has also allowed for energy sellers to provide cost justification in the event the recalculated energy prices fall below sellers' costs. NPC's developed and filed a cost-based filing, which justified a $6 million reduction to the estimated refunds resulting in a $13 million refund.

The CAISO and CALPX currently owe NPC approximately $19 million for power delivered during the same time frame and a $13 million refund would reduce the amount owed to Nevada Power to $6 million. NPC previously recorded a reserve against the $19 million receivable in 2001.

SIERRA PACIFIC POWER COMPANY Based on the FERC's orders to date, SPPC believes the recalculated energy prices for sales to the CAISO and CALPX during the October 2, 2000 to June 20, 2001 time frame would result in a $4 million refund.

The CAISO and CALPX currently owe SPPC approximately $1 million for power delivered during the same time frame and SPPC recorded a reserve against the $1 million receivable in 2001. In 2004, SPPC recorded an additional $3 million liability for this item.

NOTE 4. INVESTMENTS IN SUBSIDIARIES AND OTHER PROPERTY

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

Sierra Pacific Resources

December 31,	**2006**	2005
Investment in Tuscarora Gas Transmission Company[1]	**$ 590**	$30,898
Cash value-life insurance	**12,891**	13,281
Non-utility property of NEICO	**5,101**	4,948
NVPCT-I & NVPCT-III	**—**	5,841
Decatur/Gilmore/Cheyenne/Centennial	**4,184**	5,179
Other non-utility property	**11,559**	22,624
	$34,325	$82,771

(1) Tuscarora Gas Pipeline Company (TGPC), which is wholly-owned by SPR, sold its interest in Tuscarora Gas Transmission Company during December 2006 for approximately $100 million. The gain on the sale of the investment was approximately $40.9 million after taxes.

Nevada Power

December 31,	**2006**	2005
Cash value-life insurance	**$12,891**	13,281
Non-utility property of NEICO	**5,101**	4,948
NVPCT-I & NVPCT-III	**—**	5,841
Decatur/Gilmore/Cheyenne/Centennial	**4,184**	5,179
	$22,176	$29,249

Sierra Pacific Power

December 31,	**2006**	2005
Non-utility property	**$609**	$842

NOTE 5. JOINTLY OWNED FACILITIES

At December 31, 2006, NPC and SPPC owned the following undivided interests in jointly owned electric utility facilities:

Joint Facility	% Owned	Plant-in-Service	Accumulated Depreciation	Net Plant-in-Service	Construction Work-in-Progress
NPC					
Navajo Facility	11.3	$240,350	$127,507	$112,843	$ 562
Reid Gardner No. 4	32.2	127,970	79,425	48,545	7,538
Silverhawk	75.0	235,241	27,097	208,144	60
Total NPC		$603,561	$234,029	$369,532	$8,160
SPPC					
Valmy Facility	50.0	$293,236	$171,660	$121,576	$9,132

The amounts for Navajo include NPC's share of transmission systems, general plant equipment and 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 Income Statements.

NPC is the operator of the Silverhawk Generating Station, which is jointly owned with Southern Nevada Water Authority. NPC owns 75% and its share of direct operation and maintenance expense is included in its accompanying Consolidated Income Statements.

NPC has an approximate 14% ownership in the Mohave Generating Station ("Mohave"). Southern California Edison is the operating partner of Mohave. On December 31, 2005, Mohave ceased operations due to unresolved legal matters; as such, it was reclassified from Plant-in-Service to Other Regulatory Assets as of December 31, 2005. See Note 13, Commitments and Contingencies, for further discussion of Mohave.

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 Income Statements.

NOTE 6. LONG-TERM DEBT

As of December 31, 2006, 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 and thereafter are shown below (dollars in thousands):

	NPC	SPPC	SPR Holding Co. and Other Subs.	SPR Consolidated
2007	$ 5,948	$ 2,400	$ —	$ 8,348
2008	7,068	322,400	—	329,468
2009	22,138	80,600	—	102,738
2010	7,843	—	—	7,843
2011	369,734	—	—	369,734
	412,731	405,400	—	818,131
Thereafter	1,986,113	668,250	549,209	3,203,572
	2,398,844	1,073,650	549,209	4,021,703
Unamortized premium (discount) amount	(12,757)	(392)	1,336	(11,813)
Total	$2,386,087	$1,073,258	$550,545	$ 4,009,890

The preceding table includes obligations related to capital lease obligations discussed under lease commitments within this note.

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

Nevada Power Company

POLLUTION CONTROL REFUNDING REVENUE BONDS, SERIES 2006, 2006A AND 2006B In August 2006, on behalf of NPC, Clark County, Nevada (Clark County), issued $39.5 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006, due January 2036. On the same date, on behalf of NPC, Coconino County, Arizona Pollution Control Corporation (Coconino County), issued $40 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006A, due September 2032, and $13 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006B, due March 2039.

In connection with the issuance of these Bonds, NPC entered into financing agreements with Clark County and Coconino County, pursuant to which Clark County and Coconino County loaned the proceeds from the sales of the bonds to NPC. NPC's payment obligations under the financing agreements are secured by NPC's General and Refunding Mortgage Notes, Series P.

The interest rates of the Bonds were initially determined by an auction. The method of determining the interest rate on the Bonds may be converted from time to time so that such Bonds would thereafter bear interest at a daily, weekly, flexible, auction or term rate as designated.

The proceeds of the offering were used to refund the following, all of which were previously issued for the benefit of NPC:

- $39.5 million principal amount of Clark County's Pollution Control Refunding Revenue Bonds, Series 1992B,
- $20 million principal amount of Coconino County's Pollution Control Revenue Bonds, Series 1996,
- $20 million principal amount of Coconino County's Pollution Control Revenue Bonds, Series 1997B, and
- $13 million principal amount of Coconino County's Pollution Control Revenue Bonds, Series 1995E.

GENERAL AND REFUNDING MORTGAGE NOTES, SERIES O In May 2006, NPC issued and sold $250 million in aggregate principal amount of 6.5% General and Refunding Mortgage Notes, Series O, due 2018. The Series O Notes were issued with registration rights. Proceeds of the offering, together with available cash, were utilized to:

- fund the early redemption of $78 million aggregate principal amounts of NPC's 7.2% Industrial Development Revenue Bonds, Series 1992 C, due 2022,
- fund the early redemption, in June 2006, of approximately $72.2 million aggregate principal amount of NPC's 7.75% Junior Subordinated Debentures due 2038 (when the debentures were repaid upon redemption, the proceeds from the repayment were used to simultaneously redeem an equal amount of the 7.75% Cumulative Quarterly Preferred Securities of NVP Capital III, a wholly-owned subsidiary of NPC),
- repay amounts outstanding under NPC's revolving credit facility.

In June 2006, NPC issued an additional $75 million in aggregate principal amount of its 6.5% General and Refunding Mortgage Notes, Series O, as part of the same series as the original Series O Notes. The aggregate principal amount of 6.5% General and Refunding Mortgage Notes, Series O, due 2018, outstanding is $325 million as of December 31, 2006. The proceeds from the second issuance, along with the proceeds from an offering of $120 million of NPC's 6.65% General and Refunding Mortgage Notes, Series N, due 2036 (described below) were used to pay the total consideration for the tender offer for the 10.875% General and Refunding Mortgage Notes, Series E, described below.

GENERAL AND REFUNDING MORTGAGE NOTES, SERIES N In April 2006, NPC issued and sold $250 million of its 6.65% General and Refunding Mortgage Notes, Series N, due April 2036. The Series N Notes were issued with registration rights. Proceeds of the offering, together with available cash, were utilized to:

- fund the early redemption of $35 million aggregate principal amount of NPC's 8.50% Series Z First Mortgage Bonds due 2023 plus approximately $1 million of associated redemption premiums,

- fund the early redemption of $105 million aggregate principal amount of 6.70% Industrial Development Revenue Bonds, due 2022, and
- fund the early redemption of approximately $122.5 million aggregate principal amount of NPC's 8.20% Junior Subordinated Debentures due 2037 (when the Debentures were repaid upon redemption, the proceeds from the repayment were used to simultaneously redeem an equal amount of the 8.20% Cumulative Quarterly Preferred Securities of NVP Capital I, a wholly-owned subsidiary of NPC).

In June 2006, NPC issued an additional $120 million in aggregate principal amount of its 6.65% General and Refunding Mortgage Notes, Series N, as part of the same series as the original Series N Notes. The aggregate principal amount of 6.65% General and Refunding Mortgage Notes, Series N, due 2036, outstanding is $370 million as of December 31, 2006. The proceeds from the second issuance, along with the proceeds from an offering of $75 million of NPC's 6.5% General and Refunding Mortgage Notes, Series O, due 2018 (described above) were used to pay the total consideration for the tender offer on the 10.875% General and Refunding Mortgage Notes, Series E, described below.

GENERAL AND REFUNDING MORTGAGE NOTES, SERIES M In January 2006, NPC issued and sold $210 million of its 5.95% General and Refunding Mortgage Notes, Series M, due March 2016. The Series M Notes were issued with registration rights. In February 2006 the net proceeds of the issuance plus available cash were used to repay $210 million of amounts outstanding under NPC's revolving credit facility, which were borrowed to finance the purchase of a 75% ownership interest in the Silverhawk Generating Facility.

REVOLVING CREDIT FACILITY In November 2005, NPC amended and restated its existing secured $350 million revolving credit facility, maturing in October 2007, reducing the fees on both the unused portion of the facility and on the amounts borrowed, increasing the size of the facility to $500 million, extending the maturity to November 2010 and changing the Administrative Agent for the facility to Wachovia Bank, National Association. The rate for outstanding loans and/or letters of credit under the revolving credit facility will be at either an applicable base rate (defined as the higher of the Prime rate and the Federal Funds rate plus one-half of one percent) or a Eurodollar rate plus a margin that varies based upon NPC's credit rating by at least two of the three rating agencies: Standard & Poor's ("S&P"), Moody's Investors Service, Inc. ("Moody's") and Fitch Ratings Ltd. ("Fitch"). Currently, the base rate is Prime, and NPC's applicable base rate margin is zero. The Eurodollar margin is 0.875%.

In April 2006, NPC increased the size of the credit facility to $600 million. The facility will provide additional liquidity for increased commodity prices and temporary bridge financing of capital expenditures. As of December 31, 2006, NPC had $55 million of letters of credit outstanding and had no borrowings outstanding under the revolving credit facility. As of February 23, 2007, NPC had $48.7 million of letters of credit outstanding and had $75 million borrowed under the revolving credit facility.

The NPC Credit Agreement contains two financial maintenance covenants. The first requires that NPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that NPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1. As of December 31, 2006, NPC was in compliance with these covenants.

The NPC Credit Agreement provides for an event of default if there is a failure under NPC's other financing agreements to meet certain payment terms or to observe other covenants that would result in an acceleration of payments due.

The NPC Credit Agreement places certain restrictions on debt incurrence, liens and dividends. These restrictions are discussed in Note 8, Debt Covenant and Other Restrictions.

Other Redemptions

GENERAL AND REFUNDING MORTGAGE NOTES, SERIES G In July 2005, NPC redeemed $122,500,000 aggregate principal amount of its 9% General and Refunding Mortgage Notes, Series G, due 2013. This redemption constituted 35% of the principal amount outstanding. The Series G Notes were redeemed at a redemption price equal to $1,090.00 for each $1,000 note redeemed for a redemption premium in excess of the principal amount of approximately $11 million. In accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation," the redemption premium to redeem the debt will be amortized over the original term of the debt.

GENERAL AND REFUNDING MORTGAGE NOTES, SERIES E In July 2005, NPC redeemed $87,500,000 aggregate principal amount of its 10.875% General and Refunding Mortgage Notes, Series E, due 2009. This redemption constituted 35% of the principal amount outstanding. The Series E Notes were redeemed at a redemption price equal to $1,108.75 for each $1,000 note redeemed for a redemption premium in excess of the principal amount of approximately $9.5 million. In accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation," the redemption premium to redeem the debt will be amortized over the original term of the debt. NPC paid for the redemption with the proceeds of an equity contribution of approximately $230.5 million from SPR.

TENDER OFFER FOR GENERAL AND REFUNDING MORTGAGE NOTES, SERIES E In June 2006, NPC commenced a tender offer for the remaining 10.875% General and Refunding Mortgage Notes, Series E, due 2009. In conjunction with that offer, NPC solicited the consent of holders of a majority in aggregate principal amount of the Series E Notes to eliminate substantially all of the restrictive covenants contained in the officer's certificate governing the Series E Notes. Approximately $150 million of $162.5 million Series E Notes outstanding were validly tendered and accepted by NPC. Those holders who tendered the Series E Notes and delivered their consents by June 14, 2006 were entitled to receive a consent payment of $30 per $1,000 principal amount of Series E Notes, plus tender consideration for each $1,000 principal amount of Series E Notes validly tendered. Those holders who tendered the Series E Notes after June 14, 2006, but prior to June 28, 2006, were entitled to receive the tender consideration only. This tender

consideration was $1,038.45 in cash plus accrued and unpaid interest up to the June 2006 settlement date per $1,000 principal amount of the Series E Notes tendered. Proceeds from the June 2006 issuance of Series N and Series O Notes (discussed above) were used to fund the tender offer. The total consideration (including the consent payment and accrued interest) paid in June 2006 was approximately $163.6 million. In October 2006, NPC redeemed the remaining $12.6 million aggregate principal amount of the Series E Notes, plus accrued interest, using available cash on hand.

NVP CAPITAL I TRUST In April 2006, NPC's 8.20% Junior Subordinated Debentures due 2037 were redeemed. When the Debentures were repaid upon redemption, the proceeds from the repayment were used to simultaneously redeem an equal amount of the 8.20% Cumulative Quarterly Preferred Securities of NVP Capital I.

NVP CAPITAL III TRUST In June 2006, NPC's 7.75% Junior Subordinated Debentures due 2038 were redeemed. When the Debentures were repaid upon redemption, the proceeds from the repayment were used to simultaneously redeem an equal amount of the 7.75% Cumulative Quarterly Preferred Securities of NVP Capital III.

Sierra Pacific Power Company

POLLUTION CONTROL AND GAS AND WATER FACILITIES REFUNDING REVENUE BONDS, SERIES 2006, 2006A, 2006B AND 2006C In November 2006, on behalf of SPPC, Humboldt County, Nevada (Humboldt County), issued $49.75 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006, due October 2029. On the same date, on behalf of SPPC, Washoe County, Nevada (Washoe County), issued $58.7 million aggregate principal amount of its Gas Facilities Refunding Revenue Bonds, Series 2006A, due August 2031; $75 million aggregate principal amount of its Water Facilities Refunding Revenue Bonds, Series 2006B, due March 2036; and $84.8 million aggregate principal amount of its Gas and Water Facilities Refunding Revenue Bonds, Series 2006C, due March 2036.

In connection with the issuance of these Bonds, SPPC entered into financing agreements with Humboldt County and Washoe County, pursuant to which Humboldt County and Washoe County loaned the proceeds from the sales of the bonds to SPPC. SPPC's payment obligations under the financing agreements are secured by SPPC's General and Refunding Mortgage Notes, Series N.

The interest rates of the Bonds were initially determined by an auction. The method of determining the interest rate on the Bonds may be converted from time to time so that such Bonds would thereafter bear interest at a daily, weekly, flexible, auction or term rate as designated.

The proceeds of the offerings were used to refund the following, all of which were previously issued for the benefit of SPPC:

- $17.5 million principal amount of 6.65% Washoe County's Gas Facilities Refunding Revenue Bonds, Series 1987
- $20 million principal amount of 6.55% Washoe County's Gas Facilities Refunding Revenue Bonds, Series 1990
- $21.2 million principal amount of 6.70% Washoe County's Gas Facilities Refunding Revenue Bonds, Series 1992
- $75 million principal amount of 6.65% Washoe County's Water Facilities Refunding Revenue Bonds, Series 1987
- $45 million principal amount of 6.30% Washoe County's Gas and Water Facilities Refunding Revenue Bonds, Series 1987
- $30 million principal amount of 5.90% Washoe County's Gas and Water Facilities Refunding Revenue Bonds, Series 1993B
- $9.8 million principal amount of 5.90% Washoe County's Water Facilities Refunding Revenue Bonds, Series 1993A
- $39.5 million principal amount of 6.55% Humboldt County's Pollution Control Refunding Revenue Bonds, Series 1987
- $10.25 million principal amount of 6.30% Humboldt County's Pollution Control Refunding Revenue Bonds, Series 1992A

HUMBOLDT COUNTY POLLUTION CONTROL REFUNDING REVENUE BONDS In October 2006, the 6.35% Humboldt County Pollution Control Refunding Revenue Bonds, Series 1992B, due August 2022, in the amount of $1 million were redeemed at 100% of the stated principal amount, plus accrued interest.

GENERAL AND REFUNDING MORTGAGE NOTES, SERIES M In March 2006, SPPC issued and sold $300 million of its 6.00% General and Refunding Mortgage Notes, Series M, due May 2016. The Series M Notes were issued with registration rights. Proceeds of the offering were used to repay $173 million borrowed under the revolving credit facility that was utilized to:

- fund the early redemption of $110 million aggregate principal amount of SPPC's Collateralized Medium Term 6.95% to 8.61% Series A Notes due 2022;
- fund the early redemption of $58 million aggregate principal amount of SPPC's Collateralized Medium Term 7.10% to 7.14% Series B Notes due 2023;
- pay for maturing debt of $30 million aggregate principal amount of SPPC's Collateralized Medium Term 6.81% to 6.83% Series C Notes due 2006;
- pay for $51 million in connection with the redemption of $50 million of SPPC's Series A Preferred Stock (two million shares of stock were redeemed at a redemption price per share of $25.683, plus accrued dividends to the redemption date of $.4875 per share); and
- pay for maturing debt of $20 million aggregate principal amount of SPPC's Collateralized Medium Term 6.62% to 6.65% Series C Notes due 2006.

REVOLVING CREDIT FACILITY In November 2005, SPPC amended and restated its existing secured $50 million revolving credit facility, maturing in October 2007, reducing the fees on both the unused portion of the facility, and on the amounts borrowed, increasing the size of the facility, to $250 million, extending the maturity to November 2010 and changing the Administrative Agent for the facility to Wachovia Bank, National Association. The rate for outstanding loans and/or letters of credit under the revolving credit facility will be at either an applicable base rate (defined as the higher of the Prime rate and the Federal Funds rate plus one-half of one percent) or a Eurodollar rate, plus a margin that varies based upon SPPC's credit rating by at least two of the three

rating agencies (S&P, Moody's and Fitch). Currently, the base rate is Prime and SPPC's applicable base rate margin is zero. The current Eurodollar margin is 0.875%.

In April 2006, SPPC increased the size of its credit facility to $350 million. The facility will provide additional liquidity for increased commodity prices and temporary bridge financing of capital expenditures. As of December 31, 2006, SPPC had $9.4 million of letters of credit outstanding and had no amounts borrowed under the revolving credit facility. As of February 23, 2007, SPPC had $18.9 million of letters of credit and had no amounts borrowed under the revolving credit facility.

The SPPC Credit Agreement contains two financial maintenance covenants. The first requires that SPPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that SPPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1. As of December 31, 2006, SPPC was in compliance with these covenants.

The SPPC Credit Agreement provides for an event of default if there is a failure under SPPC's other financing agreements to meet certain payment terms or to observe other covenants that would result in an acceleration of payments due.

The SPPC Credit Agreement, similar to SPPC's Series H Notes, places certain restrictions on debt incurrence, liens and dividends. These limitations are discussed in Note 8, Debt Covenant and Other Restrictions.

Sierra Pacific Resources

TENDER OFFER In November 2006, SPR commenced tender offers for up to $110 million aggregate principal amount of its 7.803% Senior Notes due 2012, its 8.625% Senior Notes due 2014, and its 6.75% Senior Notes due 2017. Each of the offers was conditioned on SPR purchasing no more than an aggregate principal amount of $110 million of all notes validly tendered. To meet this condition, SPR terminated the offer for the 6.75% Notes. In December 2006, approximately $25 million of the 7.803% Senior Notes outstanding, and approximately $85 million of the 8.625% Senior Notes outstanding were validly tendered and accepted by SPR. The total consideration paid was approximately $120.6 million (which included an early tender premium and accrued interest). As of December 31, 2006, the outstanding balances for the 7.803% Senior Notes and 8.625% Senior Notes were $74.2 million and $250.0 million, respectively.

7.803% SENIOR NOTES In May 2005, SPR issued $99,142,000 aggregate principal amount of 7.93% Senior Notes, due 2007. These senior notes replaced the notes associated with the Premium Income Equity Securities (Old PIES), which were originally issued in November 2001. SPR successfully remarketed these notes in June 2005. In connection with the remarketing, the interest rate of the Senior Notes was reset to 7.803% per annum, effective on and after June 14, 2005. The remarketed Senior Notes will mature in June 2012. In December 2006, a portion of these Notes were tendered. (See Tender Offer above). As of December 31, 2006, $74.2 million aggregate principal amount of the 7.803% Senior Notes remain outstanding.

6.75% SENIOR NOTES In August 2005, SPR conducted a private placement of $225 million 6.75% Senior Notes due 2017. The proceeds were used to repurchase approximately $141 million 7.93% Senior Notes associated with the Old PIES; pay approximately $54 million in premiums associated with the conversion of the 7.25% Notes and fund the associated fees and expenses; and to provide additional liquidity to SPR.

8.625% SENIOR NOTES In March 2004, SPR issued and sold $335 million 8.625% Senior Unsecured Notes due March 2014. The Senior Unsecured Notes, which were issued with registration rights, were exchanged for registered notes in October 2004. The proceeds of the issuance were used to fund the repurchase of approximately $174 million in principal amount of SPR's 8.75% Notes due 2005 at a price equal to approximately 107.225% of the principal amount thereof that were tendered pursuant to SPR's tender offer.

The balance of the net proceeds were used in May 2004 to legally extinguish the approximately $126 million of remaining principal amount of SPR's 8.75% Notes due 2005 which were not tendered, and to pay associated interest and fees and expenses associated with the tender offer and the Notes offering. The total cost to extinguish the debt was approximately $23.7 million, consisting of tender fees, interest costs and unamortized debt issuance costs.

In December 2006, a portion of the 8.625% Senior Unsecured Notes were tendered (See Tender Offer above). As of December 31, 2006, $250 million aggregate principal amount of the 8.625% Senior Notes remain outstanding.

Lease Commitments

In 1984, NPC entered into a 30-year capital lease with five-year renewal options beginning in year 2015. The fixed rental obligation for the first 30 years is $5.1 million per year. Also, NPC has a power purchase 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 capital leases, combined, as of December 31, 2006, were as follows (dollars in thousands):

2007	$ 5,933
2008	7,053
2009	7,138
2010	7,843
2011	5,734
Thereafter	16,778

NOTE 7. FAIR VALUE OF FINANCIAL INSTRUMENTS

The December 31, 2006 carrying amount of 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, 2006 is estimated to be $2.5 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 $2.2 billion at December 31, 2005.

The total fair value of SPPC's consolidated long-term debt at December 31, 2006 is estimated to be $1.1 billion (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 $1.0 billion as of December 31, 2005.

The total fair value of SPR's consolidated long-term debt at December 31, 2006 is estimated to be $4.1 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 $3.9 billion as of December 31, 2005.

NOTE 8. DEBT COVENANT AND OTHER RESTRICTIONS

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 impose limits on investment returns or otherwise impact the amount of dividends that the Utilities may declare and pay. In the PUCN Order for Docket 05-10024 and 05-10025, issued in February 2006, a dividend restriction was instituted for both Utilities. Under this restriction, the combined amount that NPC and SPPC may pay to SPR each year is limited to the actual cash necessary to service SPR's debt for the year. At the time of the order, SPR and the Utilities were only rated by Standard & Poor's ("S&P"), Moody's Investors Service, Inc. ("Moody's") and Fitch Ratings Ltd. ("Fitch"). The PUCN Order states that the dividend restriction will continue until NPC's and SPPC's senior secured debt obtains an investment grade rating from two of the three credit rating agencies, but did not specify which rating agencies. In February 2007, Dominion Bond Rating Service ("DBRS"), who had not previously issued ratings on the companies, assigned ratings for SPR, NPC and SPPC. DBRS and Fitch currently rate NPC and SPPC's senior secured debt at the minimum level for investment grade. It is not clear what effect, if any, the DBRS rating will have on the PUCN dividend restriction. See Credit Ratings below for discussion of current ratings.

In addition, certain agreements entered into by the Utilities set restrictions on certain restricted payments, including the amount of dividends they may declare and pay and restrict the circumstances under which such dividends may be declared and paid.

In addition, covenants of certain SPR, NPC and SPPC debt limit the company's ability to incur additional debt. Material restrictions on dividends and on debt incurrence contained in SPR's and the Utilities' financing agreements are summarized below. All securities issued by NPC and SPPC must be authorized by the PUCN.

Limits on Restricted Payments

SIERRA PACIFIC RESOURCES SPR has paid no dividends since 2002. Dividends are considered periodically by SPR's Board of Directors and are subject to factors that ordinarily affect dividend policy, such as current and prospective earnings, current and prospective business conditions, regulatory factors, SPR's financial conditions and other matters within the discretion of the Board, as well as dividend restrictions set forth in SPR's 8⅝% Senior Notes due 2014, 7.803% Senior Notes due 2012 and 6.75% Senior Notes due 2017. The Board will continue to review the factors described above on a periodic basis to determine if and when it would be prudent to declare a dividend on SPR's common stock. There is no guarantee that dividends will be paid in the future, or that, if paid, the dividends will be paid at the same amount or with the same frequency as in the past.

Certain of SPR debt contain covenants that limit restricted payments, which include dividends. If SPR were to resume paying a dividend, these restrictive covenants must first be satisfied. SPR must be able to incur additional indebtedness, as determined under a 2-to-1 fixed charge coverage ratio test. If that condition is met, the amount of dividends that can be paid is less than (i) 50% of the Consolidated Net Income for SPR for the period from April 1, 2004 to the end of the most recently ended fiscal quarter for which internal financial statements are available at the time of such payment, plus (ii) 100% of SPR's net cash proceeds from the issuance or sale of its equity interests, including common stock. Since SPR meets the 2-to-1 fixed charge coverage ratio test, it could dividend up to a maximum of $740 million as of December 31, 2006. Under its most restrictive covenants, SPR can additionally pay up to an aggregate of $50 million in dividends during the period from April 1, 2004 to the end of the most recently ended fiscal quarter.

Material Dividend Restrictions Applicable to Nevada Power Company

- The following notes and credit agreement limit the amount of payments in respect of common stock that NPC may make to SPR:
  - NPC's 5⅞% General and Refunding Mortgage Notes, Series L, due 2015, which were issued in November 2004,
  - NPC's Revolving Credit Agreement, which was amended and restated in November 2005,
  - NPC's 6½% General and Refunding Mortgage Notes, Series I, due 2012, which were issued in April 2004, and
  - NPC's 9% General and Refunding Mortgage Notes, Series G, due 2013, which were issued in August 2003.

  However, the dividend payment limitation does not apply to payments by NPC to enable SPR to pay its reasonable fees and expenses, 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 various series of Notes and the Revolving Credit Agreement also permit NPC to make payments to SPR in excess of the amounts payable discussed above in an aggregate amount not to exceed:

- under the Series G, Series I and Series L Notes, $25 million from the date of the issuance of the Series G, Series I and Series L Notes, respectively.
- Under the Second Amended and Restated Revolving Credit Facility, $50 million from the date of the establishment of the Amended and Restated Revolving Credit Facility.

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:

i. there are no defaults or events of default with respect to the Series G, I and L Notes or the NPC Revolving Credit Agreement,

ii. 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 to 1, and

iii. the total amount of such dividends is less than:
    - the sum of 50% of NPC's consolidated net income measured on a annual basis cumulative of all quarters from the date of issuance of the applicable series of Notes, the Bond or Credit Agreement, 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.

Since NPC meets (i) and (ii) above, NPC would be able to pay up to a maximum of $609 million to SPR as of December 31, 2006. However, the total amount of dividends that NPC can pay to SPR under its financing agreements does not currently significantly restrict their ability to pay dividends because the maximum amount of dividends that can be paid under its financing agreements is greater than the amount that NPC can pay under the PUCN dividend restriction.

If NPC's Series E Notes, Series G Notes, Series I Notes, or Series L Notes are upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable series of Notes remains investment grade (see Credit Ratings below).

Material Dividend Restrictions Applicable to Sierra Pacific Power Company

- The following notes and credit facility limit the amount of payments in respect of common stock that SPPC may make to SPR:
    - SPPC's Revolving Credit Agreement, which was amended and restated in November 2005, and
    - SPPC's 6¼% General and Refunding Mortgage Notes, Series H, due 2012, which were issued in April 2004.

  However, the dividend payment limitation does not apply to payments by SPPC to enable SPR to pay its reasonable fees and expenses provided that:
    - those payments do not exceed $50 million for any one calendar year,
    - those payments comply with any regulatory restrictions then applicable to SPPC, and
    - the ratio of consolidated cash flow to fixed charges for SPPC'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 H Notes also permit SPPC to make payments to SPR in excess of the amounts payable discussed above in an aggregate amount not to exceed $25 million from the date of the issuance of the Series H Notes.

  The terms of the Amended and Restated Revolving Credit Facility also permit SPPC to make payments to SPR in excess of the amounts payable above in an aggregate amount not to exceed $50 million from the date of the establishment of the Amended and Restated Revolving Credit Facility.

  In addition, SPPC 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:

  i. there are no defaults or events of default with respect to the Series H Notes or the SPPC Revolving Credit Agreement,

  ii. SPPC has a ratio of consolidated cash flow to fixed charges for SPPC's most recently ended four full fiscal quarters immediately preceding the payment date of at least 2 to 1, and

  iii. the total amount of such dividends is less than:
      - the sum of 50% of SPPC's consolidated net income measured on an annual basis cumulative of all quarters from the date of issuance of the Series H Notes or the establishment of the Revolving Credit Agreement, plus
      - 100% of SPPC'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 SPPC, plus
      - the lesser of cash return of capital or the initial amount of certain restricted investments, plus
      - the fair market value of SPPC's investment in certain subsidiaries.

Since SPPC meets (i) and (ii) above, SPPC would be able to pay up to a maximum of $126 million to SPR as of December 31, 2006. However, the total amount of dividends that SPPC can pay to SPR under its financing agreements does not currently significantly restrict their ability to pay dividends because the maximum amount of dividends that can be paid under its financing agreements is greater than the amount that SPPC can pay under the PUCN dividend restriction.

If SPPC's Series H Notes are upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable series of Notes remain investment grade (see Credit Ratings below).

DIVIDEND RESTRICTIONS APPLICABLE TO THE UTILITIES 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 their capital account. Although the meaning of this provision is unclear, the Utilities believe that the Federal Power Act restriction, as applied to their particular circumstances, would not be construed or applied by the FERC to prohibit the payment of dividends for lawful and legitimate business purposes from current year earnings, or in the absence of current year earnings, from other/additional paid-in capital accounts. If, however, the FERC were to interpret this provision differently, the ability of the Utilities to pay dividends to SPR could be jeopardized.

Limitations on Indebtedness

SIERRA PACIFIC RESOURCES Certain debt of SPR places restrictions on debt incurrence, liens and dividends, unless, at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for SPR's most recently ended four-quarter period on a pro forma basis is at least 2 to 1. Under this covenant restriction, as of December 31, 2006, SPR would be allowed to incur up to $2.1 billion of additional indebtedness on a consolidated basis.

Notwithstanding this restriction, under the terms of the debt, SPR would still be permitted to incur debt including, but not limited to, obligations incurred to finance property construction or improvement, certain intercompany indebtedness, or indebtedness incurred to finance capital expenditures, pursuant to the two utilities' integrated resource plans. NPC and SPPC would also be permitted to incur a combined total of up to $500 million in indebtedness and letters of credit under their respective revolving credit facilities.

If the debt is upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable series of Notes remains investment grade (see Credit Ratings below).

NEVADA POWER COMPANY Certain debt of NPC places restrictions on debt incurrence, liens and dividends, unless, 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. Under this covenant restriction, as of December 31, 2006, NPC would be allowed to incur $2.2 billion of additional indebtedness. However, due to the terms of the SPR debt described above, NPC's and SPPC's combined debt limit is restricted to the $2.1 billion of additional indebtedness SPR could incur on a consolidated basis.

Under the terms of NPC's debt, NPC would also be permitted to incur debt, including, but not limited to, obligations incurred to finance property construction or improvements, certain intercompany indebtedness, certain letters of credit indebtedness, or indebtedness incurred to finance capital expenditures, pursuant to NPC's 2006 Integrated Resource Plan.

If the debt containing these covenants is upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable debt remains investment grade (see Credit Ratings below).

SIERRA PACIFIC POWER COMPANY Certain debt of SPPC places restrictions on debt incurrence, liens and dividends, unless, at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for SPPC's most recently ended four-quarter period on a pro forma basis is at least 2 to 1. Under this covenant restriction, as of December 31, 2006, SPPC would be allowed to incur up to $797 million of additional indebtedness on a consolidated basis. However, due to the terms of the SPR debt described above, NPC's and SPPC's combined debt limit is restricted to the $2.1 billion of additional indebtedness SPR could incur on a consolidated basis.

Under the terms of SPPC's debt, SPPC would also be permitted to incur debt including, but not limited to, obligations incurred to finance property construction or improvements, certain intercompany indebtedness, certain letters of credit indebtedness, or indebtedness incurred to finance capital expenditures, pursuant to SPPC's 2004 Integrated Resource Plan.

If the debt containing these covenants is upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable debt remains investment grade (see Credit Ratings below).

CREDIT RATINGS SPR, NPC and SPPC are rated by four Nationally Recognized Statistical Rating Organizations: S&P, Moody's, Fitch, and Dominion Bond Rating Service ("DBRS"). As of February 23, 2007, the ratings are as follows:

		Rating Agency			
		DBRS	Fitch	Moody's	S&P
SPR	Sr. unsecured debt	BB (low)	BB-	B1	B
NPC	Sr. secured debt	BBB (low)*	BBB-*	Ba1	BB+
NPC	Sr. unsecured debt	Not rated	BB	Not rated	B
SPPC	Sr. secured debt	BBB (low)*	BBB-*	Ba1	BB+

** Ratings are investment grade*

In February 2007, DBRS, who had not previously issued ratings on the companies, assigned new ratings to SPR, NPC and SPPC. The ratings for the senior secured debt of NPC and SPPC are BBB (low), which is the minimum level for investment grade. The rating assigned to SPR's senior notes is BB (low), which is non-investment grade. DBRS's trend for all three companies is Stable.

In 2006, there were other changes to the ratings of the three companies. Fitch upgraded the ratings of SPR and the Utilities. The ratings for the senior secured debt of NPC and SPPC were increased to BBB-, the minimum level for investment grade. The senior unsecured debt for NPC was upgraded from BB- to BB, which is still non-investment grade. Fitch revised the rating outlook for SPR and the Utilities from

Positive to Stable. S&P upgraded the ratings of NPC's and SPPC's senior secured debt from BB to BB+, one level below investment grade. Moody's re-affirmed its ratings for NPC's and SPPC's senior secured debt at Ba1, one level below investment grade.

At the time of the PUCN Order for Dockets 05-10024 and 05-10025 (see Dividends from Subsidiaries, above), SPR and the Utilities were only rated by S&P, Moody's and Fitch. The PUCN Order states that the dividend restriction will continue until NPC's and SPPC's senior secured debt obtains an investment grade rating from two of the three credit rating agencies, but did not specify which rating agencies. It is not clear what effect the DBRS rating will have on the PUCN dividend restriction.

NOTE 9. DERIVATIVES AND HEDGING ACTIVITIES (SPR, NPC, SPPC)

SPR, SPPC and NPC apply SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, SFAS No. 149 and SFAS No. 155. As amended, SFAS No. 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It 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 meets certain defined conditions and qualifies as an effective hedge. SFAS No. 133 also provides a scope exception for contracts that meet the normal purchase and sales criteria specified in the standard. The normal purchases and normal sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Contracts that are designated as normal purchase and normal sales are accounted for under deferred energy accounting and not recorded on the Consolidated Balance Sheets at fair value. A majority of the contracts entered into by the Utilities meet the criteria specified for this exception.

The energy supply function encompasses the reliable and efficient operation of the Utilities generation, the procurement of all fuels and power and resource optimization (i.e., physical and economic dispatch) and is exposed to risks relating to, but not limited to, changes in commodity prices. SPR's and the Utilities' objective in using derivative instruments is to reduce exposure to energy price 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 from time to time may include: forward contracts, which involve physical delivery of an energy commodity; over-the-counter options with financial institutions and other energy companies, which mitigate price risk by providing the right, but not the requirement, to buy or sell energy related commodities at a fixed price; and swaps, which require the Utilities to receive or make payments based on the difference between a specified price and the actual price of the underlying commodity. These contracts allow the Utilities to reduce the risks associated with volatile electricity and natural gas markets.

The following table shows the fair value of the open derivative positions recorded on the Consolidated Balance Sheets of SPR, NPC and SPPC, and the related regulatory assets/liabilities that did not meet the normal purchase and normal sales exception criteria in SFAS No. 133. The fair values of the open derivative positions are determined using quoted exchange prices, external dealer prices, and available market pricing curves. Due to deferred energy accounting treatment under which the Utilities operate, regulatory assets and liabilities are established to the extent that electricity and natural gas derivative gains and losses are recoverable or payable through future rates, once realized. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement and to not recognize gains and losses on the Consolidated Statements of Income:

	December 31, 2006 Fair Value		
	SPR	**NPC**	**SPPC**
(dollars in millions)			
Risk management assets—current	**$ 27.3**	**$16.4**	**$10.9**
Risk management assets—noncurrent	**$ 7.6**	**$ 5.4**	**$ 2.2**
Total risk management assets	**$ 34.9**	**$21.8**	**$13.1**
Risk management liabilities—current	**$123.1**	**$84.7**	**$38.4**
Risk management liabilities—noncurrent	**$ 10.8**	**$ 7.1**	**$ 3.7**
Total risk management liabilities	**$133.9**	**$91.8**	**$42.1**
Risk management regulatory net assets (liabilities)	**$122.9**	**$83.9**	**$39.0**

	December 31, 2005 Fair Value		
	SPR	NPC	SPPC
(dollars in millions)			
Risk management assets—current	$ 50.2	$ 22.4	$ 27.8
Risk management assets—noncurrent	$ —	$ —	$ —
Total risk management assets	$ 50.2	$ 22.4	$ 27.8
Risk management liabilities—current	$ 16.6	$ 10.1	$ 6.5
Risk management liabilities—noncurrent	$ —	$ —	$ —
Total risk management liabilities	$ 16.6	$ 10.1	$ 6.5
Risk management regulatory net assets (liabilities)	$ (15.6)	$ (0.6)	$(15.0)

As a result of the nature of operations and the use of mark-to-market accounting for certain derivatives that do not meet the normal purchase and normal sales exception criteria, mark-to-market fair values will fluctuate. The Utilities cannot predict these fluctuations, but the primary factors that cause changes in the fair values are the number and size of the Utilities' open derivative positions with its counterparties and the changes in forward commodity prices. The decrease in net risk management assets as of December 31, 2006 as compared to December 31, 2005 is due to unfavorable open derivative positions on natural gas options held by the Utilities to hedge energy price risk for their customers, resulting from lower commodity prices for natural gas in 2006 relative to contract prices.

Also included in total risk management assets were $24.0 million, $13.9 million and $10.1 million in payments for electric and gas options by SPR, NPC and SPPC, respectively, at December 31, 2006.

NOTE 10. INCOME TAXES (BENEFITS)

Sierra Pacific Resources

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

	2006	2005	2004
Provision (benefit) for income taxes			
Current			
Federal	**$ 5,914**	$ 3,159	$ (161)
State	**—**	—	—
Total current	**5,914**	3,159	(161)
Deferred			
Federal	**144,919**	43,833	24,448
State	**494**	1,688	(775)
Total deferred	**145,413**	45,521	23,673
Amortization of excess deferred taxes	**(2,315)**	(2,123)	(2,196)
Amortization of investment tax credits	**(3,407)**	(3,439)	(3,266)
Total provision for income taxes	**$145,605**	$43,118	$18,050
Income statement classification of provision (benefit) for income taxes			
Operating income	**$ 91,571**	$39,185	$22,739
Other income	**54,034**	3,933	(4,689)
Total	**$145,605**	$43,118	$18,050

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

	2006	2005	2004
Income from continuing operations	**$279,792**	$ 86,137	$30,842
Total income tax expense (benefit)	**145,605**	43,118	18,050
Pretax income	**425,397**	129,255	48,892
Statutory tax rate	**35%**	35%	35%
Federal income tax expense at statutory rate	**148,889**	45,239	17,112
Depreciation related to difference in cost basis for tax purposes	**4,709**	4,559	4,834
Allowance for funds used during construction—equity	**(6,379)**	(7,113)	(2,082)
ITC amortization	**(3,407)**	(3,439)	(3,266)
Goodwill	**2,600**	2,230	6,332
Convertible bond mark to market and interest accretion	**—**	2,132	2,786
Pension benefit plan	**338**	(945)	(3,684)
Research and development credit	**(3,764)**	—	—
Other—net	**2,619**	455	(632)
Provision for income taxes before effect of income tax settlements	**$ 145,605**	$ 43,118	$21,400
Effective tax rate before effect of income tax settlements	**34.2%**	33.3%	43.8%
Effects of income tax settlements	**—**	—	(3,350)
Provision for income taxes	**$145,605**	$ 43,118	$18,050
Effective tax rate	**34.2%**	33.3%	36.9%

As a large corporate taxpayer, the SPR consolidated group's tax returns are examined by the Internal Revenue Service (IRS) on a regular basis. The IRS is currently conducting audits of SPR for the years 1997-2004. During the first quarter of 2004, SPR reached tentative agreements with the IRS for certain matters. As a result of the tentative agreements, SPR recognized tax benefits which increased net income by approximately $3.4 million in 2004. SPR believes that it has adequately provided reasonable reserves for reasonable and foreseeable outcomes related to uncertain tax matters.

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

	2006	2005
Deferred income tax assets		
Net operating loss and credit carryovers	**$ 227,834**	$ 247,135
Employee benefit plans	**71,820**	10,190
Customer advances	**32,163**	59,522
Gross-ups received on contribution in aid of construction and customer advances	**31,113**	25,862
Deferred revenues	**1,586**	11,303
Provision for contract termination	**508**	63,427
Other	**22,128**	19,765
Subtotal	**387,152**	437,204
Deferred income tax assets associated with regulatory matters		
Excess deferred income taxes	**15,111**	17,426
Unamortized investment tax credit	**18,964**	20,798
Subtotal	**34,075**	38,224
Total deferred income tax assets before valuation allowance	**421,227**	475,428
Valuation allowance	**(732)**	(984)
Total deferred income tax assets after valuation allowance	**$ 420,495**	$ 474,444
Deferred income tax liabilities		
Excess of tax depreciation over book depreciation	**$ 540,338**	$ 560,702
Deferred energy	**192,653**	180,488
Regulatory assets	**101,375**	20,139
Other	**64,791**	44,819
Subtotal	**899,157**	806,148
Deferred income tax liabilities associated with regulatory matters		
Tax benefits flowed through to customers	**263,170**	249,262
Total deferred income tax liability	**$1,162,327**	$1,055,410
Net deferred income tax liability	**$ 512,737**	$ 369,928
Net deferred income tax liability associated with regulatory matters	**229,095**	211,038
Total net deferred income tax liability	**$ 741,832**	$ 580,966

The total 2006 net deferred income tax liability of $741,832 includes $5,950 of deferred tax liability associated with accumulated depreciation on the Mohave Generating Station, which, on the financial statements, is included in other regulatory assets. Reference Note 13, Commitments and Contingencies, for further discussion of the Mohave Generating Station.

SPR's balance sheets contain a net regulatory asset of $229.1 million at December 31, 2006 and $211.0 million at December 31, 2005. The regulatory asset consists of future revenue to be received from customers due to flow-through of the tax benefits of temporary differences and goodwill recognized from the merger of NPC and SPR. Offset against these amounts are future revenues to be refunded to customers (regulatory liabilities). The regulatory liabilities consist of temporary differences for liberalized depreciation at rates in excess of current rates and 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.

As Reflected in SPR's Balance Sheet:	**2006**	2005
(dollars in thousands)		
Tax benefits flowed through to customers		
Related to property	**$106,175**	$ 98,330
Related to goodwill	**156,995**	150,931
Regulatory tax asset	**263,170**	249,261
Liberalized depreciation at rates in excess of current rates	**15,111**	17,426
Unamortized investment tax credits	**18,964**	20,798
Regulatory tax liability	**34,075**	38,224
Net regulatory tax asset	**$229,095**	$211,037

SPR and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on SPR's and each subsidiaries' respective taxable income or loss and investment tax credits as if each subsidiary filed a separate return. SPR owes NPC $20.6 million in intercompany tax payments. Additionally, per SPR's tax sharing agreement, SPR has a current tax receivable from SPPC of $9.1 million.

The following table summarizes the tax NOL and credit carryforwards and associated carryforward periods, and a valuation allowance for amounts which SPR has determined that realization is uncertain (dollars in thousands):

	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
Federal NOL	$213,024	$ —	$213,024	2020-2023
State NOLs	1,058	—	1,058	2008-2013
Research and development credit	3,764	—	3,764	2021-2025
Alternative minimum tax credit	8,696	—	8,696	indefinite
Arizona coal credits	1,292	732	560	2007-2011
Total	$227,834	$732	$227,102	

At December 31, 2006, SPR has gross federal and state net operating loss carryforwards of $608.6 million and $12.0 million, respectively.

Considering all positive and negative evidence regarding the utilization of SPR's deferred tax assets, it has been determined that SPR is more-likely-than-not to realize all recorded deferred tax assets, except the Arizona coal credits. As such, these Arizona coal credits represent the only valuation allowance that has been recorded as of December 31, 2006.

Nevada Power Company

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

	2006	2005	2004
Provision (benefit) for income taxes			
Current			
Federal	**$ 4,865**	$ 3,159	$ 6
State	**—**	—	—
Total current	**4,865**	3,159	6
Deferred			
Federal	**114,741**	63,873	58,762
State	**268**	(449)	(67)
Total deferred, net	**115,009**	63,424	58,695
Amortization of excess deferred taxes	**(745)**	(778)	(499)
Amortization of investment tax credits	**(1,619)**	(1,810)	(1,630)
Total provision for income taxes	**$117,510**	$63,995	$56,572
Income statement classification of provision for income taxes			
Operating income	**$ 91,781**	$46,425	$45,135
Other income	**25,729**	17,570	11,437
Total	**$117,510**	$63,995	$56,572

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

	2006	2005	2004
Income from continuing operations	**$224,540**	$132,734	$104,312
Total income tax expense	**117,510**	63,995	56,572
Pretax income	**342,050**	196,729	160,884
Statutory tax rate	**35%**	35%	35%
Federal income tax expense at statutory rate	**119,718**	68,855	56,309
Depreciation related to difference in cost basis for tax purposes	**2,192**	1,880	2,144
Allowance for funds used during construction—equity	**(4,114)**	(6,539)	(1,481)
ITC amortization	**(1,619)**	(1,810)	(1,630)
Goodwill	**1,646**	1,386	1,732
Research and development credit	**(1,666)**	—	—
Other—net	**1,353**	223	(502)
Provision for income taxes before effect of income tax settlements	**$117,510**	$ 63,995	$ 56,572
Effective tax rate	**34.4%**	32.5%	35.2%

As a large corporate taxpayer, the SPR consolidated group's tax returns are examined by the IRS on a regular basis. The IRS is currently conducting audits of NPC for the years 1997-2004. NPC believes that has adequately provided reasonable reserves for reasonable and foreseeable outcomes related to uncertain tax matters.

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

	2006	2005
Deferred income tax assets		
Net operating loss and credit carryovers	**$137,344**	$129,420
Employee benefit plans	**29,997**	(530)
Customer advances	**21,014**	34,320
Gross-ups received on contributions in aid of construction and customer advances	**21,844**	18,424
Deferred revenues	**1,586**	11,303
Provision for contract termination	**(4)**	43,737
Other—net	**14,207**	12,797
Subtotal	**225,988**	249,471
Deferred income tax assets associated with regulatory matters		
Excess deferred income taxes	**5,259**	6,005
Unamortized investment tax credit	**8,192**	9,063
Subtotal	**13,451**	15,068
Total deferred income tax assets before valuation allowance	**239,439**	264,539
Valuation allowance	**(732)**	(984)
Total deferred income tax assets after valuation allowance	**$238,707**	$263,555
Deferred income tax liabilities		
Excess of tax depreciation over book depreciation	**$345,135**	$349,056
Deferred energy	**171,113**	140,330
Regulatory assets	**59,092**	11,061
Other—net	**43,299**	28,169
Subtotal	**618,639**	528,616
Deferred income tax liabilities associated with regulatory matters		
Tax benefits flowed through to customers	**153,471**	155,304
Subtotal	**153,471**	155,304
Total deferred income tax liability	**$772,110**	$683,920
Net deferred income tax liability	**$393,383**	$280,129
Net deferred income tax liability associated with regulatory matters	**140,020**	140,236
Total net deferred income tax liability	**$533,403**	$420,365

The total 2006 net deferred income tax liability of $533,403 includes $5,950 of deferred tax liability associated with accumulated depreciation on the Mohave Generating Station, which, on the financial statements, is included in other regulatory assets. Reference Note 13, Commitments and Contingencies, for further discussion of the Mohave Generating Station.

NPC's balance sheet contains a net regulatory asset of $140.0 million at December 31, 2006 and $140.2 million at December 31, 2005. The regulatory asset consists of future revenue to be received from customers due to flow-through of the tax benefits of temporary differences and goodwill recognized from the merger of NPC and SPR. Offset against these amounts are future revenues to be refunded to customers (regulatory liabilities). The regulatory liabilities consist of temporary differences for liberalized depreciation at rates in excess of current rates and 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.

As Reflected in NPC's Balance Sheet:	**2006**	2005
(dollars in thousands)		
Tax benefits flowed through to customers		
Related to property	**$ 55,177**	$ 54,371
Related to goodwill	**98,294**	100,933
Regulatory tax asset	**153,471**	155,304
Liberalized depreciation at rates in excess of current rates	**5,259**	6,005
Unamortized investment tax credits	**8,192**	9,063
Regulatory tax liability	**13,451**	15,068
Net regulatory tax asset	**$140,020**	$140,236

SPR and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on SPR's and each subsidiaries' respective taxable income or loss and investment tax credits as if each subsidiary filed a separate return. SPR owes NPC $20.6 million in intercompany tax payments.

The following table summarizes the tax NOL and credit carryforwards and associated carryforward periods, and a valuation allowance for amounts which NPC has determined that realization is uncertain (dollars in thousands):

Type of Carryforward	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
Federal NOL	$125,681	$ —	$125,681	2020-2023
State NOLs	9	—	9	2008
Research and development credit	1,666	—	1,666	2021-2025
Alternative minimum tax credit	8,696	—	8,696	indefinite
Arizona coal credits	1,292	732	560	2007-2011
Total	$137,344	$732	$136,612	

At December 31, 2006, NPC has gross federal and state net operating loss carryforwards of $359.1 million and $124 thousand, respectively.

Considering all positive and negative evidence regarding the utilization of NPC's deferred tax assets, it has been determined that NPC is more-likely-than-not to realize all recorded deferred tax assets, except some of the Arizona coal credits. As such, these Arizona coal credits represent the only valuation allowance that has been recorded as of December 31, 2006.

Sierra Pacific Power Company

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

	2006	2005	2004
Provision (benefit) for income taxes			
Current			
Federal	**$28,497**	$ 67,291	$ 690
State	**—**	—	—
Total current	**28,497**	67,291	690
Deferred			
Federal	**2,464**	(38,074)	3,676
State	**226**	2,136	(708)
Total deferred	**2,690**	(35,938)	2,968
Amortization of excess deferred taxes	**(1,570)**	(1,345)	(1,697)
Amortization of investment tax credits	**(1,788)**	(1,629)	(1,636)
Total provision for income taxes	**$27,829**	$ 28,379	$ 325
Income statement classification of provision (benefit) for income taxes			
Operating income	**$23,570**	$ 26,038	$ 14,978
Other income	**4,259**	2,341	(14,653)
Total	**$27,829**	$ 28,379	$ 325

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

	2006	2005	2004
Income from continuing operations	**$57,709**	$52,075	$ 18,577
Total income tax expense (benefits)	**27,829**	28,379	325
Pretax income	**85,538**	80,454	18,902
Statutory tax rate	**35%**	35%	35%
Federal income tax expense (benefit) at statutory rate	**29,938**	28,159	6,616
Depreciation related to difference in cost basis for tax purposes	**2,517**	2,678	2,691
Allowance for funds used during construction—equity	**(2,265)**	(574)	(601)
ITC amortization	**(1,788)**	(1,629)	(1,636)
Goodwill	**954**	844	506
Pension plan benefit	**338**	(945)	(3,684)
Research and development credit	**(2,097)**	—	—
Other—net	**232**	(154)	(217)
Provision for income taxes before effect of income tax settlements	**$27,829**	$28,379	$ 3,675
Effective tax rate before effects of income tax settlements	**32.5%**	35.3%	19.4%
Effects of income tax settlements	**—**	—	(3,350)
Provision for income taxes	**$27,829**	$28,379	$ 325
Effective tax rate	**32.5%**	35.3%	1.7%

As a large corporate taxpayer, the SPR consolidated group's tax returns are examined by the IRS on a regular basis. The IRS is currently conducting audits of SPPC for the years 1997-2004. During the first quarter of 2004, SPR reached tentative agreements with the IRS for certain matters. As a result of the tentative agreements, SPPC recognized tax benefits which increased net income by approximately $3.4 million in 2004. SPPC believes that it has adequately provided reasonable reserves for reasonable and foreseeable outcomes related to uncertain tax matters.

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

	2006	2005
Deferred income tax assets		
Net operating loss and credit carryforwards	**$ 6,233**	$ 6,127
Employee benefit plans	**39,191**	9,997
Customer advances	**11,149**	25,202
Gross-ups received on contributions in aid of construction and customer advances	**9,269**	7,438
Provision for contract termination	**200**	19,378
Other	**7,761**	6,658
Subtotal	**73,803**	74,800
Deferred income tax assets associated with regulatory matters		
Excess deferred income taxes	**9,852**	11,421
Unamortized investment tax credit	**10,772**	11,735
Subtotal	**20,624**	23,156
Total deferred income tax assets	**$ 94,427**	$ 97,956
Deferred income tax liabilities		
Excess of tax depreciation over book depreciation	**$195,203**	$211,645
Deferred energy	**21,540**	40,158
Regulatory assets	**41,346**	9,079
Other	**14,035**	9,193
Subtotal deferred tax liabilities	**272,124**	270,075
Deferred income tax liabilities associated with regulatory matters		
Tax benefits flowed through to customers	**109,699**	93,957
Total deferred income tax liability	**$381,823**	$364,032
Net deferred income tax liability	**$198,321**	$195,275
Net deferred income tax liability associated with regulatory matters	**89,075**	70,801
Total net deferred income tax liability	**$287,396**	$266,076

SPPC's balance sheet contains a net regulatory asset of $89.0 million at December 31, 2006 and $70.8 million at December 31, 2005. The regulatory asset consists of future revenue to be received from customers due to flow-through of the tax benefits of temporary differences and goodwill recognized from the merger of NPC and SPR. Offset against these amounts are future revenues to be refunded to customers (regulatory liabilities). The regulatory liabilities consist of temporary differences for liberalized depreciation at rates in excess of current rates and 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.

As reflected in SPPC's balance sheet (dollars in thousands):	2006	2005
Tax benefits flowed through to customers		
Related to property	**$ 50,998**	$ 43,959
Related to goodwill	**58,701**	49,998
Regulatory tax asset	**109,699**	93,957
Liberalized depreciation at rates in excess of current rates	**9,852**	11,421
Unamortized investment tax credits	**10,772**	11,735
Regulatory tax liability	**20,624**	23,156
Net regulatory tax asset	**$ 89,075**	$ 70,801

SPR and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on SPR's and each subsidiaries' respective taxable income or loss and investment tax credits as if each subsidiary filed a separate return. Per the Company's tax sharing agreement, SPPC owes SPR $9.1 million in current taxes payable.

The following table summarizes the tax NOL and credit carryforwards and associated carryforward periods for SPPC (dollars in thousands):

Type of Carryforward	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
Federal NOL	$5,184	$ —	$5,184	2020-2023
State NOL	1,049	—	1,049	2010-2013
Total	$6,233	$ —	$6,233	

At December 31, 2006, SPPC has gross federal and state net operating loss carryforwards of $14.8 million and $11.9 million, respectively.

Considering all positive and negative evidence regarding the utilization of SPPC's deferred tax assets, it has been determined that the company is more-likely-than-not to realize all recorded deferred tax assets and therefore no valuation allowance has been recorded as of December 31, 2006.

NOTE 11. 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 tables provide a reconciliation of benefit obligations, plan assets and the funded status of the plans. This reconciliation is based on a September 30 measurement date (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
CHANGE IN BENEFIT OBLIGATIONS				
Benefit obligation, beginning of year	**$625,451**	$519,785	**$179,184**	$162,013
Service cost	**23,033**	18,481	**3,533**	3,281
Interest cost	**36,627**	32,248	**10,283**	9,858
Plan participants' contributions	**—**	—	**1,445**	1,180
Actuarial loss (gain)	**(18,713)**	71,536	**(10,770)**	10,258
Gross benefits paid	**(20,960)**	(20,257)	**(11,998)**	(8,112)
Less: federal subsidy on benefits paid	**N/A**	N/A	**(515)**	—
Plan amendments	**(65)**	2,935	**—**	695
Acquisitions/divestitures	**—**	—	**—**	—
Special termination benefits	**—**	723	**—**	11
Curtailments	**—**	—	**—**	—
Settlements	**—**	—	**—**	—
Benefit obligation, end of year	**$645,373**	$625,451	**$171,162**	$179,184

The accumulated benefit obligation for pension benefits at the end of 2006 and 2005 was $526 million and $504 million, respectively.

The weighted average actuarial assumptions used to determine end of year benefit obligations were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
Discount rate	**6.00%**	5.75%	**6.00%**	5.75%
Rate of compensation increase	**4.50%**	4.50%	**N/A**	N/A

In 2006, for measurement purposes, the assumed annual rate of increase in the per capita cost of covered health care benefits was 8%, grading down to 5% in 2013.

In selecting an assumed discount rate for fiscal year 2006 pension cost, SPR considered the yield on high quality bonds as measured by Moody's Investors Service, Inc. (Moody's) Aa composite bond index. However, to select an assumed discount rate for fiscal year-end 2006 disclosures and for fiscal year 2006 pension cost, SPR's projected benefit payments were matched to the yield curve derived from a portfolio of over 500 high quality Aa bonds with yields within the 40th to 90th percentiles of these bond yields.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect:

Effect on the Postretirement Benefit Obligation	**2006**	2005
Effect of a 1-percentage point increase	**$ 18,823**	$ 21,237
Effect of a 1-percentage point decrease	**$(15,657)**	$ (17,410)

The following table shows the change in plan assets for 2006 and 2005. SPR contributions for the other postretirement benefits reflect benefit payments made by SPR (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
CHANGE IN PLAN ASSETS				
Fair value of plan assets, beginning of year	**$488,766**	$436,291	**$ 53,223**	$50,484
Adjustment to beginning of year value	**—**	—	**—**	(1,766)
Actual return on plan assets	**34,424**	55,706	**8,015**	386
Employer contributions	**32,329**	17,026	**12,550**	10,928
Plan participants' contributions	**—**	—	**1,445**	1,303
Gross benefits paid	**(20,960)**	(20,257)	**(11,998)**	(8,112)
Acquisitions	**—**	—	**—**	—
Special termination benefits	**—**	—	**—**	—
Settlements	**—**	—	**—**	—
Expenses paid	**(299)**	—		
Fair value of plan assets, end of year	**$534,260**	$488,766	**$ 63,235**	$53,223

The asset allocation for SPR's pension plans at the end of 2006 and 2005 and the target allocation for 2007, by asset category, follows. The fair value of plan assets for these plans is $534.2 million and $488.8 million at the end of 2006 and 2005, respectively. The asset values are determined using quoted market prices. The expected long-term rate of return on these plan assets was 8.25% in 2006 and 2005.

	Target Allocation Percentage of Plan Assets at Year End		
Asset Category	2007	**2006**	2005
Equity securities	60%	**60%**	60%
Debt securities	39	**39**	39
Other	1	**1**	1
Total	100%	**100%**	100%

The asset allocation for the other postretirement benefit plans at the end of 2006 and 2005 and target allocation for 2007, by asset category, follows. The fair value of plan assets for these plans is $63.2 million and $53.2 million at the end of 2006 and 2005, respectively. The asset values are determined using recorded closing sales on a national securities exchange. The expected long-term rate of return on these plan assets was 8.25% in 2006 and 2005.

	Target Allocation Percentage of Plan Assets at Year End		
Asset Category	2007	**2006**	2005
Equity securities	60%	**60%**	60%
Debt securities	39	**39**	39
Other	1	**1**	1
Total	100%	**100%**	100%

SPR's investment strategy is to ensure the safety of the principal of the assets and obtain asset performance to meet the continuing obligations of the plan. SPR strives to maintain a reasonable and prudent amount of risk and seeks to limit risk through diversification of assets. Also, SPR considers the ability of the plan to pay all benefit and expense obligations when due, and to control the costs of administering and managing the plan. SPR's investment guidelines prohibit investing the plan assets in real estate and SPR's own stock. Currently, the plan assets are invested in international and domestic equity securities, and fixed securities which include bonds.

The following table shows the funded status of each of the plans for 2006 and 2005 (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
FUNDED STATUS END OF YEAR:				
Fair value of plan assets	**$ 534,260**	$ 488,767	**$ 63,236**	$ 53,223
Benefit obligations	**$(645,373)**	$(625,451)	**$(172,192)**	$(179,184)
Funded status	**$(111,113)**	$(136,684)	**$(108,956)**	$(125,961)
Unrecognized net actuarial (gain)/loss	**N/A**	166,157	**N/A**	77,919
Unrecognized prior service (credit)/cost	**N/A**	14,543	**N/A**	1,228
Unrecognized net transition (asset)/obligation	**N/A**	—	**N/A**	6,405
Contribution between measurement date and fiscal year end	**368**	15,332	**—**	4,101
Amount recognized, end of year	**$(110,745)**	$ 59,348	**$(108,956)**	$ (36,308)

Amounts for pension and postretirement benefits recognized in the consolidated balance sheets consist of the following (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
AMOUNTS RECOGNIZED IN THE STATEMENT OF FINANCIAL POSITION CONSIST OF:				
Noncurrent asset	**$ —**	N/A	**$ —**	N/A
Current liability	**(1,482)**	N/A	**—**	N/A
Noncurrent liability	**(109,263)**	N/A	**108,956**	N/A
Prepaid benefit cost	**N/A**	$ 75,769	**N/A**	N/A
Accrued benefit cost	**N/A**	(16,421)	**N/A**	$(36,308)
Additional minimum liability	**N/A**	(7,950)	**N/A**	N/A
Intangible asset	**N/A**	15	**N/A**	N/A
Accumulated other comprehensive income	**N/A**	7,935	**N/A**	N/A
Net amount recognized	**$(110,745)**	$ 59,348	**$108,956**	$(36,308)

The following amounts would have been recognized in Accumulated Other Comprehensive Income, net of taxes, according to the provisions of SFAS 158, which the Company adopted in 2006. Since the Company is able to recover SFAS 87 and SFAS 106 expenses through rates, the amounts will be recorded as Other Regulatory Assets under the provisions of SFAS 71.

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
AMOUNTS RECOGNIZED AS OTHER REGULATORY ASSETS:				
Net actuarial (gain)/loss	**$101,674**	N/A	**$102,413**	N/A
Prior service (credit)/cost	**12,587**	N/A	**1,107**	N/A
Transition (asset)/obligation	**—**	N/A	**5,436**	N/A
	$114,261	N/A	**$108,956**	N/A

The estimated amounts that will be amortized from other regulatory assets into net periodic cost in 2007 are as follows:

	Pension Benefits	Other Postretirement Benefits
Actuarial (gain)/loss	$7,184	$3,259
Prior service (credit)/cost	1,629	122
Transition (asset)/obligation	—	969

At the end of 2006 and 2005, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets for pension plans with a projected benefit obligation, in excess of plan assets, and pension plans with an accumulated benefit obligation in excess of plan assets, were as follows (dollars in thousands):

	Projected Benefit Obligation Exceeds the Fair Value of Plan's Assets		Accumulated Benefit Obligation Exceeds the Fair Value of Plan's Assets	
	2006	2005	**2006**	2005
Projected benefit obligation, end of year	**$645,373**	$625,451	**$25,890**	$27,225
Accumulated benefit obligation, end of year	**—**	—	**23,768**	24,703
Fair value of plan assets, end of year	**534,260**	488,766	**—**	—

The accumulated postretirement benefit obligation exceeds plan assets for all of the company's other postretirement benefit plans.

The expected cash flows for the plans are as follows (dollars in thousands):

	Pension Benefits	Other Postretirement Benefits
COMPANY CONTRIBUTIONS		
2007 (expected)	$1,482	$12,465

		Other Postretirement Benefits	
	Pension Benefits	Gross	Expected Federal Subsidy
EXPECTED BENEFIT PAYMENT			
2007	$ 23,595	$ 9,209	$ 597
2008	24,903	9,812	670
2009	26,668	10,372	770
2010	28,684	11,028	853
2011	30,887	11,611	843
2012-2016	196,777	66,337	4,993

The above benefit payments are obligations of the indicated plan, and reflect payments which do not include employee contributions. The expected benefit payment information that reflects the employee obligation is almost exclusively paid from plan assets. A small portion of the pension benefit obligation is paid from the plan sponsor's assets.

The components of net periodic pension and other postretirement benefit costs for the consolidated companies SPPC and NPC are presented below (dollars in thousands):

Sierra Pacific Resources, Consolidated

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	**2006**	2005	2004
Service cost	**$ 23,033**	$ 18,481	$ 17,988	**$ 3,533**	$ 3,281	$ 3,058
Interest cost	**36,627**	32,248	30,273	**10,283**	9,858	9,258
Expected return on plan assets	**(40,729)**	(36,167)	(30,632)	**(4,919)**	(3,862)	(4,100)
Amortization of:						
Actuarial (gain)/loss	**9,778**	6,454	8,971	**4,614**	3,782	4,129
Prior service (credit)/cost	**1,892**	1,714	1,714	**122**	63	63
Transition (asset)/obligation	**—**	—	—	**969**	969	969
Curtailment (gain)/loss	**—**	—	—	**—**	—	—
Settlement (gain)/loss/special termination charges	**—**	723	—	**—**	11	—
Total net benefit cost	**$ 30,601**	$ 23,453	$ 28,314	**$14,602**	$14,102	$13,377

The average percentage of SPR net periodic costs capitalized during 2006, 2005 and 2004 was 35.5%, 34.1% and 32.1%, respectively.

Nevada Power Company

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	**2006**	2005	2004
Service cost	**$ 12,900**	$ 10,328	$ 9,770	**$ 1,052**	$ 887	$ 798
Interest cost	**17,466**	15,064	13,824	**2,105**	1,977	1,892
Expected return on plan assets	**(18,265)**	(16,025)	(12,564)	**(1,079)**	(832)	(885)
Amortization of:						
Actuarial (gain)/loss	**—**	—	—	**940**	758	844
Prior service (credit)/cost	**1,677**	1,499	1,499	**122**	63	63
Transition (asset)/obligation	**4,636**	2,995	4,069	**969**	969	969
Curtailment (gain)/loss	**—**	—	—	**—**	—	—
Settlement (gain)/loss/special termination charges	**—**	723	—	**—**	11	—
Total net benefit cost	**$ 18,414**	$ 14,584	$ 16,598	**$ 4,109**	$ 3,833	$ 3,681

The average percentage of NPC net periodic costs capitalized during 2006, 2005 and 2004 was 39.0%, 37.3% and 33.7%, respectively.

Sierra Pacific Power Company

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	**2006**	2005	2004
Service cost	**$ 8,989**	$ 7,470	$ 7,540	**$ 2,417**	$ 2,264	$ 2,135
Interest cost	**18,224**	16,526	15,820	**8,114**	7,793	7,284
Expected return on plan assets	**(21,617)**	(19,418)	(17,558)	**(3,715)**	(2,929)	(3,114)
Amortization of:						
Actuarial (gain)/loss	**—**	—	—	**3,646**	2,994	3,252
Prior service (credit)/cost	**212**	212	213	**—**	—	—
Transition (asset)/obligation	**4,880**	3,320	4,715	**—**	—	—
Curtailment (gain)/loss	**—**	—	—	**—**	—	—
Settlement (gain)/loss/special termination charges	**—**	—	—	**—**	—	—
Total net benefit cost	**$ 10,688**	$ 8,110	$ 10,730	**$10,462**	$10,122	$ 9,557

The average percentage of SPPC net periodic costs capitalized during 2006, 2005 and 2004 was 33.3%, 32.1%, and 31.6%, respectively.

The weighted average assumptions used to determine net periodic cost are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	**2006**	2005	2004
Discount rate	**5.75%**	6.10%	6.00%	**5.75%**	6.10%	6.00%
Expected return of plan assets	**8.25%**	8.25%	8.50%	**8.25%**	8.25%	8.50%
Rate of compensation increase	**4.50%**	4.50%	4.50%	**N/A**	N/A	N/A

For measurement purposes, a 6% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2006. The rate was assumed to remain at 6% in all future years.

The expected rate of return on plan assets was determined by considering a realistic projection of what assets can earn, given existing capital market conditions, historical equity and bond premiums over inflation, the effect of "normative" economic conditions that may differ from existing conditions, and projected rates of return on reinvested assets.

The expected long-term rate of return on plan assets is 8.25% in 2007.

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 effect:

One-Percentage Point Change	**2006**	2005	2004
Effect on total of service and interest cost components			
Effect of a 1-percentage point increase in health care trend	**$ 1,669**	$ 1,872	$ 1,845
Effect of a 1-percentage point decrease in health care trend	**$(1,360)**	$(1,503)	$(1,486)

There were no significant transactions between the plan and the employer or related parties during 2006, 2005 or 2004.

NOTE 12. STOCK COMPENSATION PLANS

At December 31, 2006, SPR 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 in May 2004, provides for the issuance of up to 7,750,000 of SPR's common shares to key employees through December 31, 2013. 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 2006, SPR issued nonqualified stock options, restricted shares and performance shares under the long-term incentive plan.

Nonqualified Stock Options

Elected officers and key employees specifically designated by a committee of the Board of Directors are eligible to be awarded nonqualified stock options (NQSO's) based on the guidelines in the plan. These grants are at 100% of the then current fair market value, and vest over different periods, as stated in the grant. These options have to be exercised within ten years of award, and no earlier than one year from the date of grant. At the time of grant, rights to dividend equivalents may also be awarded.

The total number of nonqualifying stock options granted to all employees in 2006 was 176,416, which were issued at an option price not less than market value at the date of grant. Of this amount, 144,304 will vest over three years from the grant date at one-third per year, 30,000 will vest one year from the date of grant, and the remaining 2,112 will vest only upon the restoration of the quarterly common stock dividend within five years of the date of grant; otherwise, these shares will expire unvested. The 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. The Committee also allows cashless exercises, subject to applicable securities law restrictions or other means consistent with the purpose of the plan and the applicable law.

A summary of the status of SPR's nonqualified stock option plan as of December 31, 2006, 2005 and 2004, and changes during the year is presented below:

	2006		2005		2004	
Nonqualified Stock Options	**Shares**	**Weighted Average Exercise Price**	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	**1,077,772**	**$14.38**	1,227,950	$15.91	1,371,869	$16.33
Granted	**176,416**	**$13.29**	169,036	$10.10	45,000	$ 7.29
Exercised	**55,000**	**$ 5.69**	28,000	$ 6.83	18,000	$ 5.39
Forfeited	**—**	**$ —**	291,214	$18.73	170,919	$17.41
Outstanding at end of year	**1,199,188**	**$14.66**	1,077,772	$14.38	1,227,950	$15.91
Intrinsic value of options exercised	**$ 571,190**	**—**	$ 147,240	—	$ 33.920	
Fair value of options vested	**$ 246,798**	**—**	$ 36,750	—	$ 111,011	
Options exercisable at year-end	**943,085**	**$15.25**	928,368	$15.07	1,215,450	$15.99
Weighted average grant date fair value of options granted:[1]						
Average of all grants for:						
2006	**$ 4.82**					
2005			$ 5.52			
2004					$ 4.96	

(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 2006, 2005 and 2004:

Year of Option Grant	Average Dividend Yield	Average Expected Volatility	Average Risk-Free Rate of Return	Average Expected Life
2006	0.00%	27.06%	4.51%	6 years
2005	0.00%	39.56%	2.32%	10 years
2004	0.00%	52.60%	4.79%	10 years

The following table summarizes information about nonqualified stock options outstanding at December 31, 2006:

		Options Outstanding		Options Exercisable	
Year of Grant	Weighted Average Exercise Price	Number Outstanding at 12/31/06	Remaining Contractual Life	Weighted Average Exercise Price	Number Vested and Exercisable at 12/31/06
1997	$ 19.97	3,188	<1 year	$ 19.97	3,188
1998	$ 24.93	15,840	1 years	$ 24.93	15,840
1999	$ 25.35	36,440	2 years	$ 25.35	36,440
2000	$ 16.00	400,000	2.6-3 years	$ 16.00	400,000
2001	$ 15.08	151,540	4-4.9 years	$ 15.08	151,540
2002	$ 14.05	241,360	5-5.9 years	$ 14.05	241,360
2004	$ 7.29	25,000	7.5 years	$ 7.29	25,000
2005	$ 10.10	149,404	8.2-8.4 years	$ 10.10	69,717
2006	$ 13.29	176,416	9.1 years	$ 13.29	—
Weighted Average Remaining Contractual Life			5.03 years		4.12 years
Intrinsic Value	$3,136,677			$1,975,871	

Dividend equivalents were not granted for any of these awards.

Performance Shares

In 2006, 2005 and 2004, SPR granted performance shares in the following numbers and initial values:

	2/7/2006	2/7/2005	1/16/2004
Shares granted	675,056	214,596	280,082
Value per share	$10.03	$9.58	$7.99

In 2006 and 2005, 172,446 and 171,676 shares of stock, respectively, were granted to plan participants; the actual number of shares earned by each participant is dependent upon SPR achieving certain financial goals over three-year performance periods. 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. Sierra Pacific Resources, at its sole discretion, may pay earned performance shares in the form of cash or in shares, or a combination thereof.

Also awarded in 2006 were 2,610 special grant shares to be earned only upon the restoration of both the NPC and SPPC investment grade credit status within three years of the date of grant.

In August 2006, upon the signing of an employment agreement for the Chief Executive Officer, a grant of 500,000 performance shares was issued according to the agreement. The grant requires the achievement of specific performance goals which were established in the agreement. The final determination and approval of the number of shares awarded is at the discretion of the Board of Directors and the Compensation Committee. In 2006, 65,000 shares were deemed to have been earned and were issued.

Also granted in 2005 were 42,920 special grant shares to be earned only upon the restoration of both the NPC and SPPC investment grade credit status within three years of the date of grant.

In 2004, SPR granted 280,082 shares of performance shares, which were subsequently reclassified as restricted stock. These grants are included in the discussion below of Restricted Stock.

SPR adopted SFAS 123R, "Share-Based Payment," in 2006, and according to the requirements set forth in that standard, recognized expense in 2006 related to performance shares. For purposes of determining 2006 expense, the compensation cost has been estimated using a lattice binomial pricing model with the following assumptions used for 2006:

Year	Average Dividend Yield	Average Expected Volatility	Average Risk-Free Rate of Return	Weighted Average Fair Value
2006	0.00%	39.03%	4.57%	$13.93

The total value of share-based liabilities paid in 2006, 2005 and 2004 were $1,447,300, $819,117 and $876,772, respectively. The total value of shares vested in 2006, 2005 and 2004 were $2,046,124, $807,942 and $0.00, respectively.

Restricted Stock Shares

In 2006, 5,643 shares of restricted stock were awarded at a grant price of $13.29 per share; this grant was fully vested on December 31, 2006 and the shares were issued in early 2007.

There were no restricted shares granted in 2005.

In 2004, SPR granted 280,082 performance shares, which were subsequently reclassified as restricted stock. Due to the achievement of certain performance goals established for this grant, the number of shares available under this grant was increased to 297,587. This grant vested on December 31, 2006, and 222,327 shares were issued in early 2007. The remaining 2004 grant of 3,700 restricted shares was issued at a grant price of $6.83 per share, and will vest over three years at one-third per year. In 2005, the remaining 2,467 shares available under this grant were forfeited.

In 2003, SPR granted 448,576 shares of restricted stock at an average grant price of $5.93 per share. Of the shares granted, 438,576 shares will vest over 4 years with one-third becoming available in each of the years ended December 31, 2004, 2005 and 2006. The remaining 10,000 shares will vest over three years at one-third per year. In 2006, according to the vesting schedule for each grant, 131,297 shares were issued under these grants.

A grant of 1,500 restricted shares was made in 2002, at a grant price of $7.35, vesting equally over 4 years. In 2006, 375 shares were issued according to the terms of this grant.

The total value of share-based liabilities paid in 2006, 2005 and 2004 were $1,500,321, $1,405,724 and $301,311, respectively. The total value of shares vested in 2006, 2005 and 2004 were $5,750,643, $1,596,657 and $1,406,496, respectively.

Employee Stock Purchase Plan

Upon the inception of SPR's employee stock purchase plan, SPR was authorized to issue up to an aggregate of 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 the lesser of 90% of the market value on the offering commencement date, or 100% of the market value on the offering exercise date. Employees can withdraw from the plan at any time prior to the exercise date. Under the plan, SPR sold 55,954, 53,162 and 77,511 shares to employees in 2006, 2005 and 2004, respectively.

SPR adopted SFAS 123R, "Share Based Payment," in 2006, and according to the requirements set forth in that standard, recognized expense in 2006 related to the employee stock purchase plan. For purposes of determining the 2006 expense and the 2005 and 2004 pro forma disclosures, 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 2006, 2005 and 2004, with an option life of six months:

Year	Average Dividend Yield	Average Expected Volatility	Average Risk-Free Rate of Return	Weighted Average Fair Value
2006	0.00%	19.73%	4.95%	$2.62
2005	0.00%	35.87%	2.23%	$2.65
2004	0.00%	52.60%	1.79%	$2.24

NOTE 13. COMMITMENTS AND CONTINGENCIES (SPR, NPC AND SPPC)

Purchased Power

The utilities have several contracts for long-term purchase of electric energy. Expiration of these contracts ranges from 2008 to 2027. Estimated future commitments under non-cancelable agreements as of December 31, 2006 were as follows (dollars in thousands):

	Purchased Power		
	NPC	SPPC	SPR[1]
2007	$ 310,988	$ 163,165	$ 462,402
2008	257,739	125,161	368,810
2009	239,361	98,028	323,215
2010	244,305	93,836	323,882
2011	242,671	95,231	323,541
Thereafter	2,868,242	1,308,566	3,925,708

(1) Amounts differ for SPR due to the elimination of certain intercompany contracts.

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 2007 to 2023. Estimated future commitments under non-cancelable agreements as of December 31, 2006 were as follows (dollars in thousands):

	Coal and Gas		
	NPC	SPPC	Total
2007	$202,156	$127,037	$329,193
2008	26,019	26,919	52,938
2009	13,261	24,964	15,138
2010	10,293	—	10,293
2011	—	—	—
Thereafter	—	—	—

	Transportation		
	NPC	SPPC	Total
2007	$ 48,045	$ 74,031	$122,076
2008	36,814	58,099	94,913
2009	36,814	48,428	85,242
2010	36,814	48,418	85,232
2011	34,438	48,418	82,856
Thereafter	183,550	361,358	544,908

Long-Term Service Agreements

NPC entered into a long-term service agreement in December 2005 to perform maintenance on generation units located at the Chuck Lenzie Generation Station. An additional long-term service agreement was entered into in January 2006 for maintenance of the generation units at the Silverhawk Generation Station. Future commitments under these agreements are as follows (dollars in thousands):

	Long-Term Service Agreements[1]		
	Lenzie	Silverhawk	Total
2007	$11,258	$ 4,721	$ 15,979
2008	11,258	2,609	13,867
2009	11,258	13,009	24,267
2010	11,258	10,779	22,037
2011	9,062	3,086	12,148
Thereafter	90,340	33,443	123,783

(1) Does not include equipment and services contracts related to the new peaking units at Clark Generating Station.

Leases

SPPC has an operating lease for its general offices. 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, NPC's and SPPC's estimated future minimum cash payments, including SPPC's headquarters building, under non-cancelable operating leases as of December 31, 2006, were as follows (dollars in thousands):

	Operating Leases		
	NPC	SPPC	Total
2007	$ 6,525	$10,635	$ 17,160
2008	7,146	10,297	17,443
2009	6,253	8,931	15,184
2010	5,161	7,587	12,748
2011	3,441	778	4,219
Thereafter	64,459	36,587	101,046

Environmental

NEVADA POWER COMPANY

REID GARDNER STATION In August 1999, the Nevada Department of Environmental Protection (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 following 10 years. This order also required NPC to submit a Site Characterization Plan to NDEP to ascertain impacts. This plan has been reviewed and approved by NDEP. In collaboration with NDEP, NPC has evaluated remediation requirements. In May 2004, NPC submitted a schedule of remediation actions to NDEP which included proposed dates for corrective action plans and/or suggested additional assessment plans for each specified area. Any future ponds will be double-lined with inter-liner leak detection in accordance with the NDEP Authorization to Discharge Permit issued October 2005.

Pond construction and lining costs to satisfy the NDEP order expended to date is approximately $36 million. Expenditures for 2007 through 2010 are projected to be approximately $10 million.

In August 2004, NDEP conducted a Facility Air Quality Operating Permit (Title V permit) inspection at the Reid Gardner Station. NDEP requested monitoring, recordkeeping and reporting items and information pertaining to the sources identified in the Title V permit. NPC complied with the request and any subsequent requests that followed. In September and October 2004, NPC met with NDEP to review the results of NDEP's inspection. NDEP informed NPC of possible non-compliance with some elements of its Title V permit, and in December 2004 issued Notices of Alleged Violation (NOAVs) relating to record-keeping, monitoring and other alleged administrative infractions. Discussions between NPC and NDEP ensued. In July 2005, NDEP issued new Notices of Alleged Violations (NOAVs). In part, these NOAVs represent reissuance of the previously issued NOAVs dated December 2, 2004 and address additional monitoring and reporting issues for the period September 2002 through December 2004. Additional NOAVs were issued concerning intermittent opacity emissions and the monitoring, record-keeping and reporting of such emissions. All NOAVs are subject to an administrative hearing before the Nevada State Environmental Commission and then to judicial review. In July 2005 NPC received a letter from the Environmental Protection Agency (EPA) requiring submittal of information relating to compliance of Reid Gardner Station with opacity emission limits and reporting requirements. NPC has responded to the EPA information request. In June 2006, the EPA issued a Finding and Notice of Violation (NOV).

NPC has progressed to the final draft stage of dialogue and settlement discussions with NDEP, EPA and the Department of Justice (DOJ) regarding the NOVs and additional environmental controls and equipment changes, environmental benefit projects, monetary penalties, and/or other measures that may be required to achieve a settlement of the alleged violations. Management has booked an estimated minimum liability with respect to these matters. Certain environmental controls and equipment changes needed to assure compliance with existing or modified regulations were submitted by NPC to the PUCN in NPC's 2006 Integrated Resource Plan (IRP) filing. These expenditures were approved by the PUCN in late 2006 and include equipment installation on the various units to control startup opacity and particulates and reduce operating opacity and oxides of nitrogen.

CLARK STATION In July 2000, NPC received a request from the EPA for information to determine the compliance of certain generation facilities at NPC's Clark Station with the applicable State Implementation Plan. In November 2000, NPC and the DAQEM 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. In October 2003, the EPA issued a violation regarding turbine blade upgrades, which occurred in July 1993. A conference between the EPA and NPC occurred in December 2003. NPC presented evidence on the nature and finding of the alleged violations. In March 2004, the EPA issued another request for information regarding the turbine blade upgrades, and NPC provided information responsive to this request in April and May 2004. NPC's position is that a violation did not occur. In May 2006, the EPA, by letter from the DOJ, notified NPC that it intends to initiate an enforcement action against NPC seeking unspecified civil penalties, together with injunctive relief, for alleged violations of the Prevention of Significant Deterioration requirements and Title V operating permit requirements of the Clean Air Act. NPC has entered into ongoing dialogue and settlement discussions with the EPA and DOJ regarding the alleged violations. Monetary penalties are not expected to be material and certain environmental controls and equipment changes needed to assure compliance with existing or modified regulations were submitted by NPC to the PUCN in January 2007 in NPC's Second Amendment to the 2006 IRP filing.

NEICO 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 has a reclamation estimate supported by a bond of approximately $5 million with the Utah Division of Oil and Gas Mining, which management believes is sufficient to cover reclamation costs. Management is continuing to evaluate various options including reclamation and sale.

SIERRA PACIFIC POWER COMPANY

PCB TREATMENT, INC. 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 PRP's formed a steering committee, which completed site investigations and along with the EPA determined that the Sites should be remediated by removing the buildings to the appropriate landfills. SPPC is a member of this steering committee. The cleanup has now been completed on both buildings and are pending inspection and signoff by EPA. The cleanup for the two buildings came in under budget; as such, SPPC does not expect any further obligations.

Litigation

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY

Enron Litigation

SETTLEMENT AGREEMENT On February 1, 2006, the Utilities completed the settlement of long-term, ongoing litigation involving Enron's market manipulation during the Western United States Energy Crisis and Enron's claims with respect to terminated purchase power contracts between Enron Power Marketing Inc. ("Enron") and the Utilities in accordance with the terms of the Settlement Agreement, entered into as of November 15, 2005 among the Utilities, Enron and other related Enron affiliates (the "Settlement Agreement"). The Settlement Agreement provided for the settlement and release of the ongoing litigation, regulatory proceedings, appellate proceedings, proofs of claim and other claims between Enron and the Utilities related to these matters. The Settlement Agreement received approval from the Enron Bankruptcy Court on December 15, 2005. The FERC's approval

of the Settlement Agreement was received on January 25, 2006, which triggered the mutual releases and discharges of all past, existing and future claims between the parties.

On January 26, 2006, upon final approval of the settlement with Enron, the Utilities paid Enron approximately $129 million from available cash resources. On January 27, 2006, the approximate $60 million cash held in escrow, plus interest, and NPC's General and Refunding Series H Bond of approximately $185.7 million and SPPC's General and Refunding Series E Bond of approximately $92.3 million were returned to the Utilities. As part of the settlement, NPC and SPPC were granted general unsecured claims (the "Unsecured Claims") in Class Six of Enron's Plan of Reorganization in the amount of $80.7 million and $45.8 million, respectively. On October 24, 2005, the Utilities purchased a put option from a major international banking institution that, if exercised, obligated that institution to purchase the Unsecured Claims (contingent upon allowance of the Unsecured Claims by the Bankruptcy Court), which ensured that the Utilities' net cash outlay to settle Enron's claim would be no higher than $89.9 million. On February 16, 2006, the Unsecured Claims were sold to a separate third party, resulting in a final net cash outlay which did not materially differ from the anticipated cash outlay.

NPC and SPPC filed applications with the PUCN in January 2007 and December 2006, respectively, to recover the amounts paid in connection with the Settlement Agreement, net of the proceeds from the sale of the Unsecured Claims. The Utilities cannot predict, whether, to what extent or upon what conditions the PUCN will approve recovery of these amounts. To the extent the Utilities are not permitted to recover these costs through rate filings, the amounts not permitted would be charged as a current operating expense. See Contract Termination Liabilities.

ENRON BANKRUPTCY COURT JUDGMENT On June 5, 2002, Enron filed suit against the Utilities in its bankruptcy proceeding before Enron Bankruptcy Court seeking liquidated damages of approximately $216 million from NPC and $93 million from SPPC asserting the Utilities had not provided adequate assurance of performance upon Enron's demand, which triggered Enron to terminate all power contracts with the Utilities under a Western Systems Power Pool Agreement (WSPPA). The Utilities denied liability on numerous grounds, including wrongful termination, deceit and fraud in the inducement, fraud, breach of contract, and unfair trade practices.

On September 26, 2003, the Bankruptcy Court entered summary judgment in favor of Enron (the "Judgment") for damages related to the termination of Enron's power supply agreements with the Utilities. The Judgment required NPC and SPPC to pay approximately $235 million and $103 million, respectively, to Enron for liquidated damages and pre-judgment interest for power not delivered by Enron under the power supply contracts terminated by Enron and approximately $17.7 million and $6.7 million, respectively, for power previously delivered to the Utilities. Based on the pre-judgment rate of 12%, NPC and SPPC recognized additional interest expense of $27.8 million and $12.4 million, respectively, in contract termination liabilities in the third quarter 2003. Also, NPC and SPPC recorded additional contract termination liabilities for liquidated damages of $6.6 million and $2.1 million, respectively, in the third quarter of 2003. The Bankruptcy Court's order provided that until paid, the amounts owed by the Utilities would accrue interest post-judgment at a rate of 1.21% per annum.

On November 6, 2003, the Enron Bankruptcy Court ruled to stay execution of the Judgment conditioned upon NPC and SPPC posting into escrow $235 million and $103 million, respectively, of General and Refunding Mortgage Bonds plus approximately $282 thousand by NPC for pre-judgment interest. On December 4, 2003, NPC and SPPC complied with the order of the Bankruptcy Court by issuing NPC's $235 million General and Refunding Mortgage Bond, Series H and SPPC's $103 million General and Refunding Mortgage Bond, Series E into escrow along with the required cash deposit for NPC. Additionally, the Utilities were ordered to place into escrow $35 million, approximately $24 million and $11 million for NPC and SPPC, respectively, within 90 days from the date of the order, which would lower the principal amount of General and Refunding Mortgage Bonds held in escrow by a like amount. The Utilities made the payments as ordered on February 10, 2004. On April 16, 2004, NPC agreed to post an additional cash sum of $25 million in escrow, which lowered the principal amount of NPC's General and Refunding Mortgage Bond, Series H, by a like amount, as part of an agreement with Enron in which Enron agreed not to request any additional collateral from NPC or SPPC during the pendency of the Utilities' appeal of the Judgment to the District Court.

On October 10, 2004, in response to our appeal of the Bankruptcy Court Judgment, the U.S. District Court for the Southern District of New York held that the pre-judgment interest should have been calculated at the present value rate, rather than at the rate of 1% per month used by the Bankruptcy Court. Based on this decision, the Utilities reversed the accrued interest included in contract termination liabilities by approximately $40 million for the year ended 2004.

NEVADA POWER COMPANY

MORGAN STANLEY PROCEEDINGS On November 29, 2005, SPR and NPC entered into a settlement agreement with Morgan Stanley Capital Group, Inc. (MSCG) resolving the litigation in the United States District Court, District of Nevada concerning various power supply contracts between NPC and MSCG that had been terminated by MSCG in April 2002 and the FERC 206 Complaint against MSCG and the related appeal described above. Under the terms of the settlement agreement, NPC paid $17.5 million to MSCG and the parties dismissed the litigation concerning terminated power contracts between them and the FERC 206 proceedings as they relate to MSCG.

EL PASO MERCHANT ENERGY On January 19, 2006, NPC and EPME entered into a Settlement Agreement in resolution of their termination claims and counterclaims under the WSPPA in the Federal District Court, District of Nevada. Parties further agreed to withdraw, as to EPME, the appeal currently pending in the Ninth Circuit (FERC 206 Appeal) and to dismiss, as to EPME, any complaints made at FERC related to such appeal. NPC agreed to pay EPME $19 million. NPC and EPME executed a final written settlement agreement implementing the terms of this settlement on February 13, 2006.

NEVADA POWER COMPANY 2001 DEFERRED ENERGY CASE On November 30, 2001, NPC made a deferred energy filing with the PUCN seeking repayment 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 rate to repay 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 Order on the 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. NPC and the Bureau of Consumer Protection (BCP) both sought individual review of the PUCN Order in the First District Court of Nevada. The District Court affirmed the PUCN's decision. Both NPC and the BCP filed Notices of Appeal with the Nevada Supreme Court.

On July 20, 2006, the Nevada Supreme Court ruled that NPC is allowed to recover approximately $180 million of deferred energy and directed the District Court to remand the issue back to the PUCN to determine the rate schedule that will be used to recover this amount. In all other respects, the Nevada Supreme Court affirmed the District Court's decision on the PUCN disallowance. In the third quarter of 2006, as a result of the Nevada Supreme Court decision, NPC recorded approximately $180 million, before tax, of the previously disallowed deferred energy costs in its Consolidated Income Statements as Reinstatement of Deferred Energy.

In November 2006, the PUCN established a new docket (PUCN Docket No. 06-11029) for the purpose of determining the appropriate rate schedule for recovering approximately $180 million of deferred energy.

In February 2007, NPC entered into a stipulation where NPC shall be authorized to recover in rates $189.9 million over ten years beginning on June 1, 2007, with no additional carrying charges. This stipulation is expressly conditioned upon the PUCN's acceptance of the concurrently filed stipulation related to the Western Energy Crisis, discussed in Note 3, Regulatory Actions. If the PUCN does not accept both stipulations, this stipulation shall be deemed withdrawn, and all parties will retain all rights to litigate. The PUCN has yet to issue an order on the stipulation.

PEABODY WESTERN COAL COMPANY NPC owns an 11%, 255 MW interest in the Navajo Generating Station (Navajo) which includes three coal-fired electrical generating units and is located in Northern Arizona. Other participants in Navajo are the Salt River Project (Salt River), Arizona Public Service Company, Los Angeles Department of Water and Power, and Tucson Electric Power Company (together, the Joint Owners).

On October 15, 2004, coal supplier Peabody Western Coal Co. (Peabody) filed a complaint against the Joint Owners in Missouri State Court in St. Louis, seeking reimbursement of royalties and other costs and damages for alleged breach of the coal supply agreement for the Navajo plant. In January 2005, the Joint Owners were served and operating agent, Salt River, has engaged counsel and is defending the suit on behalf of the Joint Owners. NPC believes Peabody's claims are without merit and intends to contest these.

On February 10, 2005, the Joint Owners filed Notice of Removal of the complaint to the U. S. District Court, Eastern District of Missouri. On March 17, 2005, Peabody filed a motion to remand the case back to state court in St. Louis, Missouri. Joint Owners have filed a motion to dismiss the complaint for lack of jurisdiction. On May 30, 2006, the Federal District Court granted Peabody's motion and remanded the case back to state court. On June 29, 2006, Joint Owners filed a new motion to dismiss with the Missouri state court and requested a stay of the discovery proceedings pending the ruling on the new motion. On September 21, 2006, the Missouri state court heard oral arguments on the motion to dismiss. Parties are in the process of completing briefing on the motions. A decision is not expected until early 2007. Several discovery motions remain pending. NPC is unable to predict the outcome of the decisions.

SIERRA PACIFIC POWER COMPANY

FARAD DAM SPPC owns 4 hydro generating plants (10.3 MW capacity) located in California that were to be included in the sale of SPPC's water business for $8 million to the Truckee Meadows Water Authority (TMWA) in June 2001. The contract with TMWA requires that SPPC transfer the hydro assets in working condition. However, one of the four hydro generating plants, Farad 2.8 MW, has been out of service since the summer of 1996 due to a collapsed flume. While planning the reconstruction, a flood on the Truckee River in January 1997 destroyed the diversion dam. The current estimate to rebuild the diversion dam, if management decides to proceed, is approximately $20 million.

SPPC filed a claim with the insurers Hartford Steam Boiler Inspection and Insurance Co. and Zurich-American Insurance Company (Insurers) for the flume and dam. In December 2003, SPPC sued the Insurers in the U.S. District Court for the District of Nevada on a coverage dispute relating to potential rebuild costs. In May 2005, Insurers filed a motion for summary judgment on the coverage issue, which has been denied. In October 2005, Insurers filed another (partial) summary judgment motion with respect to coverage, which the court also denied. On June 16, 2006, Insurers filed new summary judgment motions, which SPPC opposed. Management believes that it has a valid insurance claim and is likely to recover the costs to rebuild the dam through the courts or from other sources.

Management has not recorded a loss contingency for this matter, as the loss, if any, cannot be estimated at this time.

PIÑON PINE In its 2003 General Rate Case, SPPC sought recovery of its unreimbursed costs associated with the Piñon Pine Coal Gasification Demonstration Project (the "Project"). The Project represented experimental technology tested pursuant to a Department of Energy (DOE) Clean Coal Technology initiative. Under the terms of the Project agreement, SPPC and DOE agreed to each fund 50% of construction costs of the Project. SPPC's participation in the Project had received PUCN approval as part of SPPC's 1993 integrated electric resource plan. While the conventional portion of the plant, a gas-fired combined-cycle unit, was installed and performed as planned, the coal gasification unit never became fully operational. After numerous attempts to re-engineer the coal gasifier, the technology was determined to be unworkable. In its order in May 2004, the PUCN disallowed $43 million of unreimbursed costs associated with the Project. SPPC filed a Petition for Judicial Review with the Second Judicial District Court of Nevada (District Court) in June 2004 (CV04-01434). In January 2006, the District Court vacated the PUCN's disallowance in SPPC's 2003 General Rate Case and remanded the case back to the PUCN for further review as to whether the costs were justly and reasonably incurred (Order). On March 27, 2006, the PUCN appealed the Order to the Nevada Supreme Court (the "Supreme Court") and filed a motion to stay the Order pending the appeal to the Supreme Court. On June 12, 2006, the District Court granted PUCN's motion to stay the Order. The Supreme Court dismissed the appeal in September 2006. Requests for rehearing were denied in late December 2006, and on January 18, 2007 the matter was remitted back to the District Court, which, consistent with its January 25, 2006 order, will remand the matter back to the PUCN for further review. A procedural schedule for this review has not yet been established.

Other Legal Matters

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, in the opinion of management, is expected to have a significant impact on their financial positions, results of operations or cash flows.

Contract Termination Liabilities

At December 31, 2006, pursuant to the deferred energy accounting provisions of AB 369, included in NPC and SPPC deferred energy balances were approximately $80.1 million and $16.3 million of charges, respectively, for recovery in rates in future periods associated with the terminated power supply contracts. In January 2007, NPC filed an application to recover $83.6 million in deferred legal and settlement costs incurred to resolve claims arising for the Western Energy Crisis. In February 2007, NPC entered into a stipulation, with the parties to the case, to recover the $83.6 million plus carrying charges over a 3-year period beginning June 1, 2007. This stipulation is expressly conditioned upon the PUCN's acceptance of the concurrently filed stipulation related to NPC's 2001 Deferred Energy Case, discussed in Note 3, Regulatory Actions. If the PUCN does not accept both stipulations, this stipulation shall be deemed withdrawn, and all parties will retain all rights to litigate. The PUCN has yet to issue an order on the stipulation.

In December 2006, SPPC filed an application to recover $22.6 million in deferred legal and settlement costs incurred to resolve claims arising for the Western Energy Crisis. To the extent that the Utilities are not permitted to recover any portion of these costs, the disallowed amounts would be charged to current operating expense. In February 2007, SPPC entered into a stipulation where SPPC replaces its request to implement rates on July 1, 2007 with a request to establish a regulatory asset to recover the costs. SPPC further requests authority to recover carrying charges on the regulatory asset. SPPC may request authority to begin recovering the regulatory asset established by the PUCN in a future application to change rates. The parties to the stipulation have requested that the PUCN issue an order by September 30, 2007. A significant disallowance of these costs by the PUCN could have a material effect on the future financial position, results of operations, and cash flows of SPR, NPC and SPPC.

Regulatory Contingencies

NEVADA POWER COMPANY

MOHAVE GENERATION STATION (MOHAVE) In 2005, NPC's ownership interest in Mohave comprised approximately 10% of NPC's peak generation capacity. Southern California Edison (SCE) is the operating partner of Mohave and NPC owns approximately 14% of the facility.

When operating, Mohave obtained 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 was 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.

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. In 1999, the plant owners and plaintiffs filed a settlement with the court, which resulted in a consent decree, approved by the court in November 1999. The consent decree established emission limits for sulfur dioxide and opacity and required installation of air pollution controls for sulfur dioxide, nitrogen oxides and particulate matter. Pursuant to the decree, Mohave Units 1 and 2 ceased operations as of January 2006 as the new emission limits were not met. Due to the lack of resolution regarding continual availability of the coal and water supply with the Tribes, the Owners did not proceed with the Consent Decree.

In December 2005, the Owners of the Mohave plant suspended operation pending resolution of these issues. However, in June 2006, majority stake holder SCE announced it would no longer participate in the efforts to return the plant to service. As a result, NPC decided it is not economically feasible to continue its participation in the project. In September 2006, Salt River's co-tenancy agreement and the operating agreement between the Owners expired in July 2006. The Owners are negotiating an extension of both agreements including a process that addresses how Owners may sell or assign their right, title, interest and obligations in Mohave.

In NPC's 2003 General Rate Case, the PUCN ordered the use of a regulatory asset to accumulate the costs and savings associated with Mohave in the event of its shutdown with recovery of any accumulated costs in a future rate case proceeding. NPC continues to recover the cost of Mohave in rates, as such, associated savings are currently recorded as a reduction in Electric Operating Revenues—Other. NPC continues to accumulate all costs and savings associated with the shut-down of Mohave, including unrecovered plant costs, in Other Regulatory Assets which has a balance of $17.8 million as of December 31, 2006. In its General Rate Case, NPC requested further clarification on the regulatory treatment of Mohave. In the event any portion of Mohave is disallowed, NPC will have to evaluate the asset for impairment.

NOTE 14. COMMON STOCK AND OTHER PAID-IN CAPITAL

RIGHTS AGREEMENT In December 2005, the Board of Directors of SPR (the Board) voted to amend the Rights Agreement, dated as of February 2001 (as amended and restated, the "Rights Agreement"), between SPR and Wells Fargo Bank Minnesota, N.A., to accelerate the final expiration date of the rights ("Rights") issued thereunder to December 2005, and to terminate the Rights Agreement upon the expiration of the Rights. The Board also adopted a policy governing future entry into a shareholder rights agreement or similar agreement (a "shareholder rights plan"). SPR's policy is to seek shareholder approval prior to the adoption of a shareholder rights plan, unless the Board, in the exercise of its fiduciary duties and with the concurrence of a majority of its independent members, determines that, under the circumstances existing at the time, it is in the best interest of SPR's shareholders to adopt a shareholder rights plan without first obtaining shareholder approval. If a shareholder rights plan is adopted without prior shareholder approval, the plan must provide that is shall expire, unless ratified by shareholders, within one year of adoption.

EMPLOYEE STOCK OWNERSHIP PLANS As of December 31, 2006, 8,279,478 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 (LTIP).

The 2005 LTIP for officers and key employees allows for the issuance of SPR's common shares through December 2013, which can be earned and issued prior to December 2013. 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, bonus stock and cash.

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. In addition, in 1996 SPR 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.

NON-EMPLOYEE DIRECTOR STOCK The annual retainer for non-employee directors is $57,000, and the minimum amount to be paid in SPR stock is $35,000 per director. During 2006, 2005 and 2004, SPR granted the following total shares and related compensation to directors in SPR stock, respectively: 30,733, 31,631 and 18,740 shares, and $154,000, $176,000 and $140,000.

CONVERTIBLE NOTES ISSUANCE In February 2003, SPR issued and sold $300 million of its 7.25% Convertible Notes due 2010. In August 2003, SPR obtained shareholder approval to issue additional shares of SPR's common stock in lieu of paying the cash payment component upon conversion of the Convertible Notes. In August 2005, SPR announced an offer to pay a cash premium to induce holders to convert their 7.25% Notes to shares of SPR common stock. The conversion offer was accepted by 100% of the holders. In September 2005, 65,749,096 shares of common stock, plus cash in lieu of fractional shares, were issued to the holders in exchange for the 7.25% Notes. For additional information regarding these Convertible Notes, see Note 6, Long-Term Debt.

In September 2005, 65,749,096 shares of common stock, plus cash in lieu of fractional shares and an aggregate of $54 million in cash consideration were paid to the holders in exchange for the Convertible Notes. In accordance with SFAS No. 84, "Induced Conversion of Convertible Debt," the $54 million cash payment was expensed during the third quarter of 2005.

STOCK EXCHANGE TRANSACTIONS In November 2005, SPR issued 17,344,183 shares of common stock, along with cash in lieu of fractional shares in connection with its PIES. Each PIES consisted of a forward stock purchase contract and a senior unsecured note issued by SPR.

In February 2003, SPR acquired 2,095,650 of PIES including approximately $104.8 million of 7.93% Senior Notes that were a component of the PIES, in exchange for 13,662,393 shares of its common stock.

In May 2005, SPR exchanged approximately 41% of the PIES for newly issued PIES ("New PIES") and issued, as a component of the New PIES, $99,142,000 aggregate principal amount of 7.93% Senior Notes, due 2007. These Senior Notes replaced the notes associated with the PIES. SPR successfully remarketed these notes in June 2005 at an interest rate of 7.803%.

In August 2005, the remaining $141,076,000 aggregate principal amount of its 7.93% Senior Notes associated with the PIES were remarketed. In August 2005, SPR used a portion of the proceeds from the $225 million 6.75% Senior Notes (see Note 6, Long-Term Debt) to purchase all of the 7.93% Senior Notes.

In November 2005, the purchase contract settlement date for the PIES and New PIES, 3.6101 shares per forward purchase contract were exchanged for a total of 17,344,183 shares of common stock issued to holder of the PIES and New PIES.

INCREASED AUTHORIZED SHARES In May 2006, SPR's shareholders approved an amendment to SPR's Restated Articles of Incorporation to increase the number of authorized shares of SPR common stock by 100,000,000 shares for a total amount of 350,000,000 authorized shares.

COMMON STOCK OFFERING In August 2006, SPR issued 20 million shares of its $1 par value common stock. Net proceeds from the issuance were $280.6 million. In August 2006, SPR contributed capital to NPC of approximately $200 million. NPC used the proceeds to repay indebtedness under its revolving credit facility.

In December 2006, SPR contributed capital to SPPC of approximately $75 million. SPPC used the proceeds to repay indebtedness under its revolving credit facility and general corporate purposes. SPR has invested the remaining proceeds in highly liquid short-term investments pending their use for general corporate purposes. As of December 31, 2006, SPR has 350 million shares of common stock authorized and 221.0 million shares of common stock issued and outstanding.

NOTE 15. PREFERRED STOCK

SIERRA PACIFIC POWER COMPANY

Preferred Stock

In June 2006, SPPC redeemed $50 million of its Class A, Series 1 Preferred Stock. Two million shares of stock were redeemed at a redemption price per share of $25.683, plus accrued dividends at the redemption date of $0.4875 per share.

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

On November 1, 2006, Sierra Pacific Power Company filed its restated articles of incorporation with the Nevada Secretary of State. SPPC also filed a withdrawal of the certificate of designation for its previously issued but no longer outstanding series of preferred stock.

The restated articles authorize the issuance of (i) twenty million (20,000,000) shares of common stock with a par value of $3.75 per share; and (ii) ten million (10,000,000) shares of preferred stock with no par value per share. Currently, all of SPPC's one thousand (1,000) shares of common stock outstanding are held by SPR.

Under the restated articles, preferred stock may be issued from time to time in one or more series in such amounts and with such terms and conditions as may be determined by the Board of Directors.

The restated articles limit the liability of directors and officers to the fullest extent permitted by applicable law. The restated articles may be amended or altered by a vote of the holders of a majority of SPPC's common stock then issued, outstanding and entitled to vote. SPPC may sell its assets upon the affirmative vote of a majority of the Board of Directors.

The restated articles eliminate the restrictive covenants that were previously contained in SPPC's articles of incorporation, including a limitation on the amount of dividends that may be paid on SPPC's common stock and a limitation on the amount of secured debt that may be issued by SPPC.

The following table indicates the dollar amount and number of shares of SPPC preferred stock outstanding at December 31 of each year (dollars in thousands).

	Amount		Shares Outstanding	
Preferred Stock	**2006**	2005	**2006**	2005
Not subject to mandatory redemption SPPC Class A Series 1	**$ —**	$50,000	**—**	2,000,000
Total Preferred Stock	**$ —**	$50,000	**—**	2,000,000

NOTE 16. EARNINGS PER SHARE (EPS) (SPR)

The difference, if any, between basic EPS and diluted EPS is due to potentially dilutive common shares resulting from stock options, the employee stock purchase plan, performance and restricted stock plans and the non-employee director stock plan.

For the year ended December 2004, SPR had outstanding $300 million in 7.25% Convertible Notes due 2010 that were entitled to receive (non-cumulative) dividend payments on a 1:1 basis for dividends paid to common shareholders without exercising the conversion option. These Convertible Notes met the criteria of a participating security in the calculation basic EPS, and were convertible at the option of the holders into 65,749,110 common shares.

Emerging Issues Task Force, Participating Securities and the Two-Class Method under FASB Statement No. 128, (EITF 03-6), requires companies to use the "two-class" method to calculate basic EPS, and the "if-converted" method to calculate diluted EPS if the result was dilutive. In September 2005, SPR issued approximately 65.7 million shares of common stock in connection with the early conversion of the 7.25% Convertible Notes. The weighted average shares outstanding up to the date of conversion are shown separately for the year ending December 2005.

In November 2005 the conversion of SPR's PIES resulted in the issuance of 17.3 million shares. For the year ended December 2005, these shares are included in the denominator on a weighted average basis.

The following table outlines the calculation for earnings per share (EPS):

Year ended December 31,	**2006**	2005	2004
BASIC EPS			
NUMERATOR ($000)			
Income from continuing operations	**$ 279,792**	$ 86,137	$ 30,842
Gain on sale of discontinued operations	**$ —**	$ —	$ 1,629
Net income applicable to common stock	**$ 277,451**	$ 62,198	$ 18,310
Net income applicable to convertible notes	**$ —**	$ 20,039	$ 10,261
Net income used for basic calculation	**$ 277,451**	$ 82,237	$ 28,571
DENOMINATOR			
Weighted average number of common shares outstanding	**208,531,134**	140,334,552	117,331,365
Shares from conversion of notes	**—**	45,213,762	65,749,110
	208,531,134	185,548,314	183,080,475
PER SHARE AMOUNTS			
Income from continuing operations	**$ 1.34**	$ 0.46	$ 0.17
Gain on sale of discontinued operations	**$ —**	$ —	$ 0.01
Net income applicable to common stock	**$ 1.33**	$ 0.44	$ 0.16
Net income applicable to convertible notes	**$ —**	$ 0.44	$ 0.16
DILUTED EPS			
NUMERATOR ($000)			
Income from continuing operations	**$ 279,792**	$ 86,137	$ 30,842
Gain on sale of discontinued operations	**$ —**	$ —	$ 1,629
Net income applicable to common stock	**$ 277,451**	$ 82,237	$ 28,571
DENOMINATOR[1]			
Weighted average number of shares outstanding before dilution	**208,531,134**	140,334,552	117,331,365
Stock options	**91,119**	47,255	24,949
Executive long-term incentive plan—restricted	**113,456**	187,810	242,679
Non-employee director stock plan	**30,754**	21,193	15,028
Employee stock purchase plan	**3,345**	3,925	15,028
Performance shares	**251,088**	124,007	22,144
Convertible stock	**—**	45,213,762	65,749,110
	209,020,896	185,932,504	183,400,303
PER SHARE AMOUNTS			
Income from continuing operations	**$ 1.34**	$ 0.46	$ 0.17
Gain on sale of discontinued operations	**$ —**	$ —	$ 0.01
Net income applicable to common stock	**$ 1.33**	$ 0.44	$ 0.16

(1) The denominator does not include stock equivalents resulting from the options issued under the nonqualified stock option plan for the years ended December 31, 2006, 2005 and 2004, due to conversion prices being higher than market prices for all periods. Under the nonqualified stock option plan for the years ended December 31, 2006, 2005 and 2004, 932,946, 917,623 and 1,146,728 shares, respectively, would be included. The denominator also does not include stock equivalents resulting from the conversion of the Corporate PIES for the year ended December 31, 2004. The amounts that would be included in the calculation if the conversion price were met would be 17.3 million shares.

NOTE 17. DISCONTINUED OPERATIONS AND DISPOSAL AND IMPAIRMENT OF LONG-LIVED ASSETS

Effective January 2002, SPR, NPC and SPPC adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which addresses financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 requires a component of an entity that either has been disposed of or is classified as held for sale to be reported as discontinued operations if certain conditions are met. Further, SFAS No. 144 requires that assets to be held and used be tested for recoverability whenever events or circumstances indicate that its carrying amount may not be recoverable.

Sierra Pacific Communications

SPC was formed as a Nevada corporation in 1999 to identify and develop business opportunities in telecommunications services and infrastructure. SPC's business activities have included the development of a fiber optic system extending between Salt Lake City, Utah, and Sacramento, California, (Long Haul Assets) and the development of Metro Area Networks (MAN) in Las Vegas and Reno, Nevada.

In 2004, SPC disposed of their MAN assets and recognized a gain on sale of assets of approximately $2.5 million (pretax) in connection with the sale of the MAN assets. SPC retained possession of one duct and associated occupancy rights in the Long Haul System allowing SPC to complete the transfer and sale of this duct, which was negotiated under a 2002 contract with Qwest Communications (Qwest) for $20 million. In 2004, in accordance with Statement of Financial Accounting Standards 144 (SFAS 144), "Accounting for the Disposition or Impairment of Long-Lived Assets," SPR reported the remaining Long Haul System as discontinued operations. However, due to certain legal issues, SPR was delayed in consummating the sale of the Long Haul System to Qwest. In January 2007, SPC agreed to dismiss pending arbitration against Qwest. As part of the Settlement Agreement, Qwest agreed to execute a quit claim deed disclaiming any further interest in the Long Haul System. In accordance with SFAS 144, if at any time the criteria for classifying assets as held for sale are no longer met, a long-lived asset classified as held for sale shall be reclassified as held and used. As of December 31, 2006, SPC assets associated with the Long Haul were reclassified for all periods presented from assets held for sale in discontinued operations to assets held and used.

NOTE 18. GOODWILL AND OTHER MERGER COSTS

In March 2004, the PUCN issued a decision on NPC's General Rate Case that included the recovery of goodwill and other merger costs allocated to NPC resulting from the merger of SPR and NPC in 1999. In its decision, the PUCN affirmed that NPC demonstrated merger savings exceeded merger costs, the requisite requirement for recovery of goodwill and merger costs through rates charged to NPC customers. The PUCN decision permits NPC to recover approximately $4 million per year for two years beginning April 2004, based on a forty-year amortization of NPC's total goodwill. The amount recovered over those two years reflected a reduction of 20% from the amounts sought by NPC, or approximately $1 million per year, due to customer satisfaction survey results that the PUCN determined required improvement. As a result of the PUCN decision, goodwill of approximately $198 million was reclassified as a regulatory asset and then transferred from the financial statements of SPR to the financial statements of NPC as of March 31, 2004.

Furthermore, the PUCN decision requires NPC to again demonstrate in its next general rate application that merger savings continue during the test period in that case. The PUCN's order in that case will determine if any further documentation of merger savings is required in the future. In November 2006, NPC filed its GRC, requesting 100% recovery of the amortization amount. Management expects that it will be able to demonstrate continued savings as a result of the merger as well as satisfactory customer survey results.

In May 2004, the PUCN approved a settlement agreement entered into by SPPC, the staff of the PUCN and other interveners in connection with SPPC's 2003 General Rate Case that permits SPPC recovery of goodwill and other merger costs assigned to SPPC's electric business. SPPC is permitted to recover approximately $2.4 million per year for two years beginning June 2004, based on a forty-year amortization of goodwill costs. As a result of the PUCN decision, goodwill of approximately $96 million was reclassified to a regulatory asset and transferred from the financial statements of SPR to the financial statements of SPPC as of June 30, 2004.

Similar to the decision reached in NPC's rate case described above, in order to continue to recover goodwill costs, SPPC was required to again demonstrate in its next general rate application filed October 2005, that merger savings continued during the test period in that case. In April 2006, the PUCN concluded that SPPC shall be allowed full recovery of its unamortized merger costs thereby ending the merger-related regulatory filings. See Note 3, Regulatory Actions for more information regarding the NPC and SPPC general rate decisions.

SFAS No. 142 provides that an impairment loss is to 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 developed for NPC's and SPPC's electric business and for SPR's unregulated businesses to determine the fair value of each reporting unit as of March 31, 2004. As part of the impairment testing analysis, management revised certain underlying assumptions utilized in previously performed preliminary analyses, that included, revised cash flow forecasts, an increase in the discount rate applied to future cash flows and other assumptions related to the outcomes of NPC's and SPPC's General Rate Cases. As a result of this impairment testing, SPR recorded a goodwill impairment charge related to NPC's and SPPC's electric reporting units of approximately $2 million and $10 million as a charge to other operating expenses in SPR's, NPC's and SPPC's Consolidated Statements of Income for the quarter ended March 31, 2004. Goodwill assigned to SPR's unregulated businesses was determined not to be impaired.

In April 2006, the PUCN issued a decision on SPPC's General Rate Case for the gas distribution business that included the recovery of goodwill and other merger costs allocated to SPPC resulting from the merger of SPR and NPC in 1999. In its decision, the PUCN affirmed that SPPC demonstrated merger savings exceeded merger costs, the requisite requirement for recovery of goodwill and merger costs. As a result of the PUCN decision, goodwill of approximately $18.9 million was reclassified as a regulatory asset and transferred from the financial statements of SPR to the financial statements of SPPC as of June 30, 2006. See Note 3 of the Notes to Consolidated Financial Statements, Regulatory Actions for more information regarding the SPPC general rate decision.

Approximately $4 million of goodwill was assigned to SPR's unregulated operations, (TGPC and LOS) as of March 2006. In December 2006, TGPC sold its investment in TGTC. As a result of the sale, the $3.5 million of goodwill assigned to TGPC goodwill was allocated against the gain on the sale of the investment. Reference Note 4, Investments in Subsidiaries and Other Property, for further discussion regarding the sale of TGTC. As of December 31, 2006, goodwill of approximately $500 thousand is allocated to SPR's unregulated operation of LOS.

NOTE 19. 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.

Sierra Pacific Resources

2006 Quarter Ended	**Revised March**	**Revised June**	**Revised September**	**December**
Operating revenues	**$707,056**	**$821,919**	**$1,081,967**	**$745,008**
Operating income[6]	**$ 59,577**	**$ 90,683**	**$ 283,793[1]**	**$ 54,744**
Income from continuing operation[5]	**$ 2,217**	**$ 29,202**	**$ 222,246**	**$ 26,127[2]**
Net income applicable to common stock	**$ 1,242**	**$ 27,836**	**$ 222,246**	**$ 26,127**
Income per share—basic and diluted:				
From continuing operations	**$ 0.01**	**$ 0.15**	**$ 1.05**	**$ 0.12**
Net income applicable to common stock	**$ 0.01**	**$ 0.14**	**$ 1.05**	**$ 0.12**

2005 Quarter Ended	Revised March	Revised June	Revised September	December
Operating revenues	$ 648,996	$ 701,038	$ 959,126	$ 721,082
Operating income	$ 58,953	$ 80,894	$ 162,750	$ 56,081
Income from continuing operations[6]	$ (8,511)	$ 10,026	$ 61,993[3]	$ 22,629[4]
Net income (loss) applicable to common stock	$ (9,486)	$ 9,051	$ 61,018	$ 21,654
Income (loss) per share—basic and diluted:				
From continuing operations	$ (0.07)	$ 0.05	$ 0.34	$ 0.12
Net income (loss) applicable to common stock	$ (0.08)	$ 0.05	$ 0.33	$ 0.11

(1) In the third quarter of 2006, operating income includes the reinstatement of deferred energy of approximately $180 million.

(2) In the fourth quarter of 2006, income from continuing operations includes a gain of $62.9 million due to the sale of TGPC's partnership interest in TGTC.

(3) In the third quarter of 2005, income from continuing operations includes a charge of $54 million for the inducement for debt conversion.

(4) In the fourth quarter of 2005, income from continuing operations includes the reversal of $20.9 million in interest charges as a result of settlements with terminated suppliers.

(5) Operating income and income from continuing operations differs from amounts previously reported in the March 31, June 30 and September 30, 2006 10Q's by a reduction of $(9), $(48), and $(15), respectively, due to SPCOM being classified as assets held for use rather than as discontinued operation. See Note 18, Discontinued Operations and Disposal and Impairment of Long-Lived Assets.

(6) Operating income and income from continuing operations differs from amounts previously reported in the March 31, June 30, and September 30, 2005 10Q's by $5, $1 and $(134), respectively, due to SPCOM being classified as assets held for use rather than as discontinued operations. See Note 18, Discontinued Operations and Disposal and Impairment of Long-Lived Assets.

Nevada Power Company

2006 Quarter Ended	**March**	**June**	**September**	**December**
Operating revenues	**$381,275**	**$543,869**	**$ 776,235**	**$422,702**
Operating income	**$ 25,663**	**$ 62,019**	**$ 244,920[1]**	**$ 18,670**
NET INCOME (LOSS)	**$ (3,296)**	**$ 28,456**	**$ 211,113**	**$ (11,733)**

2005 Quarter Ended	March	June	September	December
Operating revenues	$ 354,134	$ 451,384	$ 675,181	$ 402,568
Operating income	$ 23,265	$ 54,031	$ 126,173	$ 25,358
NET INCOME (LOSS)	$ (8,033)	$ 20,969	$ 99,472	$ 20,326[2]

(1) In the third quarter of 2006, operating income includes the reinstatement of deferred energy costs of approximately $180 million.
(2) In the fourth quarter of 2005, income from continuing operations includes the reversal of $17.7 million in interest charges as a result of settlements with terminated suppliers.

Sierra Pacific Power Company

2006 Quarter Ended	**March**	**June**	**September**	**December**
Operating revenues	**$325,497**	**$277,319**	**$ 305,445**	**$321,969**
Operating income	**$ 29,991**	**$ 24,803**	**$ 36,543**	**$ 28,680**
NET INCOME	**$ 13,272**	**$ 8,999**	**$ 20,028**	**$ 15,410**
Earnings (deficit) applicable to common stock	**$ 12,297**	**$ 7,633**	**$ 20,028**	**$ 15,410**

2005 Quarter Ended	March	June	September	December
Operating revenues	$ 294,548	$ 249,335	$ 283,683	$ 318,131
Operating income (loss)	$ 29,519	$ 21,710	$ 38,139	$ 26,936
NET INCOME	$ 12,137	$ 4,899	$ 21,858	$ 13,180[1]
Earnings (deficit) applicable to common stock	$ 11,162	$ 3,924	$ 20,883	$ 12,205

(1) In the fourth quarter of 2005, income includes the reversal of $3.2 million in interest expense due to the settlement with Enron.

ANNUAL REPORT ON FORM 10-K

The SEC Annual Report on Form 10-K is available free of charge by written request to the company's corporate headquarters or can be downloaded from the company's website: www.sierrapacificresources.com

Address request to:
Shareholder Relations
Sierra Pacific Resources
P.O. Box 30150
Reno, Nevada 89520-3150

CEO/CFO CERTIFICATIONS

The most recent certifications by our Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to our Form 10-K. We have also filed with the New York Stock Exchange the most recent Annual CEO Certification as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual.

INDEPENDENT ACCOUNTANT

Deloitte & Touche LLP
Reno, Nevada

ANALYST CONTACT

Britta Carlson
Sierra Pacific Resources
Investor Relations
P.O. Box 98910
Las Vegas, Nevada 89151-0001
(702) 367-5624

NYSE SYMBOL

Sierra Pacific Resources' common stock is traded on the New York Stock Exchange under the symbol SRP.

SHAREHOLDER RELATIONS

For shareholder records and dividend disbursement information, contact our Shareholder Relations Department:

Sierra Pacific Resources
Shareholder Relations
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

Website:
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

Telephone inquiries and address changes may be made to Sierra Pacific Resources at (800) 662-7575 (toll free) or (775) 834-3610 between 7 a.m. and 5 p.m. Pacific Time. General written inquiries and address changes should be sent to Wells Fargo Shareowner Services at either of the addresses listed below:

Wells Fargo Shareowner Services
P.O. Box 64874
St. Paul, Minnesota 55164-0874

Wells Fargo Shareowner Services
161 North Concord Exchange St.
South St. Paul, Minnesota 55075-1139

Telephone inquiries may also be made to a Wells Fargo Shareowner Services representative at (877) 778-6783 (toll free) or (651) 450-4063 between 7:00 a.m. and 7:00 p.m. Central Time. In addition, the Wells Fargo automated response system is available 24 hours a day, 7 days a week.

LOST OR STOLEN CERTIFICATES

If your stock certificates have been lost, stolen, or destroyed, please notify our Stock Transfer Agent, Wells Fargo Shareowner Services.

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 on Monday, May 7, 2007, at 10:00 a.m. at the Grand Sierra Resort and Casino, 2500 E. Second Street, Reno, Nevada.

2006 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.

STOCK INFORMATION

Sierra Pacific Resources' Common Stock is traded on the New York Stock Exchange (symbol SRP). The dividends paid per share and high and low sale prices of the common stock as reported by the New York Stock Exchange net composite price history for 2006 and 2005 are as follows:

	Dividends Paid Per Share	High	Low
2006			
First Quarter	**$.000**	**$14.60**	**$12.68**
Second Quarter	**.000**	**14.35**	**12.68**
Third Quarter	**.000**	**14.91**	**13.30**
Fourth Quarter	**.000**	**17.50**	**14.29**
2005			
First Quarter	$ .000	$ 11.30	$ 9.00
Second Quarter	.000	13.05	10.11
Third Quarter	.000	15.36	12.05
Fourth Quarter	.000	15.20	12.34

BOARD OF DIRECTORS

Front, left to right: Walter M. Higgins, Donald D. Snyder, Krestine M. Corbin, Mary Lee Coleman, Philip G. Satre, Brian J. Kennedy, Theodore J. Day;
Back, left to right: Michael W. Yackira, Clyde T. Turner, Jerry E. Herbst, James R. Donnelley, John F. O'Reilly, Joseph B. Anderson, Jr.

Walter M. Higgins
Chairman and Chief Executive Officer of Sierra Pacific Resources; Director and Chief Executive Officer of Nevada Power Company and Sierra Pacific Power Company.

Joseph B. Anderson, Jr.
Chairman and CEO of TAG Holdings, LLC, which owns several manufacturing and service-based enterprises in North America and Asia.

Mary Lee Coleman
President of Coleman Enterprises, a developer of shopping centers and industrial parks.

Krestine M. Corbin
President and Chief Executive Officer of Sierra Machinery Incorporated, a machine tool manufacturing company.

Theodore J. Day
Chairman of Dacole Company, an investment firm; formerly Senior Partner of Hale, Day, Gallagher Company, a real estate brokerage and investment firm.

James R. Donnelley
Partner, Stet & Query, Ltd., a family-owned investment company; Director and past Chairman, PMP Ltd.; and retired Vice Chairman of the Board for R.R. Donnelley & Sons Company.

Jerry E. Herbst
Chief Executive Officer of Terrible Herbst, Inc., a gaming, resort and gasoline retail company.

Brian J. Kennedy
President and Chief Executive Officer of Argonaut, LLC; Chairman of Meridian Gold, Inc.; past President and Chief Operating Officer of FMC Gold Company.

John F. O'Reilly
Chairman and Chief Executive Officer of the law firm of O'Reilly Law Group, LLC and John F. O'Reilly, APC; and Chairman and an Officer and/or Board member of various family-owned business entities and related investments and businesses.

Philip G. Satre
Retired Chairman of the Board, Harrah's Entertainment, Inc., a gaming entertainment company.

Donald D. Snyder
Retired President and Board member of Boyd Gaming Corporation, a gaming entertainment company.

Clyde T. Turner
Owner and Manager of Turner Investments, Ltd., a general-purpose investment company; co-owner of Global Trust Ventures, LLC, a private equity fund; and co-owner of Global Trust Ventures Management, LLC.

Michael W. Yackira
President and Chief Operating Officer of Sierra Pacific Resources; Director of Nevada Power Company and Sierra Pacific Power Company.

SENIOR OFFICERS

Front, left to right: Michael W. Yackira, Walter M. Higgins, Paul J. Kaleta, Jeffrey L. Ceccarelli;
Back, left to right: Donald "Pat" Shalmy, Roberto R. Denis, Stephen R. Wood, William D. Rogers

Walter M. Higgins
Chairman of the Board and Chief Executive Officer

Michael W. Yackira
President and Chief Operating Officer

Donald L. "Pat" Shalmy
Corporate Senior Vice President, Policy & External Affairs; President, Nevada Power Company

Jeffrey L. Ceccarelli
Corporate Senior Vice President, Service Delivery & Operations; President, Sierra Pacific Power Company

Roberto R. Denis
Corporate Senior Vice President, Energy Supply

Paul J. Kaleta
Corporate Senior Vice President, General Counsel and Corporate Secretary

Stephen R. Wood
Corporate Senior Vice President, Administration

William D. Rogers
Corporate Senior Vice President, Chief Financial Officer and Treasurer

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