UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2010**

Commission File	Registrant, Address of Principal Executive Offices and Telephone	I.R.S. Employer Identification	State of
1-08788	NV ENERGY, INC. 6226 West Sahara Avenue Las Vegas, Nevada 89146 (702) 402-5000	88-0198358	Nevada
2-28348	NEVADA POWER COMPANY d/b/a NV ENERGY 6226 West Sahara Avenue Las Vegas, Nevada 89146 (702) 402-5000	88-0420104	Nevada
0-00508	SIERRA PACIFIC POWER COMPANY d/b/a NV ENERGY P.O. Box 10100 (6100 Neil Road) Reno, Nevada 89520-0024 (89511) (775) 834-4011	88-0044418	Nevada

(Title of each class)	(Name of exchange on which registered)
Securities registered pursuant to Section 12(b) of the Act: Securities of NV Energy, Inc.: Common Stock, $1.00 par value	New York Stock Exchange
Securities registered pursuant to Section 12(g) of the Act: Securities of Nevada Power Company: Common Stock, $1.00 stated value Securities of Sierra Pacific Power Company: Common Stock, $3.75 par value	

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

NV Energy, Inc. Yes ☑ No ☐ Nevada Power Company Yes ☐ No ☑ Sierra Pacific Power Company Yes ☐ No ☑

Indicate by check mark if each of the registrants is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐ (Response applicable to all registrants).

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether any registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. (See definition of ''large accelerated filer'', ''accelerated filer'' and ''smaller reporting company'' in Rule 12b-2 of the Exchange Act).

NV Energy, Inc.: Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Nevada Power Company: Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☑ Smaller reporting company ☐

Sierra Pacific Power Company: Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☑ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑ (Response applicable to all registrants)

State the aggregate market value of NV Energy, Inc.'s common stock held by non-affiliates. As of June 30, 2010: $2,776,606,796

Indicate the number of shares outstanding of each of the issuer's classes of Common Stock, as of the latest practicable date.

Common Stock, $1.00 par value, of NV Energy, Inc. outstanding at February 21, 2011: 235,591,058 Shares

NV Energy, Inc. is the sole holder of the 1,000 shares of outstanding Common Stock, $1.00 stated value, of Nevada Power Company.

NV Energy, Inc. is the sole holder of the 1,000 shares of outstanding Common Stock, $3.75 par value, of Sierra Pacific Power Company.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of NV Energy, Inc.'s definitive proxy statement to be filed in connection with the annual meeting of shareholders, to be held May 3, 2011, are incorporated by reference into Part III hereof.

This combined Annual Report on Form 10-K is separately filed by NV Energy, Inc., Nevada Power Company and Sierra Pacific Power Company. Information contained in this document relating to Nevada Power Company is filed by NV Energy, Inc. and separately by Nevada Power Company on its own behalf. Nevada Power Company makes no representation as to information relating to NV Energy, Inc. or its subsidiaries, except as it may relate to Nevada Power Company.

Information contained in this document relating to Sierra Pacific Power Company is filed by NV Energy, Inc. and separately by Sierra Pacific Power Company on its own behalf. Sierra Pacific Power Company makes no representation as to information relating to NV Energy, Inc. or its subsidiaries, except as it may relate to Sierra Pacific Power Company.

NV ENERGY, INC.
NEVADA POWER COMPANY
SIERRA PACIFIC POWER COMPANY
2010 ANNUAL REPORT ON FORM 10-K
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ACRONYMS AND TERMS

(The following common acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
2010 Form 10-K	NVE's, NPC's and SPPC's Annual Report on Form 10-K for the year ended December 31, 2010
2011 Proxy Statement	NVE's, NPC's and SPPC's Proxy Statement for 2011
AFUDC - debt	Allowance for borrowed funds used during construction
AFUDC - equity	Allowance for equity funds used during construction
BCP	Nevada Bureau of Consumer Protection
BOD	Board of Directors
BTER	Base Tariff Energy Rate
BTGR	Base Tariff General Rate
California Assets	Sale of SPPC's California electric distribution and generation assets to CalPeco
CalPeco	California Pacific Electric Company
Calpine	Calpine Corporation
CDWR	California Water Resources Department
CEO	Chief Executive Officer of NV Energy, Inc.
CIAC	Contributions in Aid of Construction
Clark Generating Station	550 MW nominally rated William Clark Generating Station
Clark Peaking Units	600 MW nominally rated peaking units at the William Clark Generating Station
CO_2	Carbon Dioxide
CPA	Certified Public Accountant
CPUC	California Public Utilities Commission
CWIP	Construction Work-In-Progress
d/b/a	Doing business as
DEAA	Deferred Energy Accounting Adjustment
DOE	Department of Energy
DOS	Distribution Only Service
DSM	Demand Side Management
Dth	Decatherm
EEC	Ely Energy Center
EEIR	Energy Efficiency Implementation Rate
EEPR	Energy Efficiency Program Rate
EPA	United States Environmental Protection Agency
EPS	Earnings Per Share
EROC	Enterprise Risk Oversight Committee
ESP	Energy Supply Plan
FASB	Financial Accounting Standards Board
FASC	FASB Accounting Standards Codification
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Ltd.
GAAP	Accounting Principles Generally Accepted in the United States
GBT	Great Basin Transmission, LLC

Acronym/Term	Meaning
Goodsprings	7.5 MW nominally rated Goodsprings Recovered Energy Generating Station
GPSF-B	Global Project & Structured Finance Corporation
GRC	General Rate Case
GWh	Gigawatt Hour
Harry Allen Generating Station	142 MW nominally rated Harry Allen Generating Station
Higgins Generating Station	598 MW nominally rated Walter M. Higgins, III Generating Station
IBEW	International Brotherhood of Electrical Workers
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
kV	Kilovolt
kWh	Kilowatt Hour
LDC	Local Distributing Company
Lenzie Generating Station	1,102 MW nominally rated Chuck Lenzie Generating Station
LIBOR	London Interbank Offered Rate
MMBtu	Million British Thermal Units
Mohave Generating Station	1,580 MW nominally rated Mohave Generating Station
Moody's	Moody's Investors Services, Inc.
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
Navajo Generating Station	255 MW nominally rated Navajo Generating Station
NDEP	Nevada Division of Environmental Protection
NEICO	Nevada Electrical Investment Company
NERC	North American Electric Reliability Corporation
Newmont	Newmont Mining Corporation
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NOL	Net Operating Loss
NPC	Nevada Power Company d/b/a NV Energy
NPC's Credit Agreement	$600 million Revolving Credit Facility entered into in April 2010 between NPC and Wells Fargo, N.A., as administrative agent for the lenders a party thereto
NPC's Indenture	NPC's General and Refunding Mortgage Indenture dated as of May 1, 2001, between NPC and The Bank of New York Mellon Trust Company N.A., as Trustee
NRSRO	Nationally Recognized Statistical Rating Organization
NVE	NV Energy, Inc.
NV Energize	NVE project which includes Advanced Meter Infrastructure, Smart Grid Technology and Meter Data Management.
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
ON Line	250 mile 500 kV transmission line connecting NVE's northern and southern service territories
Peabody	Peabody Western Coal Company

Acronym/Term	Meaning
PEC	Portfolio Energy Credit
Piñon Pine	Piñon Pine Coal Gasification Demonstration Project
Portfolio Standard	Nevada Renewable Energy Portfolio Standard
PPC	Piñon Pine Corporation
PPIC	Piñon Pine Investment Company
PUCN	Public Utilities Commission of Nevada
Reid Gardner Generating Station	325 MW nominally rated Reid Gardner Generating Station
REPR	Renewable Energy Program Rate
RFP	Request for Proposal
ROE	Return on Equity
ROR	Rate of Return
S&P	Standard & Poor's
Salt River	Salt River Project
SEC	United States Securities and Exchange Commission
Silverhawk Generating Station	395 MW nominally rated Silverhawk Generating Station
SNWA	Southern Nevada Water Authority
SPC	Sierra Pacific Communications
SPPC	Sierra Pacific Power Company d/b/a NV Energy
SPPC Credit Agreement	$250 million Revolving Credit Facility entered into in April 2010 between SPPC and Bank of America, N.A., as administrative agent for the lenders a party thereto
SPPC's Indenture	SPPC's General and Refunding Mortgage Indenture, dated as of May 1, 2001, between SPPC and The Bank of New York Mellon Trust Company N.A., as Trustee
SPR	Sierra Pacific Resources
SRSG	Southwest Reserve Sharing Group
TMWA	Truckee Meadows Water Authority
Tracy Generating Station	541 MW nominally rated Frank A. Tracy Generating Station
TUA	Transmission Use Agreement
U.S.	United States of America
Utilities	Nevada Power Company and Sierra Pacific Power Company
Valmy Generating Station	261 MW nominally rated Valmy Generating Station
VIE	Variable Interest Entity
WECA	Western Energy Crisis Adjustment
WSPP	Western Systems Power Pool

FORWARD LOOKING STATEMENTS

The discussion of forward looking statements in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*, is incorporated herein by reference.

PART I

ITEM 1. BUSINESS

NV Energy, Inc. is an investor-owned holding company that was incorporated under Nevada law on December 12, 1983. The company's stock is traded on the New York Stock Exchange under the symbol ''NVE''. NVE's mailing address is 6226 West Sahara Avenue, Las Vegas, Nevada 89146.

NVE has five primary, wholly-owned subsidiaries: Nevada Power Company d/b/a NV Energy, Sierra Pacific Power Company d/b/a NV Energy, Sierra Pacific Energy Company, NVE Insurance Company, Inc. and Lands of Sierra. References to NVE refer to the consolidated entity, except where the context provides otherwise. NPC and SPPC are referred to collectively in this report as the''Utilities''.

The Utilities operate three business segments, as defined by the Segment Reporting Topic of the FASC: NPC electric; SPPC electric; and SPPC natural gas. Electric service is provided by NPC to Las Vegas and surrounding Clark County, and by SPPC to northern Nevada. Natural gas service is provided by SPPC in the Reno-Sparks area of Nevada. The Utilities are the major contributors to NVE's financial position and results of operations. Other subsidiaries either do not meet the definition of a segment or are below the quantitative threshold for separate segment disclosure and are combined under ''all other'' in the following pages. Parenthetical references are included after each major section title to identify the specific entity or entities addressed in the section. See Note 2, *Segment Information* of the Notes to Financial Statements, for further discussion.

NPC is a Nevada corporation organized in 1921 and, by itself and through a predecessor corporation, has been providing electric services to southern Nevada since 1906. NPC became a subsidiary of NVE in July 1999. Its mailing address is 6226 West Sahara Avenue, Las Vegas, Nevada 89146.

NEICO is a wholly-owned subsidiary of NPC. NEICO is a 25% member of Northwind Aladdin, LLC, the other 75% of Northwind Aladdin, LLC is owned by Macquarie Infrastructure Company Trust.

A Nevada corporation since 1965, SPPC was originally incorporated in Maine in 1912. SPPC became a subsidiary of NVE in 1984. Its mailing address is P. O. Box 10100 (6100 Neil Road), Reno, Nevada 89520-0024.

SPPC has three primary, wholly-owned subsidiaries: GPSF-B, PPC and PPIC. GPSF-B, PPC and PPIC, collectively, own Piñon Pine Company, LLC, which was formed to utilize federal income tax credits available under Section 20 of the Internal Revenue Code associated with the alternative fuel (syngas) produced by the coal gasifier located at the Piñon Pine facility.

Periodic reports for NVE, NPC and SPPC on Form 10-K and Form 10-Q and current reports on Form 8-K are made available to the public, free of charge, on NVE's website (www.nvenergy.com) through links on this website to the SEC's website at www.sec.gov, as soon as reasonably practicable after they have been filed with the SEC. The contents of the above referenced website address are not part of this Form 10-K. The public may also read any copy of materials filed with the SEC by NVE, NPC or SPPC at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-(800) SEC-0030. Reports, proxy and information statements, and other information regarding NVE, NPC and SPPC may also be obtained directly from the SEC's website. Available on the nvenergy.com website are the code of ethics for the chief executive officer, chief financial officer and controller, charters for the Audit, Compensation, and Nominating and Governance Committees of NVE's BOD and our corporate governance and standards of conduct guidelines. Printed copies of these documents may be obtained free of charge by writing to NVE's Corporate Secretary at NV Energy, Inc., 6226 West Sahara Avenue, Las Vegas, Nevada 89146.

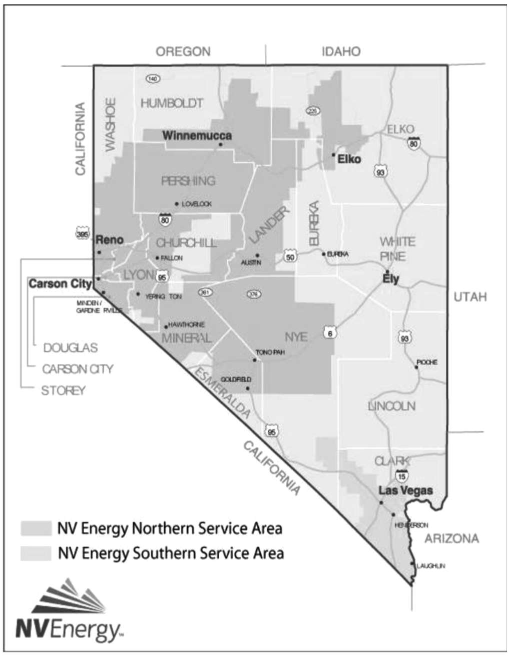
The statistical data used throughout this 2010 Form 10-K, other than data relating specifically solely to NVE and its subsidiaries, are based upon independent industry publications, government publications, reports by market research firms or other published independent sources. We did not commission any of these publications or reports. These publications generally state that they have obtained information from sources believed to be reliable, but do not guarantee the accuracy or completeness of such information. While we believe that each of these studies and publications is reliable, we have not independently verified such data and make no representation as to the accuracy of such information.

Overview

NPC and SPPC are public utilities that generate, transmit and distribute electric energy in Nevada and, in the case of SPPC, also delivers natural gas service. At year-end 2010, NPC served approximately 830,000 electric customers primarily in Las Vegas, North Las Vegas, Henderson and adjoining areas, including Nellis Air Force Base and the DOE's Nevada Test Site in Nye County. At year end 2010, SPPC served approximately 367,000 electric customers and its electric service territory covered over 50,000 square miles of 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. However, on January 1, 2011, SPPC sold its California assets, as discussed in Note 16, *Assets Held for Sale*, of the Notes to Financial Statements. Additionally, SPPC provided natural gas service to approximately 151,000 customers in an area of about 800 square miles in Nevada's Reno/Sparks area.

Major industries served by the Utilities include gaming/recreation, mining, warehousing/manufacturing and other governmental entities. The Utilities' revenues and operating income are subject to fluctuations during the year due to the impacts that 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 also occurs in the summer, with a slightly lower peak demand in the winter. SPPC's gas business typically peaks in the winter months due to heating demands.

NPC and SPPC service territories are as follows:



Beginning in 2007, the Utilities embarked on a three part energy supply strategy to manage resources against their load by encouraging energy efficiency and conservation programs, the purchase and development of renewable energy projects, construction of generating facilities and expanding transmission capability in an effort to reduce their reliance on purchased power.

Energy Efficiency and Conservation Programs

A part of our strategy to reduce dependence on purchased power is to manage our resources against our load requirements with energy efficiency and conservation programs for our customers, also known as DSM programs. NVE has designed a portfolio of cost effective DSM programs that allow every customer to take advantage of savings from energy efficiency measures. DSM programs are marketed across all segments of customer classes (residential, commercial, industrial, public and low income).

In 2010, the Utilities invested $45.2 million towards energy efficiency and conservation programs. The Utilities current 2011 budget includes approximately $89 million for these programs. In 2010, the PUCN approved DSM programs to increase energy efficiency and conservation programs totaling approximately $209.9 million and $36 million for NPC and SPPC, respectively, over the three year action plan.

The Portfolio Standard, discussed below, allows energy efficiency measures from qualified conservation programs to satisfy up to 25% of the Portfolio Standard. Under this provision, a PEC is created for each kWh of energy conserved by qualified energy efficiency programs. In addition, energy saved during peak demand hours earns double the PECs for each kWh of energy conserved. After the DSM percentage allowance is fully utilized, NVE's strategy is to assess economic conditions and potential rate impacts in pursuing the implementation of cost effective DSM programs needed to achieve future Portfolio Standard requirements.

In addition, NVE was awarded a $138 million grant in stimulus funding, made available through the American Recovery and Reinvestment Act, from the DOE specifically for NVE's $301 million NV Energize project. In August of 2010, the PUCN approved the project. In September, the grant was increased to $139 million and NVE committed to a $303 million total project budget in order to include the development of a Consumer Confidence Plan. The plan will address consumer education and communication issues associated with the deployment of the Smart Grid infrastructure necessary to enable: 1) the achievement of metering and customer service operating savings; 2) the expansion of demand response and energy efficiency benefits; and 3) provide customers better information to help manage their energy usage.

Purchase and Development of Renewable Energy Resources

The Portfolio Standard requires a specific percentage of an electric service provider's total retail energy sales be obtained from renewable energy resources. Renewable resources include biomass, geothermal, solar, waterpower, wind and qualified recovered energy generation projects. In addition, the Portfolio Standard allows energy efficiency measures from qualified conservation programs to meet up to 25% of the portfolio percentage. In 2011 and 2012, the Utilities are required to obtain an amount of PECs equivalent to 15% of their total retail energy from renewables. Currently, the Portfolio Standard increases to 18% for 2013 and 2014, to 20% in 2015, after which it increases to 22% for the years 2020 through 2024, and to 25% for 2025 and beyond. Moreover, not less than 5% of the total Portfolio Standard must be satisfied from solar resources until 2016 when a minimum of 6% must be solar.

The Utilities' compliance with the Portfolio Standard is dependent on the supply of PECs resulting from renewable energy generation and DSM activities. The Utilities acquire PECs through purchase power contracts, investments in renewable generating facilities and DSM programs. In addition in 2009, legislation was passed in Nevada that permits renewable energy purchased outside Nevada to qualify towards the Portfolio Standard, which among other benefits, give the Utilities the ability to purchase PECs on a short term basis especially in an effort to fulfill shortfalls which may occur due to the success or timing in development of renewable energy projects, weather or other supplier issues.

Currently, NPC and SPPC have contracts for 807 MW and 209 MW (nominally rated), respectively of renewable energy resources from a variety of geothermal, solar, hydro, biomass, wind projects and NPC's 7.5 MW (nominally rated) recovered energy project. Approximately 607 MWs (nominally rated) of NPC's resources are in various stages of development or may be contingent upon completion of ON Line, as discussed below. In 2010 the PUCN approved a stipulation under which NPC was able to fully offset its PEC shortfall for compliance year 2009 with PECs acquired in 2010, permitted by Nevada state law as discussed above, and surplus PECs loaned by SPPC. In 2010, the Utilities acquired sufficient PECs to fully meet the Portfolio Standard for 2010, as well as to offset the shortfall from 2009.

Construction of Generating and Transmission Facilities and Optimizing the Operation of Current Generation Assets

In 2011, NPC expects to complete construction of the 500 MW (nominally rated) natural gas generating station at the existing Harry Allen Generating Station, which is expected to be operational by mid 2011. In 2010, NPC completed construction of the 7.5 MW (nominally rated) Goodsprings recovered energy generating station.

In February 2011, NVE and the Utilities consummated their agreement with GBT to jointly construct and own ON Line, a 500 Kv transmission line, as discussed further under Transmission and the Utilities' IRP sections. The completion of ON Line, expected in late 2012, will connect NVE's southern and northern territories, provide the ability to jointly dispatch energy throughout the state, provide access to isolated renewable energy resources in parts of northern and eastern Nevada and enhance NVE's ability to meet its Portfolio Standard, discussed above, and lower costs to our customers.

Business and Competitive Environment

Operations

NPC and SPPC Electric

The Utilities are charged with meeting the energy needs of the residential and business populations in Nevada, as well as the public sectors in Nevada. Revenues are impacted by rate changes, cost of fuel and purchased power, seasonal or atypical weather and customer use. The Utilities' electric peak demand occurs in the summer. Therefore, the Utilities' revenues and associated expenses are not incurred or generated evenly throughout the year.

To serve their customer base, the Utilities generate electricity and purchase power in accordance with an ESP, as discussed in more detail later in this section, under *Energy Supply*.

SPPC Gas

SPPC's natural gas company or LDC is responsible for providing natural gas to residential, commercial and industrial customers. There are approximately 151,000 customers in the LDC which primarily covers the greater Reno/Sparks area in Washoe County. SPPC is currently implementing a program (known as the Blackwrap replacement program) to replace some of the oldest distribution pipe in its system installed between 1948 and 1959. Since 2005, SPPC has spent $22.0 million replacing over 16 miles of Blackwrap and associated customer services.

SPPC is well connected with several major gas producing regions and gas transportation systems into northern Nevada. SPPC's gas distribution system receives gas supplies from two interstate natural gas pipelines, the Paiute Pipeline Company and the Tuscarora Gas Transmission Company. In addition, SPPC has contracted for natural gas storage services to supplement firm and spot market purchases.

Regulatory Environment

The FERC and PUCN regulate portions of the Utilities' accounting practices and electricity and natural gas rates. The FERC has jurisdiction under the Federal Power Act with respect to wholesale 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 buy transportation for natural gas. The PUCN has authority over rates charged to retail customers, the issuance of securities by the Utilities and transactions with affiliated parties.

Nevada state regulations require the Utilities to file electric GRCs every three years with the PUCN to adjust rates, based primarily on cost of service and return on investment. Nevada state regulations also require the Utilities to file annual DEAA applications to either recover or refund electric balances that have been deferred and that represent the difference between fuel and purchased power costs actually incurred and the amounts collected in current retail rates. Additionally, the Utilities are required to file to reset BTERs quarterly, reflecting more recent fuel and purchased power costs. Moreover, in 2010, the PUCN adopted regulations authorizing an electric utility to recover an amount from its customers that is attributable to the measurable and verifiable effects associated with the Utilities' implementation of efficiency and conservation programs approved by the PUCN. The Utilities filed their first rate case with respect to this new regulation, referred to by the Utilities as the EEIR Rate and EEPR Rate, in October 2010 and will continue to file rate cases annually in March, thereafter. See Note 3, *Regulatory Actions*, of the Notes to Financial Statements, for further discussion on the various rate cases.

Nevada state regulations further require annual filings to reset base purchased gas rates and recover deferred balances that include purchased gas costs above or below the amounts collected in current rates. The regulations also require a Gas Supply Report as well as a Gas Informational Report to be filed annually. Natural gas commodity costs are passed directly through to customers on a dollar for dollar basis. SPPC may also file gas GRCs to adjust gas division rates including cost of service and return on investment. Rate cases are discussed in more detail in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*, *Regulatory Proceedings*, and Note 3, *Regulatory Actions*, of the Notes to Financial Statements.

Competition

NPC and SPPC Electric

The Utilities operate under franchise agreements in their respective operating areas; therefore, competition in their operating areas is limited. Under Nevada state law, commercial customers with an average annual load of 1 MW or more may file a letter of intent and application with the PUCN to acquire electric energy, capacity, and ancillary services from another provider. The law requires customers wishing to choose a new supplier to receive the approval of the PUCN and meet public interest standards. In particular, departing customers must secure new energy resources that are not under contract to NPC or SPPC, the departure must not burden the Utilities with increased costs or cause any remaining customers to pay increased costs, and the departing customers must pay their portion of any deferred energy balances. The PUCN adopted regulations prescribing the criteria that will be used to determine if there will be negative impacts to remaining customers or to the Utilities. Customers wishing to choose a new supplier must provide 180-day notice to NPC or SPPC. The Utilities would continue to provide transmission, distribution, metering, and billing services to such customers.

Currently, there are no material applications pending with the PUCN to exit the system in NPC's or SPPC's service territory. In the event a customer were to exit the system, the departure would not have a material impact on the Utilities net income.

SPPC Gas

SPPC's natural gas LDC business is subject to competition from other suppliers and other forms of energy available to its customers. Large gas customers using 12,000 therms per month with fuel switching capability are allowed to participate in the Incentive Natural Gas Rate tariff. Once a service agreement has been executed, a customer can compare natural gas prices under this tariff to alternative energy sources and choose their source of fuel. Additionally, customers using greater than 1,000 therms per day have the ability to secure their own gas supplies under a transportation tariff. As of January 1, 2011, there were 17 large customers securing their own gas supplies. These customers have a combined firm distribution load of approximately 5,803 Dth per day. Transportation customers continue to pay firm and interruptible distribution charges. These customers are responsible for procuring and paying for their own gas supply, which reduces SPPC's purchases, but does not have an impact on net income.

Sales

In 2010, NPC's and SPPC's electric revenues were approximately $2.3 billion and $836.8 million, respectively. SPPC's natural gas business accounted for approximately $191 million in 2010 operating revenues or 18.6% of SPPC's total revenues. NPC's peak electric load increased at an average annual growth rate of 0.1% over the past five years, while SPPC's decreased by 1.5%. In 2010, NPC's and SPPC's electric system peaks were 5,604 MW and 1,611 MW, respectively, compared to 5,586 MW and 1,554 MW, respectively, in 2009. NPC's total retail electric MWh sales have increased at an average annual growth rate of 1.2% over the past five years; however, total retail electric MWh sales declined slightly in 2010 compared to 2009 as discussed below. SPPC's total retail electric MWh sales have decreased at an average annual rate of 2.6% over the past five years primarily due to a decrease in mining customers discussed below.

NPC's electric customers by class contributed the following MWh sales:

	MWh Sales (Billed and Unbilled)					
	2010		2009		2008	
	MWh	% of Total	MWh	% of Total	MWh	% of Total
Retail:						
Residential	8,684,386	41.6%	8,893,542	41.8%	9,041,403	41.7%
Commercial & Industrial:						
Gaming/Recreation/ Restaurants	3,215,710	15.4%	3,392,658	16.0%	3,695,156	17.0%
All Other Retail	8,742,166	41.9%	8,670,931	40.8%	8,644,314	39.8%
Total Retail	20,642,262	98.9%	20,957,131	98.6%	21,380,873	98.5%
Wholesale	1,262	0.0%	69,915	0.3%	83,123	0.4%
Sales to Public Authorities	231,072	1.1%	240,302	1.1%	231,647	1.1%
Total	20,874,596	100.0%	21,267,348	100.0%	21,695,643	100.0%

Total retail MWh sales decreased approximately 1.5% in 2010 from 2009, primarily due to a decrease in customer usage due to conservation programs, economic conditions and hotter than normal weather in May 2009. NPC's average retail residential customer count increased by 0.4% in 2010 from 2009.

NPC's service territory, which consists primarily of Las Vegas, key economic indicators, as outlined below, continued to decline or have shown moderate improvement from 2009:

- Unemployment in Las Vegas was 14.9% in December 2010, up from 13% a year ago;
- In southern Nevada, construction activity, another leading indicator, has seen a decrease in the number of commercial permits while residential permits has remained relatively flat;
- Construction employment decreased 22.8% as of November 2010 compared to November 2009;

• As of November 2010, taxable sales increased 0.9% from a year ago;

• As of December 2010, gaming revenues declined 2.6% from a year ago;

• As of December 2010, visitor volume increased 3.7% from a year ago;

• As of December 2010, the hotel/motel occupancy rate in Las Vegas increased approximately 1.1% from a year ago; and

• The estimated room growth rate in 2010 was 1.2% primarily due to The Cosmopolitan Resort and Casino which added approximately 2,000 rooms. In 2011, room growth is expected to increase to 1.0% and then slow to 0.3% in 2012.

SPPC's electric customers by class contributed the following MWh sales:

	MWh Sales (Billed and Unbilled)					
	2010		2009		2008	
	MWh	% of Total	MWh	% of Total	MWh	% of Total
Retail:						
Residential	2,465,049	30.4%	2,502,537	30.6%	2,523,923	29.4%
Commercial and Industrial:						
Mining	1,506,866	18.6%	1,405,087	17.1%	1,632,882	19.0%
All Other Retail	4,108,834	50.6%	4,254,749	51.9%	4,403,403	51.2%
Total Retail	8,080,749	99.6%	8,162,373	99.6%	8,560,208	99.6%
Wholesale	13,797	0.2%	14,993	0.2%	15,577	0.2%
Sales to Public Authorities	16,459	0.2%	16,535	0.2%	16,108	0.2%
Total	8,111,005	100.0%	8,193,901	100.0%	8,591,893	100.0%

Total retail MWh sales decreased approximately 1.0% in 2010 from 2009, primarily due to a decrease in customer usage as a result of milder summer weather, conservation programs and economic conditions. Also contributing to the decrease in MWhs in 2010, compared to 2009 and 2008, is the transition of certain customers to DOS as discussed below. These decreases were partially offset by increased industrial usage primarily from a gold mining customer who resumed full operation in October 2009.

Mining is a leading industry in northern Nevada and comprises one of SPPC's largest classes of customers. According to the Nevada Mining Association, spot gold price levels, coupled with Nevada's reasonable regulatory environment, the State's favorable geology for gold deposits, and the industry's success in controlling its costs and attracting a high quality labor force offer a strong foundation for investment in continued mine development and the industry's continuing high level of energy usage. As discussed above, in 2009 and 2008, SPPC saw a decline in usage of mining customers as they switched to DOS service; however in 2010, mining customer usage increased as a result of a mining customer who restored operations in October 2009.

In SPPC's service territory, which consists primarily of Washoe County, key economic indicators, as outlined below, continue to decline or have shown moderate improvement from 2009:

- Unemployment in Washoe County was at 13.8% as of December 2010, up from 12.5% from a year ago;
- Construction employment decreased 26.0% as of November 2010 from November 2009;
- As of November 2010, taxable sales increased by 2.5% compared to a year ago; and
- As of December 2010, gaming revenues decreased 0.7% compared to a year ago.

SPPC has long-term electric service agreements with eight of its largest commercial and industrial customers, with yearly revenues under these agreements totaling approximately $59 million. For 2010, this represented approximately 7.0% of SPPC's electric operating revenues of approximately $836.8 million. Such agreements include requirements for customers to maintain minimum demand and load factor levels. In addition, they include provisions to recover all investments for customer-specific facilities that have been made by SPPC on their behalf.

Commercial customers who receive approval from the PUCN to acquire electric energy, capacity, and ancillary services from another provider, and who may have previously received service from SPPC under terms of a long-term service agreement, will migrate to being served under the provisions of a DOS agreement. Under a DOS agreement, customer-specific facilities charges will continue to be collected along with a flat distribution charge per meter.

Heating Degree Days (HDD) and Cooling Degree Days (CDD)

MWh usage may be affected by the change in heating degree or cooling degree days in a given year. A Degree Day indicates how far that day's average temperature departed from 65° F. Heating Degree Days measure heating energy demand and indicates how far the average temperature fell below 65° F. Cooling Degree Days measures cooling energy demand and indicates how far the temperature averaged above 65° F. For example, if a location had a mean temperature of 60° F on day 1 and 80° F on day 2, there would be 5 HDD's (65 minus 60) and 0 CDD's for day 1. In contrast, there would be 0 HDD's and 15 CDD's (80 minus 65) for day 2.

The following table shows the heating degree days and cooling degree days within NPC's and SPPC's service territories for each of the last three years.

	2010		2009		2008
	Amount	**Change from Prior Year**	**Amount**	**Change from Prior Year**	**Amount**
NPC					
HDD	1,895	0.3%	1,889	2.3%	1,846
CDD	3,648	-3.7%	3,790	0.4%	3,775
SPPC					
HDD	4,818	-3.7%	5,004	1.6%	4,923
CDD	922	-13.8%	1,069	-5.6%	1,132

Data Source: National Weather Service

Demand

Load and Resources Forecast

NPC's peak electric demand increased in 2010 to 5,604 MWs from 5,586 MWs in 2009. SPPC's peak electric demand increased in 2010 to 1,611 MWs from 1,554 MWs in 2009. Variations in energy usage occur as a result of varying weather conditions, economic conditions, and other energy usage behaviors, such as conservation efforts by our customers. These variations necessitate a continual balancing of loads and resources, and requires both purchases and sales of energy under short and long-term contracts and the prudent management and optimization of available resources.

The Utilities plan to meet their customers' needs through a combination of company-owned-generation and purchased power. See the Generation section and Purchased Power section below for details of the Utilities' generation and contracts for purchased power. Remaining needs will be met through power purchases through RFPs or short-term purchases. As shown in the tables below, the Utilities have sufficient resources to meet anticipated customer requirements. However, resource adequacy may be affected by a variety of factors including, but not limited to, the unplanned retirement of aging or less efficient generating stations, the timing or achievement of commercial operation with respect to renewable energy power projects not yet commercially operable, as well as the intermittent reliability of renewable energy resources, customer behavior with respect to DSM programs and environmental regulations which may limit our ability to operate certain generating units. Resource adequacy provides the Utilities the ability to maintain a reliable supply of energy; however as discussed under Resource Optimization, to the extent the resources are not needed, the Utilities will attempt to sell their additional availability in an effort to reduce costs.

Below are tables summarizing the forecasted summer electric capacity requirement and resource needs of the Utilities after consideration of energy conservation programs (assuming no curtailment of supply or load, and normal weather conditions) and the completion of ON Line, expected in late 2012, as discussed in the Transmission section later:

	Forecasted Electric Capacity Requirements and Resources (MW)				
	2011	2012	2013	2014	2015
NPC					
Total requirements[1]	6,251	6,209	6,104	6,163	6,205
Resources:					
Company-owned existing generation[2]	4,241	4,241	4,236	4,236	4,236
Company-owned new generation[3]	484	484	484	484	484
Contracts for power purchases	1,701	1,701	1,634	1,410	1,410
Contracts for renewable energy power purchases, not yet commercially operable[4]	-	59	77	113	235
Total resources	6,426	6,485	6,431	6,243	6,365
Total additional required (additional resources)[5]	(175)	(276)	(327)	(80)	(160)

(1) Includes projected system peak load plus 12% planning reserves. The decrease in total requirements from 2011 to 2013 is primarily due to an increase in conservation programs.

(2) Includes 233 MWs of peaking capacity at Reid Gardner Generating Station Unit No. 4, which is co-owned with CDWR, see Item 2, *Properties*.

(3) Includes 484 MWs combined cycle unit at the Harry Allen Generating Station expected to be completed mid 2011.

(4) Includes long term purchase power agreements for renewable energy that are not yet commercially operable and/or may not materialize due to project delays, under performance or cancelations.

(5) Total additional required is the difference between the total requirements and total resources. Total additional required represents the amount needed to achieve the forecasted system peak plus a planning reserve margin conversely; additional resources represents resources in excess of forecasted system peak plus a 12% planning reserve margin.

	Forecasted Electric Capacity Requirements and Resources (MW)				
	2011	**2012**	**2013**	**2014**	**2015**
SPPC					
Total requirements[1]	1,811	1,831	1,834	1,835	1,839
Resources:					
Company-owned existing generation	1,531	1,531	1,531	1,478	1,478
Contracts for power purchases	346	364	288	288	288
Total resources	1,877	1,895	1,819	1,766	1,766
Total additional required (additional resources)[2]	(66)	(64)	15	69	73

(1) Includes projected system peak load plus 15% planning reserves.

(2) Total additional required represents the difference between the total requirements and total resources. Total additional required represents the amount needed to achieve the forecasted system peak plus a planning reserve margin conversely, additional resources represents resources in excess of forecasted system peak plus a 15% planning reserve margin.

Resource Optimization

Resource optimization entails the responsible purchase and sale of electric power, fuel and financial energy products by the Utilities. The Utilities optimize their portfolios continuously in order to meet load obligations in a cost effective and reliable manner within transmission constraints. The Utilities continuously monitor the resources available to meet load obligations, recognizing the uncertainty not only in system conditions, such as planned and unplanned outages of generating or transmission facilities, but also in regional energy markets organized across different commodities, locations, demand and trading timeframes. As conditions change and new information becomes available, the Utilities optimize their portfolios as appropriate to account for changes in load, cost, volatility, reliability and other commercial or technical factors.

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

Energy Supply

Total System

The Utilities manage a portfolio of energy supply options. The availability of alternate resources allows the Utilities to dispatch their electric generation system in a more cost-effective manner under varying operating and fuel market conditions while maintaining system integrity. As shown below, during 2010, NPC generated approximately 70.8% of its total system requirements, purchasing the remaining 29.2%, and SPPC generated 59.4% of its total electric energy requirements, purchasing the remaining 40.6%.

	2010		2009		2008	
	MWh	% of Total	MWh	% of Total	MWh	% of Total
NPC						
Gas/Oil Generation	11,666,152	53.6%	12,793,249	57.8%	10,976,006	49.5%
Coal Generation	3,739,339	17.2%	3,632,385	16.4%	3,992,392	18.0%
Total Generated	15,405,491	70.8%	16,425,634	74.2%	14,968,398	67.5%
Total Purchased	6,350,795	29.2%	5,696,555	25.8%	7,190,431	32.5%
Total System(1)	21,756,286	100.0%	22,122,189	100%	22,158,829	100.0%

	2010		2009		2008	
	MWh	% of Total	MWh	% of Total	MWh	% of Total
SPPC						
Gas/Oil Generation	3,707,666	43.0%	3,852,662	43.4%	2,819,767	30.7%
Coal Generation	1,412,875	16.4%	1,729,466	19.5%	1,812,918	19.8%
Total Generated	5,120,541	59.4%	5,582,128	62.9%	4,632,685	50.5%
Total Purchased	3,509,767	40.6%	3,296,482	37.1%	4,547,062	49.5%
Total System(1)	8,630,308	100.0%	8,878,610	100.0%	9,179,747	100.0%

(1) Included in Total System is expected energy waste resulting from the transmission of electrical energy across power lines.

As a supplement to their own generation, the Utilities purchase spot, firm and non-firm energy to meet its customer demand requirements. Total energy supply includes purchases from outside the electric system due to limited control area generation and also the need to access market energy supplies. The Utilities decision to purchase this energy is based on economics, mitigation of availability risk, regulatory requirements and system import limits. Firm block purchases are transacted as both a price hedging strategy and to ensure that needed firm capacity is available over peak load periods. Spot market energy is purchased based on the economics of purchasing ''as-available'' energy when it is less expensive than the Utilities own generation, again, subject to net system import limits.

NPC's 2010 company generated MWhs decreased 6.2% from 2009. NPC's 2010 purchased power MWhs increased 11.5% compared to 2009 due to NPC's renewable energy purchases and plant outages within internal generation. SPPC's 2010 company generation decreased 8.3% compared to 2009. SPPC's 2010 purchased power MWhs increased 6.5% compared to 2009 due to plant outages within internal generation. See *Energy Supply*, later, for additional information regarding the Utilities' purchasing strategies.

Generation

NPC continues construction of a 500 MW (nominally rated) natural gas generating station at the existing Harry Allen Generating Station, which is expected to be operational by mid 2011. In 2010, NPC completed construction of Goodsprings, a 7.5 MW (nominally rated) recovered energy generating station, which qualifies as a source of PECs under the Portfolio Standard.

NPC's generation capacity consists of a combination of 46 gas, oil and coal generating units with a combined summer capacity of 4,493 MWs as described in Item 2, *Properties*. In 2010, NPC generated approximately 70.8% of its total system requirements.

SPPC's generation capacity consists of a combination of 19 gas, oil and coal generating units with a combined summer capacity of 1,519 MWs as described in Item 2, *Properties*. In 2010, SPPC generated approximately 59.4% of its total system requirements.

Fuel Sources

The Utilities' 2010 fuel sources for electric generation were provided by natural gas, coal, and oil. The average costs of gas, coal, and oil, including hedging costs, for energy generation per MMBtu for the years 2006 through 2010, along with the percentage contribution to the Utilities' total fuel sources were as follows:

NPC Electric

	Average Consumption Cost & Percentage Contribution to Total Fuel					
	Gas		Coal		Oil	
	$/MMBtu	Percent	$/MMBtu	Percent	$/MMBtu	Percent
2010	5.73	68.5%	2.21	31.5%	17.91	0.0%
2009	5.09	71.8%	2.23	28.2%	10.34	0.0%
2008	7.79	66.5%	2.17	33.5%	18.87	0.0%
2007	6.32	64.4%	1.89	35.6%	17.17	0.0%
2006	7.40	58.8%	1.63	41.1%	16.66	0.1%

For a discussion of the change in fuel costs, see *Results of Operations* in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

2010 was a transition period in which NPC moved from a one season ahead competitive bidding process to a laddering strategy in which physical gas supplies are procured up to three seasons ahead for the time period through the Winter Season 2011-2012 and a four season ahead laddering for the time period starting with Summer Season 2012 through two seasonal competitive bidding processes.

Although NPC has actively requested fixed price physical gas supplies, no such fixed price transactions were executed during 2010. Therefore, the physical gas prices are set at an appropriate industry index during the month of current delivery. All natural gas is delivered to NPC through the use of firm gas transport contracts. Monthly and daily gas supply adjustments are made based on the current energy marketplace and operational considerations.

NPC utilizes a laddered strategy with respect to coal supply and has three long term coal contracts with Arch Coal Company (one expires in 2011 and two expire in 2013) and one with Andalex Resources, Inc. (expires 2011) to supply the Reid Gardner Generating Station. These contracts represent 80% of projected coal requirements for 2011, 40% for 2012 and 20% for 2013. Current sources of coal supply, such as Powder River Basin coal, allow for updated laddering strategies to be applied.

As of December 31, 2010, NPC's Reid Gardner Generating Station coal inventory level was 270,241 tons, or approximately 87 days of consumption at 100% capacity.

A transportation services contract with Union Pacific Railroad Company provides for deliveries from the Provo, Utah interchange, as well as various mines in Utah, Colorado and Wyoming, to the Reid Gardner Generating Station in Moapa, Nevada. The Union Pacific contract has been extended to 2014.

Coal for the Navajo Generating Station, which is jointly owned by several entities and operated by Salt River, is obtained from surface mining operations conducted by Peabody on portions of the Black Mesa in Arizona within the Navajo and Hopi Indian tribes (the Tribes) reservations. The Navajo Generating Station's coal supply contract has been extended to 2019.

Listed below is NPC's transportation portfolio as of December 31, 2010:

Firm Transportation Capacity	Dth per day firm	Term
Forward Haul Capacity - Interstate		
Kern River	50,000	(Apr - Oct)
Kern River	157,208	(Annual)
Backhaul Capacity-Interstate		
Kern River	400,000	(Annual)
Forward Haul Capacity - Intrastate	(LVCo-Gen/Clark/SunRise)	
Southwest Gas LV CoGen 1	5,200	(Jun - Sep)
Southwest Gas LV CoGen 2	45,000	(Annual)
Southwest Gas	288,000	(Annual)

SPPC Electric

	Average Consumption Cost & Percentage Contribution to Total Fuel					
	Gas		Coal		Oil	
	$/MMBtu	Percent	$/MMBtu	Percent	$/MMBtu	Percent
2010	6.54	66.3%	2.32	33.6%	17.10	0.1%
2009	7.98	63.4%	2.12	36.5%	15.91	0.1%
2008	8.95	57.5%	2.09	42.4%	20.90	0.1%
2007	8.34	57.8%	1.93	42.0%	12.10	0.2%
2006	8.92	55.9%	1.83	43.9%	10.15	0.2%

For a discussion of the change in fuel costs, see Results of Operations in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Similar to NPC discussed above, SPPC utilizes a laddering strategy to procure gas. Although SPPC has actively requested fixed price physical gas supplies, no such fixed price transactions were executed during 2010. Therefore, the physical gas prices are set at an appropriate industry index during the month of current delivery. All natural gas is delivered to SPPC through the use of firm gas transport contracts. Monthly and daily gas supply adjustments are made based on the current energy marketplace and operational considerations.

SPPC utilizes a laddered strategy with respect to coal supply and has long-term coal contracts with Black Butte Coal Company and Arch Coal Sales Company that provide for deliveries through December 31, 2015 and December 31, 2011 respectively. These contracts represent 100% of the Valmy Generating Station's projected coal requirements in 2011, 56% for 2012, 43% for 2013, 46% for 2014, and 36% for 2015.

Union Pacific Railroad originates and delivers coal to the Valmy Generating Station. A new contract has been entered into through December 31, 2014 to replace the previous contract that expired on March 31, 2010.

As of December 31, 2010, the coal inventory level at Valmy Generating Station was 265,490 tons or approximately 93 days of consumption at 100% capacity.

SPPC Gas

Growth in all sectors is expected to continue, at a slow pace. SPPC plans its gas infrastructure and supply to serve a demand that would occur if the average of the high and low temperatures for a given day drops to negative five degrees Fahrenheit, which is estimated to be 185,732 Dth per day for the winter of 2010/2011.

To secure gas supplies for power generation and the LDC, SPPC contracted for firm winter, summer, and annual gas supplies with over a dozen Canadian and domestic suppliers. In 2010, seasonal and monthly gas supply net purchases averaged approximately 125,646 Dth per day with the winter period contracts averaging approximately 147,731 Dth per day, and the summer period contracts averaging approximately 110,063 Dth per day.

SPPC's firm natural gas supply is supplemented with natural gas storage services and supplies from the Northwest Pipeline Company facility located at Jackson Prairie in southern Washington. The Jackson Prairie facility can contribute up to a total of 12,687 Dth per day of peaking supplies. In an effort to optimize the value of SPPC's assets, beginning in November of 2010, SPPC entered into a one year agreement whereby the counterparty acquired the rights to the Jackson Prairie storage facility and some of SPPC's gas transport assets during the term of the agreement.

SPPC also has storage on the Paiute Pipeline system. This liquefied gas storage facility provides for an incremental supply of 23,000 Dth per day and is available at any time with two hours notice. Therefore, this storage project supports increases in short term gas supply needs due to unforeseen events such as extreme weather patterns and pipeline interruptions.

Following is a summary of SPPC's transportation and storage portfolio as of December 31, 2010:

Firm Transportation Capacity	Dth per day firm	Term
Northwest	68,696	(Annual)
Paiute	68,696	(November through March)
Paiute	61,044	(April through October)
Paiute	23,000	(LNG tank to Reno/Sparks)
AB Nova	130,319	(Annual)
BC System	128,932	(Annual)
GTN	140,169	(November through April)
GTN	79,899	(May through October)
Tuscarora	172,823	(Annual)
Storage Capacity		
Williams:	281,242	Inventory capability at Jackson Prairie
	12,687	Withdrawal capability per day from Jackson Prairie
Paiute:	303,604	Inventory capability at Paiute LNG
	23,000	LNG Storage

Total LDC Dth supply requirements in 2010 and 2009 were 14.7 million Dth and 15.0 million Dth, respectively. Electric generating fuel requirements for 2010 and 2009 were 29.0 million Dth and 30.9 million Dth, respectively.

Water Supply

NPC and SPPC

Assured supplies of water are important for the Utilities' generating plants, and at the present time, the Utilities have adequate water to meet their generation needs. Reliable water supply is critical to the entire desert southwest region, including the State of Nevada. The newer generation facilities in the Utilities' fleet have been designed to minimize water usage and employ innovative conservation based technologies such as dry cooling and recycled water. Although there are current drought conditions in the Las Vegas area, water resources for most of these facilities rely on regional aquifers and recycled water that are not closely connected to transient drought conditions.

Our water supply rights could be impacted by recent litigation and administrative proceedings before the Nevada State Engineer on remand. On June 17, 2010, the Nevada Supreme Court, in the matter of *Great Basin Water Network v. Taylor,* held that the Nevada State Engineer had failed to act on certain water appropriation applications within the time period set forth by statute and was therefore required to re-notice the water appropriation applications and re-open the protest period. This action resulted in certain permits for use of water being invalidated. Although none of the affected permits are being relied upon by the Utilities, the court's decision did call into question the validity of other permits, including the permits of third parties with whom we have water supply arrangements. Administrative and judicial proceedings continue in this matter and NVE has actively participated in these various proceedings and continues to closely monitor the case. At this time, neither NVE nor the Utilities can predict the outcome of these administrative or judicial proceedings.

Purchased Power

Under the guidelines set forth in the respective ESPs, NPC and SPPC continue to manage a diverse portfolio of contracted and spot market supplies, as well as its own generation resources, with the objective of minimizing its net average system operating costs. During 2010, NPC and SPPC purchased approximately 29% and 41%, respectively, of their total electric energy requirements.

NPC Electric

NPC purchases both forward firm energy and spot market energy based on economics, regulatory requirements, operating reserve margins, and unit availability. NPC seeks to manage its loads efficiently by utilizing its generation resources and long-term purchase power contracts in conjunction with buying and selling opportunities in the market.

NPC has entered into long-term purchase power contracts (3 or more years) with suppliers that generate electricity utilizing gas and renewable resource facilities with a total MW nameplate capacity of 2,418 and contract termination dates ranging from 2013 to 2034. Included in these contracts are 807 MW of nameplate capacity of renewable energy of which approximately 607 MW of nameplate capacity are under development or construction and not currently available. The PECs from renewable resource facilities are used towards compliance with the Portfolio Standard. Energy from some of these contracts is delivered and sold to SPPC through intercompany related purchase power contracts due to the resource location and transmission constraints; however, NPC retains the PEC associated with such contracts. The completion of ON Line, expected in 2013, will give NPC the ability to take delivery of the energy from these contracts.

NPC is a member of the WSPP and the SRSG. NPC's membership in the SRSG has allowed it to network with other utilities in an effort to use its resources more efficiently in the sharing of responsibilities for reserves.

NPC's credit standing may affect the terms under which NPC is able to purchase fuel and electricity in the western energy markets; however, as a result of NPC's improved credit rating over the last several years, this was not a significant factor in 2010.

SPPC Electric

SPPC purchases both forward firm energy and spot market energy based on economics, regulatory requirements, operating reserve margins, and unit availability. SPPC seeks to manage its loads efficiently by utilizing its generation resources and long-term purchase power contracts in conjunction with buying and selling opportunities in the market.

SPPC has entered into long-term purchase power contracts (3 or more years) with suppliers that generate electricity utilizing coal and renewable resource facilities, with a total MW nameplate capacity of 412 and contract termination dates ranging from 2016 to 2039. Included in these contracts are 209 MW of nameplate capacity of renewable energy. The PECs from renewable resource facilities are used towards compliance with the Portfolio Standard. Energy from one of these contracts is delivered and sold to NPC through an intercompany related purchase power contract due to the resource location and transmission constraints; however, SPPC retains the PEC associated with this contract. The completion of ON Line, expected in late 2012, will give SPPC the ability to take delivery of the energy from these contracts.

SPPC is a member of the NWPP and WSPP. These pools have provided SPPC further access to reserves and spot market power, respectively, in the Pacific Northwest and Southwest. In turn, SPPC's generation resources provide a backup source for other pool members who rely heavily on hydroelectric systems.

SPPC's credit standing may affect the terms under which SPPC is able to purchase fuel and electricity in the western energy markets; however, as a result of SPPC's improved credit rating over the last several years, this was not a significant factor in 2010.

Transmission

Electric transmission systems deliver energy from electric generators to distribution systems for final delivery to customers. Transmission systems are designed to move electricity over long distances because generators can be located anywhere from a few miles to hundreds of miles from customers.

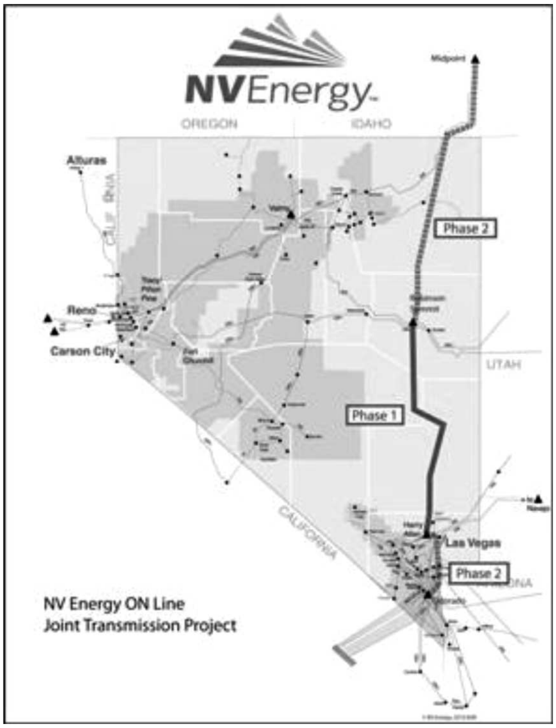
The Utilities' electric transmission systems are part of the Western Interconnection, the regional grid in the west. The Western Interconnection includes the interconnected transmission systems of fourteen western states, two Canadian provinces and the parts of Mexico that make up the Western Electricity Coordinating Council (WECC). WECC is one of eight regional councils of the NERC, the entity responsible for the reliability, adequacy and security of North America's bulk electric system.

NPC's transmission system links generating units within and outside of the NPC Balancing Authority Area to the NPC distribution system. NPC's transmission system is directly interconnected with the transmission systems of Western Area Power Administration, Los Angeles Department of Water and Power, Southern California Edison, and PacifiCorp.

SPPC's transmission system links generating units within the SPPC balancing authority area to the SPPC distribution system. SPPC's transmission system is directly interconnected with the transmission systems of Idaho Power, Los Angeles Department of Water and Power, Southern California Edison, PacifiCorp, Bonneville Power Administration, Pacific Gas & Electric and Plumas-Sierra Rural Electric Cooperative.

The service territories of NPC and SPPC are not currently interconnected; however, in February 2011, NVE and the Utilities entered into an agreement with GBT to construct ON Line, which is expected to be completed in late 2012.

ON Line is a Joint Project between the Utilities and GBT, an affiliate of LS Power. The Joint Project consists of two phases. In Phase 1 of the Joint Project, the parties would complete construction of an initial 500 kV interconnection between the Robinson Summit substation on the SPPC system and the Harry Allen Generating Station on the NPC system by December 31, 2012 (Phase 1 is essentially identical to ON Line or the Utilities' self build option, as discussed under NPC's IRP). Under the Joint Project, the Utilities would own a 25% interest in Phase 1 and enter into a transmission use agreement with GBT for its 75% interest in Phase 1. The Utilities would have rights to 100% of the capacity of Phase 1, which is estimated at approximately 600 MW. NPC would operate and maintain all Phase 1 facilities. In Phase 2, GBT would construct two additional transmission segments at either end of ON Line: one extending from Robinson Summit north to Midpoint, Idaho, and the other commencing at the Harry Allen Generating Station and interconnecting south to the Eldorado substation. GBT would pay for and own 100% of Phase 2 facilities. However, NPC and SPPC would have rights to additional transmission capacity from Midpoint to Eldorado (for a total of approximately 760 MW based on a rating of 2,000 MW for the complete path).



Under the NERC guidelines, the Utilities are Balancing Authorities, Transmission Operators, and Transmission Owners among other roles. As defined by NERC, the Balancing Authority integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time (i.e., the Balancing Authority is responsible for assuring that the demands on the system are matched by an equivalent amount of resources, whether from generators within its area or from imports). The Transmission Operator is responsible for the reliability of its local transmission system, and operates or directs the operations of the transmission facilities. The Transmission Owner owns and maintains transmission facilities. The Utilities also schedule power deliveries over their transmission systems and maintain reliability through their operations and maintenance practices and by verifying that customers are matching loads with resources.

NPC and SPPC plan, build, and operate transmission systems that delivered 20,874,596 MWh and 8,111,005 MWh of electricity to customers, respectively, in their Balancing Authority Areas in 2010. The NPC system handled a system peak load of 5,604 MW in 2010 through approximately 1,724 miles of transmission lines and other transmission facilities ranging from 60 kV to 500 kV. The SPPC system handled a system peak load of 1,611 MW in 2010 through 2,145 miles of transmission lines and other facilities ranging from 60 kV to 345 kV. The Utilities process generation and transmission interconnection requests and requests for transmission service from a variety of customers. These requests usually involve new planning studies and the negotiation of contracts with new and existing customers in this growing system.

Transmission Regulatory Environment

Transmission for the Utilities' bundled retail customers is subject to the jurisdiction of the PUCN for rate making purposes. The Utilities provide cost based wholesale and retail access transmission services under the terms of a FERC approved OATT. In accordance with the OATT, the Utilities offer several transmission services to wholesale customers:

- Long-term and short-term firm point-to-point transmission service (''highest quality'' service with fixed delivery and receipt points),
- Non-firm point-to-point service (''as available'' service with fixed delivery and receipt points), and
- Network transmission service (equivalent to the service NPC provides for NPC's bundled retail customers).

These services are all offered on a nondiscriminatory basis in that all potential customers, including the Utilities, have an equal opportunity to access the transmission system. The Utilities' transmission business is managed and operated independently from the energy marketing business in accordance with FERC's Standards of Conduct.

The Utilities are members of WestConnect and the WestConnect Subregional Transmission Planning Committee. WestConnect is a group of southwest transmission-providing utilities that have agreed to work collaboratively to assess stakeholder and market needs and to investigate, analyze and recommend to its Steering Committee implementation of cost-effective enhancements to the western wholesale electricity market. The Subregional Transmission Planning Committee was established to provide coordinated transmission planning across the WestConnect footprint, including the Southwest Area Transmission Group, in which NPC participates, and the Sierra Subregional Planning Group, in which SPPC participates.

Integrated Resource Plan

The Utilities are required to file IRPs every three years, and as necessary, may file amendments to their IRPs. The IRPs are prepared in compliance with Nevada laws and regulations and cover a 20-year period. The IRPs develop a comprehensive, integrated plan that considers customer energy requirements and propose the resources to meet those requirements in a manner that is consistent with prevailing market fundamentals. The ultimate goal of the IRPs is to balance the objectives of minimizing costs and reducing volatility while reliably meeting the electric needs of NPC's and SPPC's customers. The ESP, discussed in detail later, operates in conjunction with the IRP. It serves as a guide for near-term execution and fulfillment of energy needs.

NPC Electric

In July 2010, the PUCN issued its order on NPC's 2009 IRP, which included the following significant items:

- Approval to jointly develop ON Line with GBT, an affiliate of LS Power, discussed earlier in the *Transmission* section. The PUCN also approved NPC's self-build option for ON Line if the companies and GBT were unable to reach agreement. However, in February 2011, the Utilities and GBT finalized the agreement to jointly construct ON Line.

- Granted NPC's request for critical facility designation for its incremental operating and maintenance costs for ON-Line.
- Approval of NV Energize, as discussed earlier under *Energy Efficiency and Conservation Programs*, of approximately $95 million and $69 million (excluding AFUDC) for NPC and SPPC, respectively, which was contingent on successfully obtaining a grant of $138 million in federal funds from the DOE to co-fund the project. A total grant of $139 million was obtained from the DOE in September 2010.
- Approval to establish a regulatory asset for stranded non-advanced metering infrastructure electric meter costs related to NV Energize.
- Approval of various DSM programs to increase energy efficiency and conservation programs totaling approximately $209.9 million over the three year action plan.
- Accepted NPC's proposal to postpone the EEC indefinitely, but ordered NPC to resubmit the request as a part of its next triennial IRP filing in July 2012. In February 2011, NVE and the Utilities canceled plans to construct the EEC.
- Approval of the long-term load forecast and the three-year forecast.

SPPC Electric

In July 2010, as required by Nevada law, SPPC filed its 2010 triennial IRP with the PUCN. In December 2010, the PUCN issued its order on SPPC's IRP, which included the following significant items:

- Approval of the long-term load forecast and the three-year forecast.
- A finding that the sale of the California assets to CalPeco is in the public interest of Nevada, authorizing and accepting the accounting adjustments and ratemaking treatment proposed by SPPC and authorizing entry into and performing transactions necessary to accomplish the sale of the California assets to CalPeco. The sale of the California assets was completed in January 2011. See Note 16, *Assets Held for Sale*, in the Notes to Financial Statements.
- Authority to modify retirement dates for eleven remote generation facilities and retire and decommission ten remote generation facilities and to accumulate the costs of decommissioning and remediating the remote generation sites in separate regulatory assets subaccounts for recovery in a future GRC proceeding.
- Affirmed the funding level for a transmission project approved in SPPC's 2007 IRP filing of approximately $30 million.
- Approval of DSM programs scopes, budgets, timetables and measures and the Demand Side Plan totaling approximately $36 million.

Energy Supply Planning

General

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. Too great a dependence on generation from the wholesale market can lead to power price volatilities depending on available power supply and prevailing gas prices. 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.

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

1. The PUCN-approved long-term IRP, which is filed every three years, has a twenty-year planning horizon;
2. The PUCN-approved 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 and executing ESPs, management guidelines followed by the Utilities include:

- Maintaining an ESP that minimizes supply costs and retail price volatility and maximizes reliability of supply over the term of the ESP;
- 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; and
- Ensuring transparent and well-documented decisions and execution processes.

In March 2010, and again in December 2010, the PUCN accepted a stipulation among BCP, PUCN staff, and the Utilities in which no additional financial gas hedges will be procured. The Utilities shall continue to monitor its natural gas hedging strategy in light of prevailing market fundamentals and conditions.

Energy Risk Management and Control

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

Intermediate Term ESPs

The Utilities update their intermediate term ESPs annually. In July 2010, SPPC filed its ESP update for the period 2011-2013, and in September 2010, NPC filed its ESP update for the period 2011-2012. Both plans were approved by the EROC and the CEO prior to submission to the PUCN. The ESPs operate within the framework of the PUCN-approved 20-year IRPs and 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 summer needs of 2011 for both SPPC and NPC will be met through a portfolio mix consisting of self-generation, 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 tradeoff between overall fuel and purchased 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.

- Manage credit risk—in a market with some counter-parties that may be in a weak financial condition.
- Procure to meet a needle-peak load profile.
- Manage energy price risk through ongoing intermediate and short-term optimization activities (e.g., optimizing the dispatch of generation, buying heat rate call options for summer capacity, or buying energy from the market).

Long Term Purchased Power Activities

The Utilities update their respective planning documents (IRPs, ESPs, and the Portfolio Standard Annual Report) on a regular and as needed basis to determine their energy and PEC needs. When the planning documents call for energy and/or PECs, RFPs are issued, bids are evaluated, and contracts are executed with the successful bidders. Contracts requiring PUCN approval are submitted to the PUCN as part of the IRP or an amendment to an IRP. Long term purchase power contracts are discussed in more detail earlier, under *Purchased Power*.

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, when possible, 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 overall cost, the projected incremental or decremental cost of the next available generation resource options is compared to the current market to determine the lowest cost option.

Construction Program

The Utilities construction programs and estimated expenditures are subject to continuing review, and are periodically revised to include the rate of load growth, construction costs, availability of fuel types, the number and status of proposed independent generation projects, the need for additional transmission capacity in Nevada, regulatory considerations and impact to customers, the Utilities ability to raise necessary capital, and changes in environmental regulations. Under the Utilities' franchise agreements, they are obligated to provide a safe and reliable source of energy to their customers. Capital construction expenditures and estimates are reflective of the Utilities' obligation to serve their growing customer base.

Construction expenditures for 2010, including AFUDC, net salvage, customer advances and CIAC, were $478.1 million and $140.5 million for NPC and SPPC, respectively, and for the period 2006 through 2010, were $3.8 billion and $1.2 billion, respectively. Estimated construction expenditures for PUCN approved projects, projects under contract, compliance projects and other base capital requirements are as follows (dollars in millions):

	2011	2012-2015	Total 5 - Year
NPC			
Electric Facilities:			
Generation	$138,585	$ 533,426	$ 672,011
Distribution	132,256	372,205	504,461
Transmission	63,566	186,053	249,619
Other	69,838	148,690	218,528
Total	$404,245	$1,240,374	$1,644,619

Total estimated cash requirements related to NPC construction projects consist of the following (dollars in thousands):

	2011	2012-2015	Total 5 - Year
Construction Expenditures	$404,245	$1,240,374	$1,644,619
AFUDC	(20,207)	(66,047)	(86,254)
Net Salvage/ Cost of Removal	7,281	22,263	29,544
Net Customer Advances and CIAC	(35,992)	(110,059)	(146,051)
Total Cash Requirements	$355,327	$1,086,531	$1,441,858

	2011	2012-2015	Total 5 - Year
SPPC			
Electric Facilities:			
Generation	$ 38,987	$215,855	$254,842
Distribution	50,822	240,435	291,257
Transmission	18,750	99,818	118,568
Other	23,963	102,764	126,727
Total	132,522	658,872	791,394
Gas Facilities:			
Distribution	16,119	66,164	82,283
Other	297	1,238	1,535
Total	16,416	67,402	83,818
Common Facilities	18,307	50,094	68,401
Total	$167,245	$776,368	$943,613

Total estimated cash requirements related to SPPC construction projects consist of the following (dollars in thousands):

	2011	2012-2015	Total 5 - Year
Construction Expenditures	$167,245	$776,368	$943,613
AFUDC	(2,549)	(30,283)	(32,832)
Net Salvage/ Cost of Removal	(12,558)	(56,888)	(69,446)
Net Customer Advances and CIAC	(5,817)	(26,353)	(32,170)
Total Cash Requirements	$146,321	$662,844	$809,165

Major PUCN approved projects included in the 5 year estimated construction expenditures are as follows (dollars in thousands):

Projects	Approved by PUCN	Total Cost 2011	Total Project Cost Cash Flows	Cumulative Expenditures as of December 31, 2010	Projected In Service Completion Date Year
Harry Allen Generating Station	$682,367	$54,724	$663,324	$608,600	2011
NV Energize	163,400	62,930	163,400	35,498	2012
ON Line	127,400	45,745	127,400	18,572	2013

In 2008, the PUCN approved the construction of a new 500 MW (nominally rated) natural gas combined cycle electric generating plant at NPC's Harry Allen Generating Station. This facility, 25 miles northeast of Las Vegas, is expected to commence operations by mid 2011.

In 2010, the PUCN approved the NV Energize project. The project is expected to include the deployment of a fully-integrated advanced metering infrastructure, a meter data management system, and a demand response management system. Of the total $303 million dollars in projected costs, $139 million is expected to be provided by the DOE through its Smart Grid Investment Grant Program.

The $163.4 million expected to be provided by the Utilities will be allocated to NPC and SPPC 70% and 30%, respectively.

As discussed earlier in *Transmission*, NVE and the Utilities entered in an agreement with GBT to construct ON Line. As part of the agreement, NVE and the Utilities 25% share in the approximate $509 million project will be approximately $127 million which will be allocated to NPC and SPPC 95% and 5%, respectively.

ENVIRONMENTAL (NVE, NPC AND SPPC)

As with other utilities, NPC and SPPC are subject to various environmental laws and regulations enforced by federal, state and local authorities. The EPA, NDEP and Clark County Department of Air Quality and Environmental Management administer regulations involving air quality, water pollution, solid, and hazardous and toxic waste. Nevada's Utility Environmental Protection Act also requires the Utilities to obtain approval of the PUCN prior to construction of major utility, generation or transmission facilities.

From the beginning phases of siting and development to the ongoing operation of existing or new electric generating, transmission and distribution facilities, our activities involve compliance with diverse laws and regulations which address noise, emissions, impacts to air and water, protected and cultural resources, solid, hazardous, and toxic waste. Our activities often require complex and lengthy processes as we obtain approvals, permits or licenses for new, existing or modified facilities. Additionally, the use and handling of various chemicals or hazardous materials (including wastes) requires release prevention plans and emergency response procedures. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or our operations to ensure complete compliance. The most significant environmental laws and regulations, both in effect and proposed, that could impact NPC and SPPC are discussed below:

Federal Environmental Laws, Regulations and Regulatory Initiatives

Clean Air Standards

The Clean Air Act (CAA) provides a framework for protecting and improving the nation's air quality and controlling mobile and stationary sources of air emissions. The 1990 amendments to the CAA impose limitations on the emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_X) as well as other pollutants. All of the Utilities' fossil fuel generating stations are subject to these limitations and are in compliance with current standards. Congress has from time to time considered legislation that would amend the CAA to target specific emissions from electric utility generating plants. The EPA has also proposed potential regulations associated with these types of emissions. If enacted, this legislation and/or regulations could require reductions in emissions of NO_X, SO_2, mercury and/or other pollutants. The CAA programs which most directly affect NVE's electric generating facilities are described below:

MACT

The federal Clean Air Mercury Rule (CAMR) was an EPA rule based on a national cap-and-trade system which was designed to achieve a 70 percent reduction in mercury emissions and affecting all coal and oil-fired generating units across the country greater than 25 MWs.

In 2008, in State of New Jersey v. EPA, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CAMR as well as a rule delisting Electric Generating Units (EGUs) from hazardous air pollutants (HAPs) requirements. The EPA then signed a consent decree in October of 2009 that requires the agency to propose the Maximum Achievable Control Technology (MACT) rule for coal and oil-fired utility units by March 2011 and issue a final version by November 2011. It is anticipated that the final MACT will specify certain HAPs emission limits, including mercury, based on the average of the top 12% of best performers, as determined through data collection. The Utilities are currently monitoring actual mercury emissions associated with their coal boilers and have conducted testing for other HAPs which was submitted in response to the EPA's data collection request. The Utilities anticipate that once the final rule is released, affected facilities could be required to demonstrate compliance within three to five years.

NAAQS

The CAA requires the EPA to set minimum NAAQS for certain air emissions including ozone, particulate matter, SO_2 and nitrogen dioxide (NO_2). The CAA established two types of NAAQS: (1) primary standards, which set limits to protect public health, and (2) secondary standards, which set limits to protect public welfare. Most NAAQS require measurement over a defined period of time (typically one hour, eight hours, twenty-four hours, or one year) to determine the average concentration of the pollutant present in a defined geographic area.

When a NAAQS has been established, each state must recommend, and the EPA must designate, the areas within its boundaries that meet NAAQS (''attainment areas'') and those that do not (''non-attainment areas''). Each state must develop a state implementation plan (''SIP'') to bring non-attainment areas into compliance with NAAQS and maintain good air quality in attainment areas. The NAAQS that affect or potentially affect our Utility operations are summarized below.

Ozone NAAQS

In March 2008, the EPA issued final rules adopting new, more stringent eight-hour NAAQS for ozone. The EPA lowered the primary and secondary standards from 84 parts per billion to 75 parts per billion. States must submit to the EPA no later than 2014 plans that demonstrate attainment with the standard. Areas must reach attainment by deadlines that vary depending on the severity of the ozone problem.

The EPA announced that it expects to publish the final rule with the new ozone standards by no later than July 31, 2011. The Las Vegas/Clark County region is presently designated as non-attainment and the attainment status of the rest of Nevada will directly depend on the final ozone limit proposed by the EPA.

Particulate Matter NAAQS

The EPA has developed annual NAAQS for coarse particulate matter (defined as particles of 10 micrometers or larger) and both annual and 24-hour NAAQS for fine particulate matter (particles with a size of up to 2.5 micrometers). Nevada counties are currently meeting the standard. However, the EPA is currently reconsidering the annual fine particulate standard, and if lowered as expected, new non-attainment designations in our service territory could occur. The EPA has indicated its reconsideration of the adequacy of the annual fine particulate standard will be completed in October 2011.

SO_2 NAAQS

On June 2, 2010, the EPA established a new one-hour SO_2 NAAQS at 75 parts per billion and revoked the 24 hour and annual SO_2 NAAQS. The EPA expects to designate areas as attainment, non-attainment, or unclassifiable in early 2012 based on the existing monitoring network and modeling. Non-attainment designations are expected to result in lower SO_2 emission limits for sources of SO_2 in or near those areas.

NO_2 NAAQS

On January 22, 2010, the EPA established a new one-hour NAAQS for NO_2 at the level of 100 parts per billion. To determine compliance with the new standard, the EPA is establishing new ambient air monitoring requirements near major roads as well as in other locations where maximum concentrations are expected. Although existing air quality monitors do not currently show exceedances of this new standard in the Utilities' service areas, additional community and roadside monitoring could result in the designation of new non-attainment areas. The EPA intends to re-designate areas as soon as 2016, based on the air quality data from the new monitoring network.

Due to uncertainty regarding the potential stringency of any new NAAQS related proposals, NVE is not able to estimate cost impacts to its generating system at this time. While the final outcome and timing for the EPA's and/or Congressional actions cannot be estimated, the Utilities continue to monitor the development of these standards and assess their potential impact on our generation fleet as new information becomes available.

Regional Haze Rules

In June 2005, the EPA finalized amendments to the July 1999 regional haze rules; thereby requiring states to develop SIPs to demonstrate compliance. These amendments apply to the provisions of the regional haze rule that require emission controls for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. States are required to identify the facilities that will have to reduce emissions through installation of emission controls, known as Best Available Retrofit Technology (BART), and then set emissions limits for those facilities. In 2008, the State of Nevada began its BART rule development and the proposed SIP to implement the BART requirements was released in the first quarter 2009. As presented in the SIP, the impacted BART units are Reid Gardner Generating Station Units 1, 2 & 3; Ft. Churchill Generating Station Units 1 & 2; and Tracy Generating Station Units 1, 2 & 3. The submitted BART SIP contains targeted emission rates and compliance with the state's BART program can be achieved through options such as retrofit of emission reduction equipment on the affected units, or retirement of those units. Nevada's BART SIP is awaiting a final response back from the EPA. The EPA's acceptance of the SIP will then allow NVE to evaluate the economic profile of the impacted units and finalize the technology requirements necessary to meet the target emission rates.

Climate Change

The topic of climate change continues to evolve, and response to this issue brings with it significant environmental, economic and social implications for NVE and other electric utilities. Potential impacts from proposed legislation could vary, depending upon proposed CO_2 emission limits, the timing of implementation of those limits, the method of allocating allowances, the degree to which offsets are allowed and available, and provisions for cost containment measures, such as a safety valve that provides a ceiling price for emission allowance purchases. However, the Utilities' contribution of greenhouse gases amongst its current generation fleet is partly mitigated due to our fuel portfolio being predominately natural gas which emits approximately 50% less CO_2 than coal.

The EPA finalized regulations in September 2009 that require certain categories of businesses, including fossil fuel-fired power plants, to monitor and report their annual greenhouse gas emissions beginning in 2011. NVE has been reporting its annual greenhouse gas emissions since it joined the California Climate Action Registry (CCAR) in 2006. Thus, this new rule covering the reporting of greenhouse gas emissions is not expected to have a material effect on NVE and the Utilities' operations.

After a series of developments and rule proposals, in March of 2010, the EPA affirmed its position that the CAA permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V permit programs are not triggered for a pollutant until a regulatory requirement to control emissions of that pollutant becomes effective. As a result of this EPA determination, new or modified plants that are subject to PSD or Title V programs will have to address greenhouse gas emissions in new permit applications as of January 2011. Similarly, greenhouse gases emitted above certain thresholds from existing plants would be covered under the Title V program beginning in January 2011. Currently, all NVE generation facilities have operating permits that could require modification to comply with the rule if modifications are undertaken. The extent to which this rule could have a material impact on our generating facilities depends upon whether physical changes or change in operations subject to the rule would occur at our generating facilities; future EPA determinations on what constitutes best available control technology for greenhouse gas emissions from power plants; and, whether federal legislation is passed which overrides the rule.

On December 23, 2010, the EPA announced that it will propose first-time greenhouse gas emission standards and guidelines for the power plant sector under the federal CAA. Specifically, the agency expects to propose new source performance standards (NSPS) and emissions guidelines for existing sources for the power plant sector by July 2011, to be finalized in May 2012. It is reasonable to expect that the limits on greenhouse gas emissions imposed by the new source performance standards and guidelines for existing sources will have an impact on generating facility operations. However, until the standards and guidelines are proposed, it is impossible to predict the potential effect on generating facility operations.

The impact on NVE of future initiatives related to greenhouse gas emissions and global climate change remains unknown. Although compliance costs are unlikely to be realized in the near future, federal legislative, federal regulatory, and state and regional-sponsored initiatives to control greenhouse gas emissions continue to progress, making it more likely that some form of greenhouse gas emissions control will eventually be required. Since these initiatives continue to evolve, NVE has and will continue to identify projects that minimize or offset greenhouse gas emissions and believes precautionary actions to limit greenhouse gas emissions are appropriate. Further, NVE continues to employ a three-part strategy to meet the energy needs of Nevada while concurrently reducing its carbon footprint. This strategy includes increasing the Utilities' energy efficiency and conservation programs, and expanding renewable energy initiatives and investments.

Clean Water Act Standards

The EPA administers rules establishing aquatic protection requirements for power generation facilities that withdraw and discharge large quantities of water from and into rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters for cooling purposes. In consideration of the desert environment in which the Utilities operate, none of the Utilities' generation plants employ ''once through'' cooling water intake/discharge structures into public water bodies. Further, all of the Utilities' generation stations are designed to have either minimal or zero water discharge into the surrounding environment. Therefore, the various laws regulating ''once through'' cooling water intake structures and thermal discharges of wastewater from power generation facilities do not specifically apply to the NPC and SPPC generation sites.

The EPA is currently developing revised effluent limitation guidelines and standards for the steam electric power generating industry, which the agency expects to propose in June 2012. The EPA's revision of these guidelines is driven primarily by concern over wastewater discharges from coal-fired power plants, but will also address discharges from ash ponds and flue gas desulfurization air pollution controls. Under the terms of a related court-approved consent decree, the final rules must be published by January 31, 2014. It is reasonable to expect that the new guidelines will impose more stringent limits on wastewater discharges from coal-fired power plants and ash ponds. However, until the revised guidelines are proposed, it is impossible to predict the effect the revised guidelines may have on generating facility operations.

Coal Combustion Product (CCP) Management

In May 2010, the EPA released the text of a proposed rule describing two possible regulatory options it is considering under the Resource Conservation and Recovery Act (RCRA) for the disposal of coal ash generated from the combustion of coal by electric utilities and independent power producers. Under either option, the EPA would regulate the construction of impoundments and landfills, and seek to ensure both the physical and environmental integrity of disposal facilities; however, none of the Utilities' coal facilities currently manage ash in surface water impoundments; rather, these ash products are handled and processed in a dry form at both the Reid Gardner and North Valmy Generating Stations.

The Utilities believe it is possible that the EPA will continue to allow some beneficial use, such as recycling of ash, without classifying it as hazardous waste. However, any additional regulations which more stringently regulate coal ash will likely increase costs for NVE's coal generation facilities if the ability to recycle this material is impaired or current landfill disposal requirements are modified. Due to the uncertainties of how this material may ultimately be regulated in the future, the Utilities are unable to predict the outcome any such regulations might have on their systems at this time.

Remediation Activities

Due to the age and/or historical usage of past and present operating properties, the Utilities may be responsible for various levels of environmental remediation at contaminated sites. This can include properties that are part of ongoing Utility operations, sites formerly owned or used by NVE or the Utilities, and/or sites owned by third parties. The responsibility to remediate typically involves management of contaminated soils and may involve groundwater remediation. Managed in conjunction with relevant federal, state and local agencies, activities vary with site conditions and locations, remedial requirements, complexity and sharing of responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, NVE, the Utilities or their respective affiliates could potentially be held responsible for contamination caused by other parties. In some instances, NVE or the Utilities may share liability associated with contamination with other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. These types of sites/situations are generally managed in the normal course of business operations.

GENERAL - EMPLOYEES (ALL)

NVE and its subsidiaries had 2,916 employees as of January 20, 2011, of which 1,694 were employed by NPC, and 1,113 were employed by SPPC.

NPC and IBEW 396, which covers approximately 57% of NPC's workforce, have signed an agreement to extend the current collective bargaining agreement (CBA) through September 1, 2011. The parties will continue to discuss and negotiate over various topics during the next several months. Until that time, the current contract remains in effect as is.

On August 12, 2010, SPPC and IBEW Local 1245, which covers approximately 59% of SPPC's workforce, entered into a new CBA. The CBA is effective August 16, 2010 for a three-year period ending August 15, 2013.

GENERAL - FRANCHISES (NPC AND SPPC)

The Utilities have non-exclusive local franchises or revocable permits to carry on their business in the localities in which their respective operations are conducted in Nevada. The franchise and other governmental requirements of some of the cities and counties in which the Utilities operate provide for payments based on gross revenues. Public utilities are required by law to collect from their customers a universal energy charge (UEC) based on consumption. The UEC is designed to help those customers who need assistance in paying their utility bills or need help in paying for ways to reduce energy consumption. During 2010, the Utilities collected $136.2 million in franchise or other fees based on gross revenues. They collected $9.6 million in UEC based on consumption. They also paid and recorded as expense $2.3 million of fees based on net profits.

The Utilities will apply for renewal of franchises in a timely manner prior to their respective expiration dates.

ITEM 1A. RISK FACTORS

Risks related to NVE and the Utilities' Results of Operations

Economic conditions could negatively impact our business.

Our operations are affected by local, national and global economic conditions. Moreover, the growth of our business depends in part on continued customer growth and tourism demand in our service areas. The consequences of recent national recession and continuing local recession have included a lower level of economic activity and uncertainty within the capital and commodity markets, including availability and cost of credit, inflation rates, monetary policy, unemployment rates and legislative and regulatory uncertainty. A lower level of economic activity, changes in discretionary spending, conservation efforts by our customers, and decreased tourism activity in our service areas have resulted in a decline in energy consumption, which has and may continue to affect our future growth. Instability in the financial markets, as a result of the current recession or otherwise, also may affect the cost of capital and our ability to raise capital.

Current economic conditions have and may continue to lead to potential increased unemployment, which may impact customers' ability to pay on a timely basis, increase customer bankruptcies, and lead to increased bad debt. It is expected that commercial and industrial customers will be impacted first with residential customers following, if such circumstances occur.

Our operating results will likely fluctuate on a seasonal and quarterly basis.

Electric power generation is generally a seasonal business. In many parts of the country, including our service areas, demand for power peaks during the hot summer months, with market prices also peaking at that time. As a result, our operating results in the future will likely fluctuate substantially on a seasonal basis. In addition, we have historically sold less power, and consequently earned less income, when weather conditions in our service areas are milder. Unusually mild weather in the future could diminish our results of operations and harm our financial condition.

Changes in consumer preferences, current local recessionary environment, war, and the threat of terrorism or pandemics may harm our future growth and operating results.

Changes in consumer preferences or discretionary consumer spending in the Las Vegas portion of our service area could continue to harm our business. We cannot predict the extent to which the current local recessionary environment, future terrorist and war activities, or pandemics, in the U.S. and elsewhere may affect us, directly or indirectly. An extended period of reduced discretionary spending and/or disruptions or declines in airline and other travel and business conventions could significantly harm the businesses in and the continued growth of the Las Vegas portion of our service area, which could harm our business and results of operations.

Risks related to NVE and the Utilities' Regulatory Proceedings

If the Utilities do not receive favorable rulings in their future GRCs or other regulatory filings, including revenue recovery programs relating to the EEIR, such events may have a significant adverse effect on our financial condition, cash flows and future results of operations.

The Utilities' revenues and earnings are subject to change as a result of regulatory proceedings known as GRCs, which the Utilities file with the PUCN approximately every three years. In the Utilities' GRCs, the PUCN establishes, among other things, their recoverable rate base, their ROE, overall ROR, depreciation rates and their cost of capital.

For a discussion of NPC's and SPPC's recent GRCs, see Note 3, *Regulatory Actions* of the Notes to Financial Statements.

We cannot predict what the PUCN will direct in their orders on the Utilities' future GRCs or other regulatory filings, including revenue recovery programs relating to the EEIR. Inadequate BTGR would have a significant adverse effect on the Utilities' financial condition and future results of operations and could cause downgrades of their securities by the rating agencies and make it significantly more difficult or expensive to finance operations and construction projects and to buy fuel, natural gas and purchased power from third parties.

If the Utilities do not receive favorable rulings in the deferred energy applications that they file with the PUCN and they are unable to recover their deferred purchased power, natural gas and fuel costs, including changes in prices due to temporary suspension of hedging programs, they will experience an adverse impact on cash flow and earnings. Any significant disallowance of deferred energy charges in the future could materially adversely affect their cash flow, financial condition and liquidity.

Under Nevada law, purchased power, natural gas and fuel costs in excess of those included in base rates are deferred as an asset on the Utilities' balance sheets and are not shown as an expense until recovered from their retail customers. The Utilities are required to file DEAA applications with the PUCN at least once every twelve months so that the PUCN may verify the prudence of the energy costs. Nevada law also requires the PUCN to act on these cases within a specified time period. Any of these costs determined by the PUCN to have been imprudently incurred cannot be recovered from the Utilities' customers. Past disallowances in the Utilities' deferred energy cases have been significant, which resulted in ratings downgrades of our debt securities and adversely affected our liquidity and access to capital markets.

For a discussion of NPC's and SPPC's recent and pending deferred energy rate cases, see Note 3, Regulatory Actions of the Notes to Financial Statements.

Material disallowances of deferred energy costs, gas costs or inadequate BTERs would have a significant adverse effect on the Utilities' financial condition and future results of operations, could cause downgrades of NVE's and the Utilities' securities by the rating agencies and could make it more difficult or expensive to finance operations and construction projects and buy fuel, natural gas and purchased power from third parties.

The Utilities purchase a portion of the power that they sell to their customers from power suppliers. If the Utilities' and/or their power suppliers' credit ratings are downgraded, the Utilities may experience difficulty entering into new power supply contracts, and to the extent that they must rely on the spot market, they may experience difficulty obtaining such power from suppliers in the spot market in light of their financial condition, or the financial condition of their power suppliers. In addition, if the Utilities experience unexpected failures or outages in their generation facilities, they may need to purchase a greater portion of the power they provide to their customers. If access to liquidity is limited to obtain their power requirements, particularly for NPC at the onset of the summer months, and are unable to obtain power through other means, their business, operations and financial condition will be materially adversely affected.

If the Utilities cannot maintain the required level of renewable energy or procure sufficient solar energy to meet Nevada's increasing Portfolio Standard the PUCN may, among other things, impose an administrative fine for noncompliance.

Nevada law sets forth the Portfolio Standard requiring providers of electric service to acquire, generate, or save from renewable energy systems or energy efficiency measures a specific percentage of its total retail energy sales from renewable energy sources, including biomass, geothermal, solar, waterpower, wind, and recovered energy generation projects. In 2010 the Utilities were required to obtain an amount of PECs equivalent to 12% of their total retail energy from renewables. The Portfolio Standard increases to 15% for 2011 and 2012, to 18% for 2013 and 2014, and reaches 20% in 2015, after which it increases again to 22% for the years 2020 through 2024, and to 25% for 2025 and beyond. Moreover, not less than 5% of the total Portfolio Standard must be met from solar resources until 2016, when a minimum of 6% must be solar. In the event the Utilities do not fully meet the standard in a given year, if the PUCN does not exempt them, they will be required to make up the PEC deficiency in subsequent years.

Due to periodic increases in the Portfolio Standard and increasing retail sales, the Utilities must acquire increasing amounts of renewable energy. The Utilities' success in meeting the increasing Portfolio Standard remains largely dependent on their ability to acquire additional renewable energy from either self-owned renewable generation facilities or the purchase of renewable energy from third-party developers or other utilities and through qualified conservation and energy efficiency measures. In 2010, the PUCN issued an order allowing NPC to offset its 2009 credit shortfall with credits earned in 2010 and a loan of surplus credits from SPPC.

The Utilities' ability to access the capital markets is dependent on their ability to obtain regulatory approval to do so.

The Utilities will need to continue to support working capital and capital expenditures, and to refinance maturing debt, through external financing. The Utilities must obtain regulatory approval in Nevada in order to borrow money or to issue securities and are therefore dependent on the PUCN to issue favorable orders in a timely manner to permit them to finance their operations, construction and acquisition costs and to purchase power and fuel necessary to serve their customers. On October 14, 2010, the PUCN issued an order authorizing NPC to restate and utilize its available authority to issue up to $725 million of additional long-term debt securities; to refinance up to approximately $672.5 million of long-term debt securities, said authority to expire on December 31, 2013; and ongoing authority to maintain a revolving credit facility of up to $1.3 billion. On October 28, 2009, the PUCN approved financing authority for SPPC to issue up to $350 million of long-term debt securities over a three-year period ending December 31, 2012; ongoing authority to maintain a revolving credit facility of up to $600 million; and authority to refinance up to approximately $348 million of long-term debt securities. However, we cannot assure you that in the future the PUCN will issue such favorable orders or that such favorable orders will be issued on a timely basis.

Risks related to NVE and the Utilities' Environmental Matters

If Federal and/or State requirements are imposed on the Utilities mandating further emission reductions, including greenhouse gases and other pollutants, or if national ambient air quality standards are modified, such requirements could make some electric generating units uneconomical to maintain or operate.

Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. Certain Congressional leaders, environmental advocacy groups and regulatory agencies in the United States have also been focusing considerable attention on CO_2 emissions from power generation facilities and their potential role in climate change and/or regional air quality compliance. Moreover, there are many legislative and rulemaking initiatives pending at the federal and state level that are aimed at the reduction of fossil plant emissions, as well as modification of the NAAQS for ozone and other pollutants. We cannot predict the outcome of pending or future legislative and rulemaking proposals. Future changes in environmental laws or regulations governing emissions reductions could make certain electric generating units, especially those utilizing coal for fuel, uneconomical to construct, maintain or operate or could require design changes or the adoption of new technologies that could significantly increase costs or delay in-service dates. In addition, any legal obligation that would require the Utilities to substantially reduce their emissions beyond present levels could require extensive mitigation efforts and, in the case of CO_2 legislation or regulation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities.

The Utilities are subject to numerous environmental laws and regulations that may increase our cost of operations, impact or limit our business plans, expose us to environmental liabilities, or make some electric generating units uneconomical to maintain or operate.

The Utilities are subject to extensive federal, state and local laws and regulations relating to environmental protection. These laws and regulations can result in increased capital, construction, operating, and other costs. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals, and may be enforced by both public officials and private individuals. We cannot predict the outcome or effect of any action or litigation that may arise from applicable environmental regulations.

In addition, either of the Utilities may be identified as a responsible party for environmental cleanup by environmental agencies or regulatory bodies. We cannot predict with certainty the amount or timing of future expenditures related to environmental matters because of the difficulty of estimating clean up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Environmental regulations may also require us to install pollution control equipment at, or perform environmental remediation on, our facilities.

Existing environmental regulations regarding air emissions (such as NO_X, SO_2 or mercury emissions), water quality and other toxic pollutants may be revised or new climate change laws or regulations may be adopted or become applicable to us. Revised or additional laws or regulations, which may result in increased compliance costs, including the adoption of new technologies or additional operating restrictions, could have a material adverse effect on our financial condition and results of operations particularly if those costs are not fully recoverable from our customers.

Furthermore, we may not be able to obtain or maintain all environmental regulatory approvals necessary to our business. If there is a delay in obtaining any required environmental regulatory approval or if we fail to obtain, maintain or comply with any such approval, operations at our affected facilities could be delayed, halted or subjected to additional costs.

Risks related to NVE and the Utilities' Liquidity and Capital Resources

The Utilities plan to make capital expenditures to complete construction of generation and transmission facilities. In addition, the Utilities require liquidity to bridge the cost of fuel and purchased power and other operating activities until recovered through rates. If we are unable to finance such construction or limit the amount of capital expenditures associated with those facilities to forecasted levels, finance or generate sufficient liquidity for fuel and purchased power including, risk management activities, and/or recover amounts spent on construction, fuel and purchased power and other operating activities through future filings with the PUCN, and/or maintain our credit ratings, our financial condition and results of operation could be adversely affected.

Our long term business objectives include plans to complete the construction of generation and transmission facilities. Significant construction capital requirements and liquidity to bridge the cost of fuel and purchased power and other operating activities, until recovered through rates, require that the Utilities may finance through additional borrowings under the Utilities' respective credit facilities, through additional debt financings in private or public offerings or through debt or equity financings by NVE. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*, Liquidity and Capital Resources, NVE. Currently, access to the capital markets is not a limiting factor; however, if significant new capital requirements are requested and approved, we cannot be sure that we will be able to obtain financing on favorable terms, or at all, since the availability and terms of financing depend on financial market conditions, including the effect of volatility in financial and credit markets, changes in availability and cost of capital either due to market conditions or as a result of the Utilities' credit ratings, or interest rate fluctuations. Neither can we be sure that we will be successful in limiting capital expenditures to planned amounts, particularly in the event of escalating costs for materials, labor and environmental compliance, timing delays and other economic factors. If we cannot obtain favorable financing arrangements for our planned capital expenditures, limit such capital expenditures to forecasted amounts, finance or generate sufficient liquidity for fuel and purchased power, including risk management activities and other operating costs, and/or recover or timely recover amounts spent on construction, fuel and purchased power and other operating activities through future filings with the PUCN, and/or maintain our credit ratings, our financial condition and results of operations could be adversely affected.

Lower than expected investment returns on pension and other postretirement plan assets and other factors may increase NVE's pension and other postretirement plan liability and funding requirements.

Substantially all of NVE employees are covered by a single employer defined benefit pension and other postretirement plan. At present, the pension and other postretirement plan is underfunded in that the projected benefit obligations exceed the aggregate fair value of plan assets. The funded status of the plan can be affected by contributions to plan assets, plan design, investment returns on plan assets, discount rates, mortality rates of plan participants, pension reform legislation and a number of other factors. There can be no assurance that the value of NVE's pension and other postretirement plan assets will be sufficient to cover future liabilities. Although NVE has made significant contributions to its pension and other postretirement plan in recent years, it is possible that NVE could incur a significant pension and other postretirement liability adjustment, or could be required to make significant additional cash contributions to its plan, which would reduce the cash available for operating activities, and have a material impact on earnings. Refer to Note 11, *Retirement Plan and Post-Retirement Benefits* of the Notes to Financial Statements.

The Utilities are subject to fuel and wholesale electricity pricing risks, which could result in unanticipated liabilities and cash flow requirements or increased volatility in our earnings, and to related credit and liquidity risks.

The Utilities' business and operations are subject to changes in purchased power prices and fuel costs that may cause increases in the amounts they must pay for power supplies on the wholesale market and the cost of producing power in their generation plants. Prices for electricity, fuel and natural gas may fluctuate substantially over relatively short periods of time and expose the Utilities to significant commodity price risks. Among the factors that could affect market prices for electricity and fuel are:

- prevailing market prices for coal, oil, natural gas and other fuels used in generation plants, including associated transportation costs, and supplies of such commodities;
- changes in the regulatory framework for the commodities markets that they rely on for purchased power and fuel;
- liquidity in the general wholesale electricity market;
- the actions of external parties, such as the FERC or independent system operators, that may impose price limitations and other mechanisms to address volatility in the western energy markets;
- weather conditions impacting demand for electricity or availability of hydroelectric power or fuel supplies;
- union and labor relations;
- natural disasters, wars, acts of terrorism, embargoes and other catastrophic events; and
- changes in federal and state energy and environmental laws and regulations.

Effective October 2009, the Utilities' hedging programs were suspended; therefore, fluctuating commodity prices could have a material adverse effect on their cash flows and their ability to operate and, consequently, on our financial condition.

Increasing energy commodity prices, particularly with respect to natural gas, have a significant effect on our short-term liquidity. Although the Utilities are entitled to recover their prudently incurred power, natural gas and fuel costs through deferred energy rate case filings with the PUCN, if current commodity prices increase, the Utilities' deferred energy balances will increase, which will negatively affect our cash flow and liquidity until such costs are recovered from customers.

The Utilities are also subject to credit risk for losses that they incur as a result of non-performance by counterparties of their contractual obligations to deliver fuel, purchased power, natural gas (for resale) or settlement payments. The Utilities often extend credit to counterparties and customers and they are exposed to the risk that they may not be able to collect amounts owed to them. Credit risk includes the risk that a counterparty may default due to circumstances relating directly to it, and also the risk that a counterparty may default due to circumstances that relate to other market participants that have a direct or indirect relationship with such counterparty. Should a counterparty, customer or supplier fail to perform, the Utilities may be required to replace existing contracts with contracts at then-current market prices or to honor the underlying commitment.

The Utilities are also subject to liquidity risk resulting from the exposure that their counterparties perceive with respect to the possible non-performance by the Utilities of their physical and financial obligations under their energy, fuel and natural gas contracts. These counterparties may under certain circumstances, pursuant to the Utilities' agreements with them, seek assurances of performance from the Utilities in the form of letters of credit, prepayment or cash deposits, or reduce availability under the Utilities' revolving credit facilities for negative mark-to-market positions. In periods of price volatility, the Utilities' exposure levels can change significantly, which could have a significant negative impact on our liquidity and earnings. In the event the Utilities' credit ratings are downgraded below investment grade, the maximum amount of collateral the Utilities would be required to post is approximately $30.7 million. Additionally, the Utilities shall reduce their availability under their revolving credit facilities for negative mark-to-market positions on hedging contracts with counterparties who are lenders under the revolving credit facilities provided that the reduction of availability under the revolving credit facilities shall at no time exceed 50% of the total commitments then in effect under the credit facilities. The calculation of NPC's and SPPC's negative mark-to-market exposure as of November 30, 2010 was approximately $28.3 million and $13.8 million, respectively, which amount was in effect for borrowings during the month of December 2010. Currently, the Utilities only have hedging contracts with counterparties who are also lenders on the revolving credit facilities; however, future contracts entered into with non-lenders may require the Utilities to post cash collateral in the event of a credit rating downgrade.

As of February 23, 2011, NPC had approximately $569.6 million available under its $600 million revolving credit facility and SPPC has approximately $230.9 million available under its $250 million revolving credit facility, which includes reductions for hedging transactions and letters of credits.

If NVE is precluded from receiving dividends from the Utilities, its financial condition, and its ability to meet its debt service obligations, pay dividends and make capital contributions to its subsidiaries, will be materially adversely affected.

Since NVE is a holding company, substantially all of its cash flow is provided by dividends paid to NVE by NPC and SPPC on their common stock, all of which is owned by NVE. 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 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. As a result of the Utilities' credit rating on their senior secured debt at investment grade by S&P and Moody's, these restrictions are suspended and no longer in effect so long as the debt remains investment grade by both rating agencies. 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 NVE could be jeopardized.

We cannot assure investors that future dividend payments on our Common Stock will be made or, if made, in what amounts they may be paid.

Dividends are considered periodically by NVE's BOD and are subject to factors that ordinarily affect dividend policy, such as current and prospective financial condition, earnings and liquidity, prospective business conditions, regulatory factors, and dividend restrictions in NVE's and the Utilities' financing agreements. The BOD will continue to review these factors on a periodic basis to determine if and when it would be prudent to declare a dividend on NVE's Common Stock; however, there is no guarantee that dividends will be paid in the future, or that, if paid, the dividends will be paid in the same amount or with the same frequency as in the past.

NVE's indebtedness is effectively subordinated to the liabilities of its subsidiaries, particularly NPC and SPPC. NVE and the Utilities have the ability to issue a significant amount of additional indebtedness under the terms of their various financing agreements.

Because NVE is a holding company, its indebtedness is effectively subordinated to the Utilities' existing indebtedness and other future liabilities, including claims by the Utilities' trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. NVE conducts substantially all of its operations through its subsidiaries, and thus NVE's ability to meet its obligations under its indebtedness and to pay any dividends on its common stock will be dependent on the earnings and cash flows of those subsidiaries and the ability of those subsidiaries to pay dividends or to advance or repay funds to NVE. As of December 31, 2010, the Utilities had approximately $4.8 billion of debt outstanding. The terms of NVE's indebtedness restrict the amount of additional indebtedness that NVE and the Utilities may issue. Based on NVE's December 31, 2010 financial statements, assuming an interest rate of 7%, NVE's indebtedness restrictions would allow NVE and the Utilities to issue up to approximately $1.9 billion of additional indebtedness in the aggregate, unless the indebtedness being issued is specifically permitted under the terms of NVE's indebtedness. In addition, NPC and SPPC are subject to restrictions under the terms of their various financing agreements on their ability to issue additional indebtedness.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Substantially all of NPC's and SPPC's property in Nevada is subject to the lien of the General and Refunding Mortgage Indentures dated as of May 1, 2001, between NPC and SPPC, respectively, and The Bank of New York Mellon Trust Company, N.A., as trustee, as amended and supplemented.

The following is a list of NPC's share of electric generation plants including the type and fuel used to generate, the anticipated 2011 net capacity (MW), and the years that the units were installed.

Plant Name	Type	Fuel	Number of Units	Summer MW Capacity	Commercial Operation Year
Clark Generating Station(1)	Combined Cycle	Gas	6	430	1979, 1979, 1980, 1982, 1993, 1994
	Gas	Gas	1	54	1973
	Peakers	Gas	12	619	2008
Sunrise	Steam	Gas	1	80	1964
	Gas	Gas	1	70	1974
Harry Allen Generating Station	Combined Cycle	Gas	3	484	2011
	Gas	Gas	2	144	1995, 2006
Lenzie Generating Station(2)	Combined Cycle	Gas	6	1,102	2006
Silverhawk Generating Station(3)	Combined Cycle	Gas	3	395	2004
Higgins Generating Station	Combined Cycle	Gas	3	530	2004
Mohave Generating Station(4)(5)	Steam	Coal	0	0	1971
Navajo Generating Station(6)	Steam	Coal	3	255	1974, 1975, 1976
Reid Gardner Generating Station(7)	Steam	Coal	4	325	1965, 1968, 1976, 1983
Goodsprings	Waste Heat		1	5	2010
Total			46	4,493	

(1) The two combined cycles at Clark Generating Station each consist of two gas turbines, two Heat Recovery Steam Generators (HRSG), and one steam turbine. In 1993 and 1994, the original four gas turbines (1979-1982) were combined with four new HRSGs and two new steam turbines to form the combined cycles. Capacity of the Clark Peakers is derated due to low gas delivery pressure in the winter period.

(2) The two combined cycles at the Lenzie Generating Station each consist of two gas turbines, two HRSGs and one steam turbine.

(3) The acquisition of a 75% ownership interest in the Silverhawk Generating Station from Pinnacle West was consummated in 2006. SNWA continues to hold a 25% ownership interest in the plant. The combined cycle plant consists of two gas turbines, two HRSGs and one steam turbine.

(4) Per a 1999 Consent Decree, Mohave Generating Station ceased operation on December 31, 2005. The PUCN approved establishing regulatory accounts related to the shutdown and decommissioning. See Note 3, *Regulatory Actions*, of the Notes to Financial Statements for further discussion.

(5) Prior to the shut down, the total summer net capacity of the Mohave Generating Station was 1,580 MW. Southern California Edison is the operating agent and NPC has a 14% interest in the Mohave Generating Station.

(6) NPC has an 11.3% interest in the Navajo Generating Station. The total capacity of the Navajo Generating Station is 2,250 MW. Salt River is the operator (21.7% interest). There are four other partners: U.S. Bureau of Reclamation (24.3% interest), Los Angeles Dept. of Water & Power (21.2% interest), Arizona Public Service Co. (14% interest), and Tucson Electric Power (7.5% interest).

(7) Reid Gardner Generating Station Unit No. 4 is co-owned by the CDWR (67.8%) and NPC (32.2%); NPC is the operating agent. NPC is entitled to 25 MW of base load capacity and 232 MW of peaking capacity from that Unit, subject to the following limitations: 1,500 hours/year, 300 hours/month, and 8 hours/day. The total summer net capacity of the Unit, subject to heat input limitation, is 257 MW. Reid Gardner Generating Station Units 1, 2, and 3, subject to heat input limitations, have a combined net capacity of the Station is 300 MW. The Reid Gardner Generating Station summer capacity is 557 MW. The agreement with CDWR terminates upon final settlement in 2013, at which time NPC assumes 100% ownership.

The following is a list of SPPC's share of electric generation plants including the type and fuel used to generate, the anticipated 2011 net capacity (MW), and the years that the units became operational.

Plant Name	Type	Fuel	Number of Units	Summer MW Capacity	Commercial Operation Year
Ft. Churchill Generating Station	Steam	Gas/Oil	2	226	1968, 1971
Tracy Generating Station	Steam	Gas/Oil	3	244	1963, 1965, 1974
Tracy Generating Station 4&5[(1)]	Combined Cycle	Gas	2	104	1996, 1996
Tracy Generating Station[(2)]	Combined Cycle	Gas	3	541	2008
Clark Mtn. CT's	Gas	Gas/Oil	2	132	1994, 1994
Valmy Generating Station[(3)]	Steam	Coal	2	261	1981, 1985
Other[(4)]	Gas, Diesels	Propane, Oil	5	11	1960-1970
Total			19	1,519	

(1) The combined cycle consists of one combustion turbine, one HRSG, and one steam turbine. In 2003, SPPC installed duct burners, which added 15 MW of capacity.

(2) A new combined cycle at Tracy Generating Station consists of 2 gas turbines, 2 HRSGs and 1 steam turbine. It became operational in 2008.

(3) Valmy Generating Station is co-owned by Idaho Power Company (50%) and SPPC (50%); SPPC is the operator. Valmy Generating Station has a total net capacity of 522 MW.

(4) In 2011, it is anticipated there will be 5 diesel units included in the "Other" category. In 2010, there were 21 units in "Other", but 16 are in the process of being retired, or sold, and are not included as available capacity.

ITEM 3. LEGAL PROCEEDINGS

NPC and SPPC

Western United States Energy Crisis Proceedings before the FERC

FERC 206 complaints

In December 2001, the Utilities filed ten complaints with the FERC against various power suppliers, including Enron, under Section 206 of the Federal Power Act seeking price reduction of forward wholesale power purchase contracts entered into prior to the FERC mandated price caps imposed in

June 2001 in reaction to the Western United States Energy Crisis. The Utilities contested the amounts paid for power actually delivered as well as termination claims for undelivered power against terminating suppliers.

Over the course of the last ten years, the Utilities litigated and settled the termination claims with the various power suppliers. The Utilities had previously negotiated settlements with Duke Energy Trading and Marketing, Morgan Stanley Capital Group, El Paso Merchant Energy, now known as El Paso Marketing L.P., Calpine Energy Services and Enron. The Utilities completed bilateral settlement discussions with Allegheny Energy Supply Company (Allegheny), American Electric Power Service Corporation (AEP) and BP Energy in 2009 and 2010. The Utilities, together with other interested parties including the BCP, settled and resolved all claims against BP Energy, AEP and Allegheny, each for an immaterial amount in return for a release of all claims by the Utilities and BCP. The settlement agreement with Allegheny received final approval by the FERC in January 2011. With the final approval of the Allegheny Settlement by FERC, all of the Utilities' FERC 206 complaints are settled and resolved.

Other Legal Matters

NVE and its subsidiaries, through the course of their normal business operations, are currently involved in a number of other legal actions, none of which has had or, in the opinion of management, is expected to have a significant impact on their financial positions or results of operations. See Note 13, *Commitments and Contingencies* in the Notes to Financial Statements for further discussion of other legal matters.

ITEM 4. [REMOVED AND RESERVED]

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES (NVE)

NVE's Common Stock is traded on the New York Stock Exchange (symbol NVE). Dividends paid per share and high and low sale prices of the Common Stock as reported for 2010 and 2009 are as follows:

	Dividends declared per share		2010		2009	
	2010	2009	High	Low	High	Low
First Quarter	$0.11	$0.10	$12.75	$10.94	$11.15	$ 7.96
Second Quarter	0.11	0.10	13.14	11.18	11.17	9.27
Third Quarter	0.11	0.10	13.30	11.53	12.49	10.52
Fourth Quarter	0.12	0.11	14.40	12.75	12.75	11.19

Number of Security Holders:

Title of Class	Number of Record Holders
Common Stock: $1.00 Par Value	As of February 21, 2011: 14,311

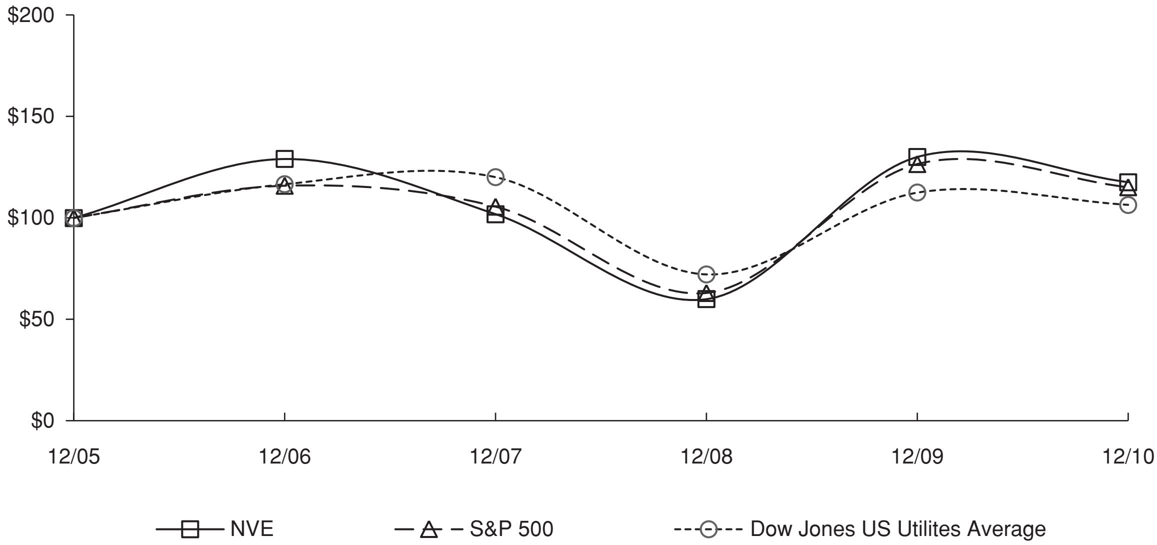
Dividends are considered periodically by the BOD and are subject to factors that ordinarily affect dividend policy, such as current and prospective earnings, current and prospective business conditions, regulatory factors, NVE's financial condition and other matters within the discretion of the BOD, as well as dividend restrictions set forth in 6.75% Senior Notes due 2017 and 6.25% Senior Notes due 2020.

On February 3, 2011, NVE's BOD declared a quarterly cash dividend of $0.12 per share payable on March 16, 2011 to common shareholders of record on March 1, 2011.

There is no guarantee that NVE will continue to pay dividends in the future, or that the dividends will be paid at the same amount or with the same frequency. See Note 8, *Debt Covenant and Other Restrictions* of the Notes to Financial Statements, for a description of the restrictions on NPC's and SPPC's ability to pay dividends to NVE and on NVE's ability to pay dividends on its common stock.

For information on the equity compensation plans, see Item 12.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among NV Energy, The S&P 500 Index
And The Dow Jones US Utilities Average Index



ITEM 6. SELECTED FINANCIAL DATA

See Item 7, *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 NVE, NPC and SPPC (dollars in thousands, except per share amounts):

NVE

	Year ended December 31,				
	2010	2009	2008	2007	2006[2]
Operating Revenues	$ 3,280,222	$ 3,585,798	$ 3,528,113	$3,600,960	$3,355,950
Operating Income	$ 644,435	$ 564,083	$ 552,079	$ 489,722	$ 580,368
Net Income	$ 226,984	$ 182,936	$ 208,887	$ 197,295	$ 277,451
Net Income Per Average Common Share - Basic and	$ 0.97	$ 0.78	$ 0.89	$ 0.89	$ 1.33
- Diluted	$ 0.96	$ 0.78	$ 0.89	$ 0.89	$ 1.33
Total Assets	$11,669,668	$11,413,463	$11,347,870[1]	$9,468,119	$8,832,076
Long-Term Debt (not including current maturities)	$ 4,924,109	$ 5,303,357	$ 5,266,982	$4,137,864	$4,001,542
Dividends Declared Per Common Share	$ 0.45	$ 0.41	$ 0.34	$ 0.16	$ -

(1) Total assets increased significantly in 2008 primarily due to an increase in plant in service as a result of NPC's acquisition of the Higgins Generating Station, the completion of the Clark Peaking Units by NPC and the completion of the Tracy Generating Station by SPPC. Also contributing to the increase was an increase in Regulatory Assets and Regulatory Assets for Pensions.

(2) Income for the year ended December 31, 2006 includes reinstatement of deferred energy of approximately $116.2 million net of taxes and a $40.9 million net of taxes gain on the sale of Tuscarora Gas Pipeline Company's partnership interest in Tuscarora Gas Transmission Company.

NPC

	Year ended December 31,				
	2010	2009	2008	2007	2006[2]
Operating Revenues	$2,252,377	$2,423,377	$2,315,427	$2,356,620	$2,124,081
Operating Income	$ 467,412	$ 396,362	$ 369,966	$ 358,412	$ 443,053
Net Income	$ 185,943	$ 134,284	$ 151,431	$ 165,694	$ 224,540
Total Assets	$8,301,824	$8,096,371	$7,904,147[1]	$6,377,369	$5,987,515
Long-Term Debt (not including current maturities)	$3,221,833	$3,535,440	$3,385,106	$2,528,141	$2,380,139
Dividends Declared - Common Stock	$ 74,000	$ 112,000	$ 44,000	$ 25,667	$ 48,917

(1) Total assets increased significantly in 2008 primarily due to an increase in plant in service as a result of NPC's acquisition of the Higgins Generating Station, the completion of the Clark Peaking Units by NPC. Also contributing to the increase was an increase in Regulatory Assets and Regulatory Assets for Pensions.

(2) Income from continuing operations, for the year ended December 31, 2006 includes reinstatement of deferred energy of approximately $116.2 million net of taxes.

SPPC

	Year ended December 31,				
	2010	2009	2008	2007	2006
Operating Revenues	$1,027,822	$1,162,393	$1,212,661	$1,244,297	$1,230,230
Operating Income	$ 180,995	$ 170,589	$ 185,959	$ 135,948	$ 143,587
Net Income	$ 72,375	$ 73,085	$ 90,582	$ 65,667	$ 57,709
Total Assets	$3,347,022	$3,342,145	$3,464,435[1]	$2,979,893	$2,807,837
Long-Term Debt (not including current maturities)	$1,195,775	$1,282,225	$1,395,987	$1,084,550	$1,070,858
Dividends Declared - Common Stock	$ 108,000	$ 32,000	$ 233,000	$ 12,833	$ 24,619
Dividends Declared - Preferred Stock	$ -	$ -	$ -	$ -	$ 975

(1) Total assets increased significantly in 2008 primarily due to an increase in plant in service as a result of the completion of the Tracy Generating Station. Also contributing to the increase was an increase in Regulatory Assets and Regulatory Assets for Pensions.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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," "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 NVE, NPC or SPPC; (NPC and SPPC are collectively referred to as the Utilities) to differ materially from those contemplated in any forward-looking statement include, among others, the following:

(1) economic conditions both nationwide and regionally, including availability and cost of credit, inflation rates, monetary policy, unemployment rates, customer bankruptcies, including major gaming customers with significant debt maturities, weaker housing markets, a decrease in tourism, particularly in Southern Nevada, and cancelled or deferred hotel construction projects, each of which affect customer growth, customer collections, customer demand and usage patterns;

(2) changes in the rate of industrial, commercial and residential growth in the service territories of the Utilities, including the effect of weaker housing markets, increased unemployment and energy conservation programs, which could affect the Utilities' ability to accurately forecast electric and gas demand;

(3) unfavorable or untimely rulings in rate or other cases filed or to be filed by the Utilities with the PUCN, including, but not limited to GRCs, the periodic applications to recover costs for fuel and purchased power that have been recorded by the Utilities in their deferred energy accounts, deferred natural gas costs recorded by SPPC for its gas distribution business, and revenue recovery programs relating to the EEIR;

(4) whether the Utilities will be able to integrate the new advanced metering system with their billing and other computer information systems and whether the technologies and equipment will perform as expected, and in all other respects, meet operational, commercial and regulatory requirements;

(5) wholesale market conditions, including availability of power on the spot market and the availability to enter into commodity financial hedges with creditworthy counterparties, including the impact as a result of the Dodd-Frank Act on counterparties who are lenders under our revolving credit facilities, which may 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) the ability and terms upon which NVE, 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: volatility in the global credit markets, changes in availability and cost of capital either due to market conditions or as a result of unfavorable rulings by the PUCN, a downgrade of the current debt ratings of NVE, NPC or SPPC, and/or interest rate fluctuations;

(7) unseasonable or severe weather, drought, threat of wildfire and other natural phenomena, which could affect the Utilities' customers' demand for power, could seriously impact the Utilities' ability and/or cost to procure adequate supplies of fuel or purchased power, could affect the amount of water available for electric generating plants in the Southwestern U.S., and could have other adverse effects on our business;

(8) 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), current suspension of the hedging program, physical availability, sharp increases in the prices for fuel (including increases in long-term transportation costs) and/or power, or a ratings downgrade;

(9) changes in and/or implementation of environmental laws or regulations, including the imposition of limits on emissions of carbon or other pollutants from electric generating facilities, which could significantly affect our existing operations as well as our construction program;

(10) construction risks, such as delays in permitting, changes in environmental laws, difficulty in securing adequate skilled labor, cost and availability of materials and equipment (including escalating costs for materials, labor and environmental compliance due to timing delays and other economic factors which may affect vendor access to capital), equipment failure, work accidents, fire or explosions, business interruptions, possible cost overruns, delay of in-service dates, and pollution and environmental damage;

(11) whether the Utilities can procure and/or obtain sufficient renewable energy sources in each compliance year to satisfy the Portfolio Standard in the State of Nevada;

(12) Changes in and/or implementation of FERC and NERC mandatory reliability, and other requirements for transmission system infrastructure, which could significantly affect existing and future operations.;

(13) employee workforce factors, including changes in and renewals of collective bargaining unit agreements, strikes or work stoppages, the ability to adjust the labor cost structure to changes in growth within our service territories;

(14) whether, following the Great Basin Water Network, et al. v. Nevada State Engineer litigation, certain permitted water rights of the SNWA that are used to supply water to the Utilities' power production plants and service territories could be re-opened, which could adversely impact the operations of those plants and future growth and customer usage patterns;

(15) explosions, fires, accidents and mechanical breakdowns that may occur while operating and maintaining an electric and natural gas system in the Utilities' service territory that can cause

unplanned outages, reduce generating output, damage the Utilities' assets or operations, subject the Utilities to third-party claims for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory fines or penalties on the Utilities;

(16) whether the Utilities will be able to continue to pay NVE dividends under the terms of their respective financing and credit agreements and limitations imposed by the Federal Power Act;

(17) whether NVE's BOD will continue to declare NVE's common stock dividends based on the BOD's periodic consideration of factors ordinarily affecting dividend policy, such as current and prospective financial condition, earnings and liquidity, prospective business conditions, regulatory factors, and restrictions in NVE's and the Utilities' agreements;

(18) further increases in the unfunded liability or changes in actuarial assumptions, the interest rate environment and the actual return on plan assets for our pension and other post retirement plans, which can affect future funding obligations, costs and pension and other post retirement plan liabilities;

(19) the effect that any future terrorist attacks, wars, threats of war or pandemics may have on the tourism and gaming industries in Nevada, particularly in Las Vegas, as well as on the national economy in general; including the impact of acts of terrorism or vandalism that damage or disrupt information technology and systems owned by the Utilities, or third parties on which the Utilities rely;

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

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

(22) changes in the business of the Utilities' major customers engaged in gold mining or gaming, including availability and cost of capital or power demands, 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 gaming establishments in California, other states and internationally; and

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

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. NVE, 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.

NOTE REGARDING RELIANCE ON STATEMENTS IN OUR CONTRACTS

In reviewing the agreements filed as exhibits to this Annual Report on Form 10-K, please remember that they are filed to provide you with information regarding their terms and are not intended to provide any other factual or disclosure information about NVE, the Utilities or the other parties to the agreements. The agreements contain representations and warranties by each of the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and:

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties to the agreement if those statements prove to be inaccurate;
- have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from what may be viewed as material to investors; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time.

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 NVE and its two primary subsidiaries, NPC and SPPC, collectively referred to as the ''Utilities'' (references to ''we,'' ''us'' and ''our'' refer to NVE and the Utilities collectively), and includes discussion of the following:

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

NVE'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 generation, transmission, distribution and sale of electricity and, in the case of SPPC, sale of natural gas. Other operations consist mainly of unregulated operations and the holding company operations. The Utilities are the principal operating subsidiaries of NVE and account for substantially all of NVE's assets and revenues. NVE, NPC and SPPC are separate filers for SEC reporting purposes and as such this discussion has been divided to reflect the individual filers (NVE, 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 electric service territory 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 generation, distribution and transmission operations. However, in January, 2011, SPPC sold its California Assets as discussed further in Note 16, *Assets Held for Sale,* in the Notes to Financial Statements; therefore, SPPC will no longer be subject to regulation by the CPUC. The FERC has jurisdiction under the Federal Power Act with respect to wholesale 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 ROR 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 impacts that seasonal weather, rate changes, and customer usage patterns have on demand for electric energy and resources. 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, while its gas business typically peaks in the winter. The variations in energy usage due to varying weather, customer growth and other energy usage patterns, including DSM programs and energy efficiency and conservation measures, necessitates a continual balancing of loads and resources and purchases and sales of energy under short and long term contracts. As a result, the prudent management and optimization of available resources has a direct effect on the operating and financial performance of the Utilities. Additionally, the timely recovery of purchased power and fuel costs, and other costs, and the ability to earn a fair return on investments are essential to the operating and financial performance of the Utilities.

Overview of Major Factors Affecting Results of Operations

NVE recognized net income of $226.9 million in 2010 compared to $182.9 million in 2009. The increase in net income is primarily due to an increase in gross margin, which is primarily due to NPC's increased rates as a result of NPC's 2008 GRC, effective July 1, 2009. See Note 2, *Segment Information,* of the Notes to Financial Statements. Also contributing to the increase in net income was lower operating expenses in 2010 compared to 2009 primarily due to a decrease in employee pension and benefit expenses and costs incurred in 2009 related to severance programs. See Note 17, *Severance Programs,* of the Notes to Financial Statements. Partially offsetting the increase in net income was higher income taxes as a result of a lower tax effective rate in 2009, an increase in interest expense on regulatory items primarily as a result of over-collected deferred energy balances and interest charges related to NVE's redemption of $230 million of its 8.625% Senior Notes due 2014, and $63.7 million of its 7.803% Senior Notes due 2012 and increased depreciation expense.

NVE recognized net income of $182.9 million in 2009 compared to $208.9 million in 2008. NPC's gross margin increased $114.7 million, primarily due to increased rates as a result of NPC's 2008 GRC, effective July 1, 2009. SPPC's electric gross margin increased $33.7 million while its gas gross margin remained relatively flat. SPPC's electric gross margin increased primarily due to SPPC's 2007 GRC, effective July 1, 2008. Consolidated net income decreased primarily due to an increase in other operating and maintenance expenses, depreciation and interest charges, some of which are costs related to the purchase of the Higgins Generating Station and the construction of the Clark Peaking Units, which were not included in rates prior to July 1, 2009 and a decrease in AFUDC, partially offset by higher revenues. Also contributing to the decrease in net income were severance costs as a result of NVE's reduction in workforce, discussed further in Note 17, *Severance Programs*, of the Notes to Financial Statements.

2010 Accomplishments

In 2010, NVE continued its execution of its three part strategy, discussed in detail later, to manage resources against our load by (1) encouraging energy efficiency and conservation programs, (2) the purchase and development of renewable energy projects, and (3) the construction of generating facilities, in an effort to reduce our reliance on purchased power, and expansion of transmission capabilities. Accomplishments under the three part strategy include:

Energy Efficiency and Conservation Programs:

- NPC's IRP, approved in July 2010, includes various DSM programs to increase energy efficiency and conservation programs totaling approximately $209.9 million over a three year period.
- SPPC's IRP, approved in October 2010, includes approximately $36 million in DSM programs.
- In March of 2010, NVE was awarded a $138 million grant in stimulus funding, made available through the American Recovery and Reinvestment Act, from the DOE specifically for NVE's $301 million NV Energize project. In August of 2010, the PUCN approved the project. In September, the grant was increased to $139 million and NVE committed to a $303 million total project budget in order to include the development of a Consumer Confidence Plan. The project will deploy the Smart Grid infrastructure necessary to: 1) enable the achievement of metering and customer service operating savings; 2) enable the expansion of demand response and energy efficiency benefits; and 3) provide customers better information to help manage their energy usage.

Purchase and Development of Renewable Energy Resources:

- NPC completed construction of the Goodsprings 7.5 MW (nominally rated) recovered energy project at its budgeted cost of $22 million.
- NPC received PUCN approval for seven long-term renewable energy PPAs totaling 443 MWs, in addition to two short term renewable PPAs.
- In April 2010, NPC and SPPC filed their joint Annual Compliance Report with the PUCN. SPPC reported that it met the Portfolio Standard for total PECs and the solar requirements of the Portfolio Standard. NPC reported that it met the solar requirement of the Portfolio Standard, but did not meet the Portfolio Standard requirement for total PECs. However, in October 2010, the PUCN approved a stipulation that allowed NPC to offset its 2009 PEC shortfall with credits earned in 2010 and a loan of surplus credits from SPPC.

Construction of Generating Facilities and Expansion of Transmission Capabilities:

- In 2010, construction of the 500 MW (nominally rated) natural gas generating station at the existing Harry Allen Generating Station continued with an expected completion by mid 2011.

- The PUCN granted the Utilities' request to move forward with the construction of ON Line with GBT, as discussed later in more detail. In August 2010, the Utilities and GBT finalized a TUA, which was closed in February 2011.

Other major accomplishments in 2010 included the adoption of regulations by the PUCN authorizing an electric utility to recover revenue attributable to reduced kWh sales related to our energy efficiency programs. See Note 3, *Regulatory Actions,* of the Notes to Financial Statements for further details. 2010 operating results benefitted from continued cost management, including the effects of the Severance Program which began in 2009 and lower pension costs. In addition, during 2010, the Utilities reduced their capital expenditures. During 2010, SPPC continued to receive the required regulatory approvals needed to consummate its sale of certain California assets to Cal Peco, which was completed on January 1, 2011. See Note 16, *Assets Held for Sale*, of the Notes to Financial Statements for further details.

Future Challenges

NVE and the Utilities must balance the needs of our customers and regulatory requirements while still continuing to provide value to our shareholders. Challenges arising from the need to balance these elements include but are not limited to:

- Economic conditions in Nevada and its effect on various interrelated factors including, but not limited to:
  - customer growth;
  - customer usage;
  - revenues;
  - pressure on regulators to limit necessary rate increases or otherwise lessen rate impacts upon customers;
  - load factors;
  - future capital projects and capital requirements;
  - managing operating and maintenance expenses within projected revenue growth without compromising safety, reliability and efficiency;
  - our liquidity and ability to access capital markets;
  - collections on accounts receivable; and
  - counterparty risk.
- Meeting the Portfolio Standard, which requires that the Utilities obtain 15% of their energy from renewable resources in 2011 and 2012, increasing to 25% by 2025; and,
- Future execution of the three part strategy, including the impact of economic conditions, rate impacts on customers and any future legislative or regulatory requirements.
- Full and timely recovery of regulatory costs.

Economic Conditions

In NPC's service territory, which consists primarily of Las Vegas, key economic indicators, as outlined below, continue to decline or have shown little improvement from 2009:

- Unemployment in Las Vegas was 14.9% in December 2010, up from 13% a year ago;
- In southern Nevada, construction activity, another leading indicator, has seen a decrease in the number of commercial permits while residential permits has remained relatively flat;
- Construction employment has decreased 22.8% as of November 2010 compared to November 2009;
- As of November 2010, taxable sales have increased 0.9% from a year ago;
- As of December 2010 gaming revenues have declined 2.6% from a year ago;
- As of December 2010 visitor volume increased 3.7% from a year ago;
- As of December 2010, the hotel/motel occupancy rate in Las Vegas has increased approximately 1.1% from a year ago; and
- The estimated room growth rate in 2010 was 1.2% primarily due to The Cosmopolitan Resort and Casino which added approximately 2,000 rooms. In 2011, room growth is expected to increase by 1.0% and then slow to 0.3% in 2012.

In SPPC's service territory, which consists primarily of Washoe County, key economic indicators, as outlined below, continue to decline or have shown little improvement from 2009:

- Unemployment in Washoe County was at 13.8% as of December 2010, up from 12.5 a year ago;
- Construction employment decreased 26.0% as of November 2010 from November 2009;
- As of November 2010, taxable sales increased 2.5% compared to a year ago; and
- As of December 2010, gaming revenues decreased 0.7% compared to a year ago.

Other economic conditions affecting Nevada include the national decrease in real estate market activity which makes it more difficult for individuals and businesses to sell their properties in order to relocate to Nevada. Gaming properties in southern Nevada are experiencing financial problems, including difficulties meeting debt payments, bankruptcies and delays or termination of construction projects which may further decrease the projected growth in rooms or offset any increases.

The Portfolio Standard

The Portfolio Standard as set forth by Nevada law requires a specific percentage of an electric service provider's total retail energy sales be obtained from renewable resources. Renewables include biomass, geothermal, solar, waterpower, wind and qualified recovered energy generation projects. In 2011 and 2012, the Utilities are required to obtain an amount of PECs equivalent to 15% of their total retail energy from renewables. Currently, the Portfolio Standard increases to 18% for 2013 and 2014 and reaches 20% in 2015 after which it increases to 22% for the years 2020 through 2024, and to 25% for 2025 and beyond. Moreover, not less than 5% of the total Portfolio Standard must be met from solar resources until 2016 when a minimum of 6% must be solar. The Portfolio Standard, discussed above, allows energy efficiency measures from qualified conservation programs to meet up to 25% of the

Portfolio Standard. Under this provision, a PEC is created for each kWh of energy conserved by qualified energy efficiency programs. In addition, energy saved during peak demand hours earns double the PECs for each kWh of energy conserved. After the DSM percentage allowance is fully utilized, NVE's strategy is to assess economic conditions and potential rate impacts in pursuing the implementation of cost effective DSM programs needed to achieve future Portfolio Standard requirements. The successful execution of the three part strategy, as discussed below, will be critical to our ability to meet the Portfolio Standard.

Three Part Strategy

The continued execution of the three part strategy which began in 2007 to manage resources against our load by (1) encouraging energy efficiency and conservation programs, (2) the purchase and development of renewable energy projects, and (3) construction of generating facilities in an effort to reduce our reliance on purchased power and expansion of transmission capability will be critical to NVE's ability to meet its state mandated Portfolio Standard.

Energy Efficiency and Conservation Programs

As stated above, the Portfolio Standard allows energy efficiency measures from qualified conservation programs to meet up to 25% of the Portfolio Standard. As such, NVE remains committed to investing in such programs that qualify toward the Portfolio Standard, reduce our peak load, especially during peak periods, and are cost-effective. NVE's current 2011 budget includes approximately $89 million for energy efficiency and conservation programs. Furthermore, the Utilities will continue with the implementation of NV Energize which will provide NVE with the Smart Grid infrastructure necessary to enable: 1) enable the achievement of metering and customer service operating savings; 2) enable the expansion of demand response and energy efficiency benefits; and 3) provide customers better information to help manage their energy usage.

Purchase and Development of Renewable Energy Resources

NVE faces a significant challenge as it strives to balance the need to meet the Portfolio Standard, with the changes in load forecast and the uncertainty of renewable energy project development, either for financial or resource related reasons, with renewable energy providers. However, NVE remains committed to renewable energy and continues to seek cost effective opportunities that will benefit our state, customers and environment. Depending on its needs, during 2011 NPC may issue requests for proposals for renewable energy contracts, explore opportunities to either jointly construct or pursue the development of projects using wind, geothermal and solar, or undertake additional short-term purchases.

Construction of Generating and Transmission Facilities and Optimizing the Operation of Current Generation Assets

NPC is scheduled to complete construction of the 500 MW (nominally rated) natural gas generating station at the existing Harry Allen Generating Station, and it is expected to be operational by mid 2011.

In February 2011, NVE and the Utilities consummated their agreement with GBT to jointly construct and own ON Line, a 500 Kv transmission line. The completion of ON Line, expected in late 2012, will connect NVE's southern and northern service territories and will provide the ability to jointly dispatch energy throughout the state and provide access to isolated renewable energy resources in parts of northern and eastern Nevada, which will enhance NVE's ability to meet its Portfolio Standard, discussed above, and lower costs to our customers.

ON Line is a Joint Project between the Utilities and GBT, an affiliate of LS Power. The Joint Project consists of two phases. In Phase 1 of the Joint Project, the parties would complete construction of an initial 500 kV interconnection between the Robinson Summit substation on the SPPC system and the Harry Allen Generating Station on the NPC system by late 2012. Under the Joint Project, the Utilities will own a 25% interest in Phase 1 and enter into a transmission use agreement with GBT for its 75% interest in Phase 1. The Utilities 25% interest in Phase 1of the Joint Project, which approximates $127 million, will be allocated 95% and5% to NPC and SPPC, respectively. The Utilities will have rights to 100% of the capacity of Phase 1, which is estimated at approximately 600 MW. If GBT elects to construct Phase 2, it would construct two additional transmission segments at either end of ON Line: one extending from Robinson Summit north to Midpoint, Idaho, and the other commencing at the Harry Allen Generating Station and interconnecting south to the Eldorado substation. GBT would pay for and own 100% of Phase 2 facilities. However, NPC and SPPC would have rights to additional transmission capacity from Midpoint to Eldorado (for a total of approximately 760 MW based on a rating of 2,000 MW for the complete path).

In 2011, NVE will have more generating capacity than its forecasted load requirement. However, the additional resources, may be affected by, but not limited to, the unplanned retirement of aging or less efficient generating stations, the timing or achievement of commercial operation in regards to renewable energy power purchases not yet commercially operable, as well as the intermittent reliability of renewable energy resources, customer behavior with respect to DSM programs and environmental regulation, which may limit our ability to operate certain generating units. As such, the additional resources provide the Utilities the ability to maintain a reliable level of energy. NVE's management continuously optimizes the Utilities' energy portfolios in order to meet load obligations in a cost effective and reliable manner.

Full and Timely Recovery of Regulatory Costs

The Utilities are required to file rate cases every three 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, the Utilities are required to file a triennial IRP which is a comprehensive plan that considers customer energy requirements and proposes the resources to meet that requirement. Resource additions approved by the PUCN in the resource planning process are deemed prudent for ratemaking purposes. Between IRP filings, the Utilities may seek PUCN approval for modifications to their resource plans and for power purchases. The Utilities remain focused on communicating with regulators the necessity of investments to better serve our customers, the prudency of the costs incurred, and the importance of a reasonable return on investment for our shareholders. Management cannot predict the future decisions on our rate cases, but believe the regulatory process, described above, coupled with prudent management provides a reasonable basis for the recovery of our investments.

2011 Goals

Management cannot predict when economic recovery may occur in Nevada, but expects that the Nevada economy will continue to struggle for the next several years. As such, our primary goals will focus on meeting the challenges discussed above, by:

- Continuing to monitor economic conditions in Nevada and adjusting our business decisions accordingly;
- Meeting the Portfolio Standard in 2011 and building a sustainable foundation for future requirements by:
  - Continuing to meet system deployment milestones in order to achieve NV Energize project completion by 2012;
  - Continued investment in energy efficiency and conservation programs;
  - The purchase and development of cost effective renewable energy projects;
  - Construction of ON Line;
  - Completion of expansion at the Harry Allen Generating Station;
  - Optimizing generating assets; and
- Full and timely recovery of regulatory costs, in particular, NPC's GRC to be filed in June 2011.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

NVE prepared its consolidated financial statements in accordance with GAAP. 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 NVE 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 NVE's BOD. 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 NVE and the Utilities.

Regulatory Accounting

The Utilities' retail rates are currently subject to the approval of the PUCN and are designed to recover the cost of providing generation, transmission and distribution services. NVE is a ''holding company'' under the Public Utility Holding Company Act of 2005 (PUHCA 2005). As a result, NVE and all of its subsidiaries (whether or not engaged in any energy related business) are required to maintain books, accounts and other records in accordance with FERC regulations and to make them available to the FERC and the PUCN. In addition, the PUCN or the FERC have the authority to review allocations of costs of non-power goods and administrative services among NVE and its subsidiaries. The FERC has the authority generally 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 NVE, NPC and/or SPPC and/or any other affiliated company.

As a result, the Utilities qualify for the application of regulatory accounting treatment as allowed by the Regulated Operations Topic of the FASC. The accounting guidance for regulated operations 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. The accounting guidance prescribes the method to be used to record the financial transactions of a regulated entity. The criteria for applying the accounting guidance for regulated operations 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. 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 either because we have received prior PUCN approval or due to regulatory precedent set for similar circumstances. 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. 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.'' 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/expense on regulatory items in the current period.

The Utilities are exposed to commodity price risk primarily related to changes in the market price of electricity, and the suspension of our hedging program, 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 and decreases 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.

Accounting for Derivatives and Hedging Activities

NVE, NPC and SPPC apply the accounting guidance as required by the Derivatives and Hedging Topic of the FASC. The accounting guidance for derivative instruments requires that an entity recognize all derivatives as either assets or liabilities in the balance sheet and measure those instruments at fair value, unless they meet the normal purchase/normal sale scope exception. 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 may 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, the Utilities' use over-the-counter options with financial institutions and other energy companies to manage price risk which are typically considered derivatives under the Derivatives and Hedging Topic of the FASC and are marked-to-market in the statement of financial position unless the contract qualifies for the normal purchases or sales scope exception per the accounting guidance for derivative instruments.

The PUCN has authorized the Utilities to defer the recognition of mark-to-market gains and losses on energy commodity transactions that would otherwise be recorded to the income statement and/or comprehensive income, until the period of settlement by recording a risk management regulatory asset or liability. Upon settlement of these transactions, actual gains and losses are recognized as fuel and purchased power costs.

Interest Rate Swap Contracts

NVE, NPC, and SPPC are subject to risk of fluctuating interest rates in the normal course of business. As such, management may enter into interest rate swaps to manage fixed interest rate exposure with variable interest rate instruments in order to lower overall borrowing costs. If the conditions required by the Regulated Operations Topic of the FASC are met, the Utilities are permitted to defer the change in fair value of the interest rate swap as risk management regulatory asset/liability.

Fair Value Measurements and Disclosures

NVE and the Utilities' follow the Fair Value Measurements and Disclosure Topic of the FASC, which defines fair value, establishes a framework for measuring fair value and enhances disclosures about assets and liabilities recorded at fair value.

Fair Value Measurements and Disclosure Topic of the FASC establishes a three-level hierarchy which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The three levels are defined as follows:

Level 1 - Quoted prices in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities.

Level 2 - Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant.

As required by the Fair Value Measurements and Disclosure Topic of the FASC, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. NVE and the Utilities' assessment of the significance of a particular input to fair value measurements requires judgment. The fair value of the Utilities' assets and liabilities are sensitive to market price fluctuations that can occur on a daily basis. The use of different assumptions and variables in determining fair value could significantly impact the valuation and classification within the fair value hierarchy of assets and liabilities. See Note 1, *Summary of Significant Accounting Policies*, Note 4, *Investments and Other Property*, Note 9, *Derivatives and Hedging Activities* and Note 11, *Retirement Plan and Post-Retirement Benefits* in the Notes to Financial Statements for more detailed disclosure of NVE's, NPC's and SPPC's fair value measurements.

Accounting for Income Taxes

Current and deferred income tax provisions and benefits as well as deferred income tax assets and liabilities involve significant management estimates and judgments. NVE and the Utilities file a consolidated federal income tax return. Current income taxes are allocated based on NVE and the Utilities' respective taxable income or loss and tax credits as if each utility filed a separate return.

NVE and the Utilities recognize deferred tax liabilities and assets for the future tax consequences of events that have been included in the financial statements or tax returns. Deferred tax liabilities and assets are determined based on the difference between the financial statement and tax basis of assets and liabilities using tax rates in effect for the year in which the differences are expected to reverse. Deferred tax assets are also recorded for deductions incurred and credits earned that have not been utilized in tax returns filed or to be filed for tax years through the date of the financial statements. Management considers estimates of the amount and character of future taxable income by tax jurisdiction in assessing the likelihood of realization of deferred tax assets. If it is not more likely than not that a deferred tax asset will be realized in its entirety, a valuation allowance is recorded with respect to the portion estimated not likely to be realized. Management has determined that the Federal NOL does not require a valuation allowance based on projections of future taxable income and the reversal of deferred tax liabilities.

At December 31, 2010, NVE had a gross federal NOL carryover of $458.0 million. The following table summarizes the NOL and tax credit carryovers and associated carryover periods, and valuation allowance for amounts which NVE has determined that realization is unlikely as of December 31, 2010 (dollars in thousands):

	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
Federal NOL	$160,291	$ -	$160,291	2023-2030
Research and development credit	11,864	-	11,864	2023-2030
Arizona state coal credits	1,608	1,455	153	2011-2015
Total	$173,763	$1,455	$172,308	

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, our financial condition and results of operations in future periods, and the review of filed tax returns by taxing authorities. NVE and the Utilities' income tax returns are regularly audited by applicable tax authorities. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more-likely-than-not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50% likely of being realized upon settlement. NVE and the Utilities classify interest and penalties associated with unrecognized tax benefits as interest and other expense, respectively, within the income statement. No interest expense or penalties associated with unrecognized tax benefits have been recorded. As of December 31, 2010, NVE and the Utilities recorded a liability for uncertain tax positions of approximately $35.7 million.

The Utilities reduce rates to reflect the current tax benefits associated with recognizing certain tax deductions sooner than when the expenses are recognized for financial reporting purposes. A regulatory asset is recorded for these amounts to reflect the future increases in income taxes payable that will be recovered from customers when these temporary differences reverse. The Utilities have been fully normalized since 1987. AFUDC-equity is recorded on an after-tax basis. Accordingly, a regulatory asset is recorded when AFUDC-equity is recognized. This regulatory asset reverses as the related plant is depreciated, resulting in an increase to the tax provision. The Utilities also record regulatory liabilities for obligations to reduce rates charged customers for deferred taxes recovered from customers in prior years at corporate tax rates higher than the current tax rates. The reduction in rates charged customers will occur as the temporary differences resulting in the excess deferred tax liabilities reverse. NVE and subsidiaries had a net regulatory tax liability of $237.6 million at December 31, 2010.

Environmental Contingencies

NVE 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 EPA, NDEP and Clark County Department of Air Quality and Environmental Management administer regulations involving air and water quality, solid, and hazardous and toxic waste.

NVE 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, NVE or its subsidiaries may be a responsible party for environmental cleanup at any site identified by a regulatory body. The management of NVE 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 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.

Depending on whether environmental liabilities occurred from normal operations or as part of new environmental laws, the Utilities accrue for environmental remediation liabilities in accordance with the accounting guidance required by the Asset Retirement and Environmental Obligations Topic of the FASC. Estimated costs from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study or when the accounting requirements for environmental obligations have been met. Such costs are adjusted as additional information develops or circumstances change. Certain environmental costs receive regulatory accounting treatment, under which the costs are recorded as regulatory assets. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

Note 1, *Summary of Significant Accounting Policies*, Asset Retirement Obligations, of the Notes to Financial Statements and Note 13, *Commitments and Contingencies,* of the Notes to Financial Statements, discusses the environmental matters of NVE 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 NVE 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 NVE and its subsidiaries.

Defined Benefit Plans and Other Post-retirement Plans

As further explained in Note 11, *Retirement Plan and Post-Retirement Benefits* of the Notes to Financial Statements, NVE maintains a qualified pension plan, a non-qualified supplemental executive retirement plan (SERP) and restoration plan, as well as a post-retirement benefit (OPEB) plan which provides health and life insurance for retired employees.

Pension Plans

NVE's reported costs of providing non-contributory defined pension benefits (described in Note 11, *Retirement Plan and Post-Retirement Benefits* of the Notes to Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions for future experience.

In accordance with the Compensation Retirement Benefits Topic of the FASC, 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. Furthermore, the Compensation Retirement Benefits Topic of the FASC 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 NVE recovers costs through rates, amounts recovered in rates will be recorded as Other Regulatory Assets under the provisions of the Regulated Operations Topic of the FASC, and will be recognized as expense over a period of time.

For the years ended December 31, 2010, 2009, and 2008, NVE recorded pension expense for all pension plans of approximately $30.8 million, $51.6 million, and $24 million, respectively, in accordance with the accounting guidance as defined by the Compensation Retirement Benefits Topic of the FASC. Actual payments of benefits made to retirees and terminated vested employees for the years ended December 31, 2010, 2009 and 2008 were $58.0 million, $40.1 million, and $27.4 million, respectively. Pension costs are impacted by actual employee demographics (including age and employment periods), the level of contributions NVE 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 June 2010, the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010 was signed into law. This legislation permits employers to choose between alternative amortization methods for shortfalls due to losses in asset market values. The legislation is designed to reduce contributions to defined benefit pension plans by allowing them to be spread them over a longer period of time. NVE is currently evaluating the options and impact of this legislation, but does not believe it would need to avail itself of the benefits under this Act. NVE has not taken into account any possible impacts of this legislation in determining estimated future contributions.

Plan Assets

NVE'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. See Note 11, *Retirement and Post-Retirement Benefits,* of the Notes to Financial Statements, for further discussion on NVE's investment strategy and asset allocation.

Plan Assumptions and Sensitivities Analysis

As further described in Note 11, *Retirement Plan and Post-Retirement Benefits*, of the Notes to Financial Statements, NVE reduced the discount rate used in determining pension expense from 5.80% in 2010 to 5.10% for the calendar year 2011.

In selecting an assumed discount rate for fiscal years 2010 and 2009 disclosures, and for fiscal years 2010, 2009 and 2008 pension cost, NVE's projected benefit payments were matched to the yield curve derived from a portfolio of over 300 high quality Aa bonds with yields within the 10^{th} to 90^{th} percentiles of these bond yields.

In selecting an assumed rate of return on plan assets, NVE considers past performance and economic forecasts for the types of investments held by the plan. NVE used an assumed rate of return on plan assets of 6.75% and 7.10% for 2010 and 2009, respectively, as disclosed in Note 11, *Retirement and Post-Retirement Benefits,* of the Notes to Financial Statements. Investment returns on plan assets in the retirement plan increased by approximately $70.8 million in 2010 and increased by approximately $123.7 million in 2009. Due to the increases in investment returns and the contributions by NVE, the funded status of the plan has improved compared to the prior year.

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, NVE 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	Impact on PBO	Impact on PC
Discount Rate Increase/(Decrease)	1%	$(82.88)	$(7.30)
Rate of Return on Plan Assets Increase/(Decrease)	1%	$ 0.00	$(6.56)

Other Post-retirement Benefits

NVE's reported costs of providing other post-retirement benefits (described in Note 11, *Retirement Plan and Post-Retirement Benefits*, of the Notes to Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

For the year ended December 31, 2010, 2009, and 2008, NVE recorded other post-retirement benefit expense of $5.4 million, $10.6 million and $7.7 million, respectively, in accordance with the provisions of the Compensation Retirement Benefits Topic of the FASC. Actual payments of benefits made to retirees for the year ended December 31, 2010, 2009 and 2008 were $12.5 million, $11.0 million and $11.8 million, respectively. Other post-retirement 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 post-retirement benefit costs. Other post-retirement 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 post-retirement benefit obligation and post-retirement costs.

In March 2010, the President signed into law comprehensive health care reform legislation under the Patient Protection and Affordable Care Act of 2010. One feature of this legislation is the elimination of the tax deductibility of employer health care costs for retiree prescription drug expenses that are reimbursed as part of the Medicare Part D federal subsidy. NVE has not participated in the subsidy program since 2008, and therefore does not expect any significant impact on its financial statements as a result of this legislation.

Plan Assets

NVE's other post-retirement 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 post-retirement benefit costs in future periods. See Note 11, *Retirement and Post-Retirement Benefits,* of the Notes to Financial Statements, for further discussion on NVE's investment strategy and asset allocation.

Plan Assumptions and Sensitivities Analysis

As further described in Note 11, *Retirement Plan and Post-Retirement Benefits,* of the Notes to Financial Statements, NVE has revised the discount rate for its 2010 disclosures to 5.2%, as compared to

2009 disclosures of 5.75%. For determining the expense to be recorded in 2011, NVE moved to a 5.2% discount rate from 5.75% in 2010. In determining the other post-retirement benefit obligation and related cost, these assumptions can change with each measurement date, and such changes could result in material changes to such amounts.

In selecting an assumed discount rate for fiscal year 2010 other post-retirement benefits cost and disclosures, NVE's projected benefit payments were matched to the yield curve derived from a portfolio of over 300 high quality Aa bonds with yields within the 10th to 90th percentiles of these bond yields.

In selecting an assumed rate of return on plan assets, NVE considers past performance and economic forecasts for the types of investments held by the plan. NVE used an assumed rate of return on plan assets of 7.10% for some plans and 6.75% for others in 2010 and 7.10% for all plans in 2009, as disclosed in Note 11, *Retirement and Post-Retirement Benefits,* of the Notes to Financial Statements. Investment returns on plan assets increased $10.6 million in 2010 and increased $17.6 million in 2009.

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, NVE and its actuaries expect that a decrease would impact the projected accumulated other post-retirement benefit obligation (APBO) and the reported annual other post-retirement 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	Impact on APBO	Impact on PBC
Discount Rate Increase/(Decrease)	1%	$(17.31)	$(1.28)
Health Care Cost Trend Rate Increase/(Decrease)	1%	$ 8.00	$ 1.32
Rate of Return on Plan Assets Increase/(Decrease)	1%	$ 0.00	$(0.89)

Revenues

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, line loss and the Utilities' current tariffs. Accounts receivable as of December 31, 2010, include unbilled receivables of $89 million and $60 million for NPC and SPPC, respectively. Accounts receivable as of December 31, 2009, include unbilled receivables of $103 million and $78 million for NPC and SPPC, respectively.

Alternative Revenues

As adopted by the PUCN in July 2010, the Utilities are authorized to recover lost revenue that is attributable to the measurable and verifiable effects associated with the implementation of efficiency and conservation programs approved by the PUCN. The Utilities account for the effects of such regulation in accordance with FASC 980-605-25, Alternative Revenue Programs which permits the recording of revenue if all of the following conditions are met 1) the program allows for automatic adjustment of future rates, 2) the amount of revenues is objectively determinable and probable of recovery and 3) the additional revenues will be collected within 24 months. See Note 3, *Regulatory Actions*, EEIR, of the Notes to Financial Statements for further discussion on the recording of such revenues.

The measurable and verifiable effects associated with the implementation of efficiency and conservation programs are complex calculations that require the Utilities to estimate the amount of kWh savings. The amount of kWh savings is based on numerous assumptions and statistical data, which are verified by an independent third party, but still requires verification by the PUCN. The Utilities' revenues may be impacted to the extent that kWh savings approved by the PUCN differ from the amounts estimated.

RECENT PRONOUNCEMENTS

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

NV ENERGY, INC.

RESULTS OF OPERATIONS

NV Energy, Inc. (Holding Company) and Other Subsidiaries

NVE (Holding Company)

The Holding Company's (stand alone) operating results included approximately $50.1 million, $38.7 million and $41.3 million of interest costs for the years ended December 31, 2010, 2009 and 2008, respectively. The increase in interest costs for the year ended December 31, 2010 as compared to the same period in 2009 was primarily due to the early redemption of $230 million in the aggregate principal amount of 8.625% Senior Notes due 2014, and approximately $63.7 million in the aggregate principal amount of 7.803% Senior Notes due 2012 and the issuance of $315 million 6.25% Senior Notes, due 2020. The decrease in interest costs for the year ended December 31, 2009 as compared to the same period in 2008 was primarily due to debt redemptions in 2008. See Note 6, *Long-Term Debt* of the Notes to Financial Statements, for further discussion of debt transactions.

Other Subsidiaries

Other Subsidiaries of NVE, except for NPC and SPPC, did not contribute materially to the consolidated results of operations of NVE.

NV Energy, Inc. (Consolidated)

See *Executive Overview*, Overview of Major Factors Affecting Results of Operations for NVE Consolidated.

ANALYSIS OF CASH FLOWS

NVE's cash flows increased during 2010 compared to 2009 due to an increase in cash from operating activities and a decrease in cash used by investing activities, offset by a decrease in cash from financing activities.

Cash From Operating Activities. The increase in cash from operating activities is primarily due to increased revenues as a result of the rate increase in NPC's GRC and decreased fuel and purchased power costs, offset by BTER, WECA and DEAA rate reductions, a decrease in funding for pension plans, an increase in spending on energy conservation programs, and a refund to a transmission customer in 2009.

Cash Used By Investing Activities. Cash used by investing activities decreased mainly due to the slowdown in construction for infrastructure, and proceeds from the sale of property.

Cash From Financing Activities. Cash from financing activities decreased primarily due to the redemption of SPPC's 6.25% General and Refunding Mortgage Notes, Series H due 2012 in an aggregate principal amount of $100 million, a decrease in debt issuance at NPC, an increase in payments on NPC's revolving credit facility, and higher dividend payments.

LIQUIDITY AND CAPITAL RESOURCES (NVE CONSOLIDATED)

Overall Liquidity

NVE'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, in the case of SPPC, natural gas. Significant uses of cash flows from operations include the purchase of electricity and natural gas, other operating expenses, capital expenditures and interest. Operating cash flows can be significantly influenced by factors such as weather, regulatory outcomes, and economic conditions. Available liquidity as of December 31, 2010 was as follows (in millions):

	Available Liquidity as of December 31, 2010 (in millions)		
	NVE	**NPC**	**SPPC**
Cash and Cash Equivalents	$13.6	$ 60.1	$ 9.6
Balance available on Revolving Credit Facilities[1]	N/A	585.3	219.3
Less reduction for hedging transactions[2]	N/A	(28.3)	(13.8)
	$13.6	$617.1	$215.1

(1) As of February 23, 2011, NPC and SPPC had approximately $569.6 million and $230.9 million available under their revolving credit facilities, which includes reductions in availability for hedging transactions and letters of credits, as discussed further under NPC's and SPPC's *Financing Transactions*.

(2) Reduction for hedging transactions reflects balances as of November 30, 2010.

NVE and the Utilities attempt to maintain their cash and cash equivalents in highly liquid investments, such as U.S. Treasury Bills and bank deposits. In addition to cash on hand, the Utilities' may use their revolving credit facilities in order to meet their liquidity needs. Alternatively, depending on the usage of their revolving credit facilities, the Utilities may issue debt, subject to certain restrictions as discussed in *Factors Affecting Liquidity*, *Ability to Issue Debt*, below.

NVE and SPPC have no significant debt maturities in either 2011 or 2012. However, NPC's debt maturities in 2011 and 2012 include its $350 million 8.25% General and Refunding Notes, Series A, which mature on June 1, 2011 and its $130 million 6.50% General and Refunding Notes, Series I, which mature on April 15, 2012. In addition, NPC is required to redeem approximately $98.1 million of its variable rate debt, due 2020, prior to ON Line's commercial operation date, expected in late 2012.

NVE and the Utilities anticipate that they will be able to meet short-term operating costs, such as fuel and purchased power costs, with internally generated funds, including the recovery of deferred energy, and the use of their revolving credit facilities. Furthermore, in order to fund long-term capital requirements and maturing debt obligations, NVE and the Utilities will use a combination of internally generated funds, the Utilities' revolving credit facilities, the issuance of long-term debt and/or equity and, in the case of the Utilities, capital contributions from NVE. However, if energy costs rise at a rapid rate and the Utilities do not recover the cost of fuel, purchased power and operating costs in a timely manner or the Utilities were to experience a credit rating downgrade resulting in the posting of collateral as discussed below under Gas Supplier Matters and Financial Gas Hedges, the amount of liquidity available to the Utilities could be significantly less. In order to maintain sufficient liquidity, NVE and the Utilities may be required to delay capital expenditures, re-finance debt or issue equity at NVE.

The ability to issue debt, as discussed later, is subject to certain covenant calculations which include net income of NVE and the Utilities. As a result of these covenant calculations and the seasonality of the Utilities' business, the ability to issue debt can vary from quarter to quarter and the Utilities utilization of their revolving credit facilities may be limited.

In 2010, the Utilities credit ratings on their senior secured debt remained at investment grade (see *Credit Ratings* below). In 2010, NVE and the Utilities did not experience any limitations in the credit markets nor do we expect any in 2011. However, disruptions in the banking and capital markets not specifically related to NVE or the Utilities may affect their ability to access funding sources or cause an increase in the interest rates paid on newly issued debt.

As of February 23, 2011, NVE has approximately $26.2 million payable of debt service obligations remaining for 2011, which it intends to pay through dividends from subsidiaries. (See *Factors Affecting Liquidity-Dividends from Subsidiaries* below). On February 3, 2011, SPPC declared a dividend payable to NVE of $38 million.

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

Detailed below are NVE's Capital Structure, Capital Requirements, recently completed 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

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

	2010		2009	
	Amount	Percent of Total Capitalization	Amount	Percent of Total Capitalization
Current Maturities of Long-Term Debt	$ 355,929	4.1%	$ 134,474	1.6%
Long-Term Debt	4,924,109	57.1%	5,303,357	61.2%
Shareholders' Equity	3,350,818	38.8%	3,223,922	37.2%
Total	$8,630,856	100%	$8,661,753	100%

Capital Requirements

Construction Expenditures

NVE's consolidated cash requirements for construction expenditures for 2011 are projected to be $501.6 million. NVE's consolidated cash requirements for construction expenditures for 2011-2015 are projected to be $2.3 billion. Cash used by investing activities for the years ended 2010, 2009, and 2008 were approximately $568.1 million, $800.6 million, and $1.5 billion, respectively. To fund future capital projects, NVE 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, the issuance of equity by NVE.

Estimated construction expenditures for PUCN approved projects, projects under contract, compliance projects and other base capital requirements are as follows (dollars in thousands):

	2011	2012-2015	Total 5 - Year
Electric Facilities:			
Generation	$177,572	$ 749,281	$ 926,853
Distribution	183,078	612,640	795,718
Transmission	82,316	285,871	368,187
Other	93,801	251,454	345,255
Total	536,767	1,899,246	2,436,013
Gas Facilities:			
Distribution	16,119	66,164	82,283
Other	297	1,238	1,535
Total	16,416	67,402	83,818
Common Facilities	18,307	50,094	68,401
Total	$571,490	$2,016,742	$2,588,232

Total estimated cash requirements related to construction projects consist of the following (dollars in thousands):

	2011	2012-2015	Total 5 - Year
Construction Expenditures	$571,490	$2,016,742	$2,588,232
AFUDC	(22,756)	(96,330)	(119,086)
Net Salvage/ Cost of Removal	(5,277)	(34,625)	(39,902)
Net Customer Advances and CIAC	(41,810)	(136,413)	(178,223)
Total Cash Requirements	$501,647	$1,749,374	$2,251,021

Contractual Obligations (NVE Consolidated)

The table below provides NVE's contractual obligations on a consolidated basis, as of December 31, 2010, (except as otherwise indicated) that NVE expects to satisfy through a combination of internally generated cash and, as necessary, through the issuance of short-term and long-term debt. Certain contracts contain variable factors which required NVE to estimate the obligation depending on the final variable amount. Actual amounts could differ. The table does not include estimated construction expenditures described above, except for major capital projects for which the Utilities have executed contracts by December 31, 2010, or funding requirements under pension and other post-retirement benefit plans, as discussed in Note 11, *Retirement Plan and Post-Retirement Benefits* of the Notes to Financial Statements, as of December 31, 2010. Additionally, at December 31, 2010, NVE has recorded an uncertain tax liability of $35.7 million in accordance with the accounting guidance for Uncertainty in Income Taxes Topic of the FASC all of which is classified as non-current. NVE is unable to make a reasonably reliable estimate of the period of cash payments to relevant tax authorities; consequently, none of the uncertain tax liability is included in the contractual obligations table below (dollars in thousands):

	Payment Due by Period						
	2011	2012	2013	2014	2015	Thereafter	Total
NPC/SPPC Long-Term Debt Maturities	$ 350,000	$ 130,000	$ 265,000	$ 125,000	$ 250,000	$ 3,595,192	$ 4,715,192
NPC/SPPC Long-Term Debt Interest Payments	268,300	250,251	243,245	225,327	210,868	2,003,671	3,201,662
NVE Long-Term Debt Maturities	-	-	-	-	-	506,500	506,500
NVE Long-Term Debt Interest Payments	32,614	32,614	32,614	32,614	32,614	116,982	280,052
Purchased Power(1)	425,819	428,515	438,834	420,044	433,230	3,241,516	5,387,958
Purchase Power - Not Commercially Operable(2)	12,651	76,741	84,812	159,407	218,680	4,830,319	5,382,610
Coal and Natural Gas	520,039	207,830	55,479	52,590	50,763	147,253	1,033,954
Transportation(3)	146,963	159,949	184,369	172,405	155,425	1,915,410	2,734,521
Long-Term Service Agreements(4)	24,780	19,950	18,763	19,277	19,722	87,141	189,633
Capital Projects(5)	236,099	134,887	43,139	-	-	-	414,125
Operating Leases	22,140	18,519	16,853	14,873	11,257	120,912	204,554
Capital Leases	9,976	9,828	9,845	7,435	4,831	66,030	107,945
Total Contractual Cash Obligations	$2,049,381	$1,469,084	$1,392,953	$1,228,972	$1,387,390	$16,630,926	$24,158,706

(1) Related party purchase power agreements have been eliminated for the years 2011 and 2012. Upon completion of ON Line, expected in late 2012, the related party purchase power agreements will no longer be required.

(2) Represents estimated payments under renewable energy power purchase contracts, which have been approved by the PUCN and are contingent upon the developers obtaining commercial operation and their ability to deliver energy.

(3) Included is the TUA with GBT of which NPC is responsible for 95% and SPPC 5% and is contingent upon final construction costs and reaching commercial operation, which is expected in late 2012.

(4) Amounts based on estimated usage.

(5) Capital projects include construction costs at the Harry Allen Generating Station and NV Energize and NPC's requirement to purchase the undepreciated cost of capital of Reid Gardner #4 from CDWR. Additionally, the Utilities, as joint owners, have obligations regarding the construction of ON Line, of which NPC will be responsible for 95% and SPPC 5%.

Pension and Other Postretirement Benefit Plan Matters

NVE has a qualified pension plan and other postretirement benefits plan which cover substantially all employees of NVE, NPC and SPPC. The annual net benefit cost for the plans is expected to decrease in 2011 by approximately $7.3 million compared to the 2010 cost of $36.2 million. As of December 31, 2010, the measurement date, the plan was under funded under the provisions of the Compensation Retirement Benefits Topic of the FASC. Refer to Note 11, *Retirement Plan and Post-Retirement Benefits*, of the Notes to Financial Statements. During 2010, NVE funded a total of $40 million to the trusts established for these plans. At the present time it is not expected that additional funding will be required in 2011 to meet the minimum funding level requirements defined by the Pension Protection Act of 2006. However, NVE and the Utilities have included in their 2011 assumptions funding levels similar to the 2010 funding. The amounts to be contributed in 2011 may change subject to market conditions.

Financing Transactions (NVE-Holding Company)

Senior Notes

In November 2010, NVE issued and sold $315 million of its 6.25% Senior Notes, due 2020. Of the approximately $311 million in net proceeds, $307 million was used in December 2010 to redeem the approximately $230 million in the aggregate principal amount of 8.625% Senior Notes due 2014, and the approximately $63.7 million in the aggregate principal amount of 7.803% Senior Notes due 2012. The 8.625% Notes were redeemed at a purchase price of $1,028.75 for each $1,000 principal amount of the Notes, plus accrued interest. The 7.803% Notes were redeemed at a purchase price of $1,019.51 for each $1,000 principal amount of the Notes, plus accrued interest. The remaining net proceeds were used for general corporate purposes.

Factors Affecting Liquidity

Ability to Issue Debt

Certain debt of NVE (holding company) places restrictions on debt incurrence, liens and dividends, unless, at the time the debt is incurred, the ratio of cash flow to fixed charges for NVE's (consolidated) 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, 2010, NVE (consolidated) would be allowed to incur up to $1.9 billion of additional indebtedness, assuming an interest rate of 7%. The amount of additional indebtedness allowed would likely be impacted if there is a change in current market conditions or material change in our financial condition.

Notwithstanding this restriction, under the terms of the debt, NPC and SPPC would still be permitted to incur a combined total of up to $750 million in indebtedness and letters of credit under their respective revolving credit facilities. As of December 31, 2010, the combined total outstanding indebtedness and letters of credit under their respective revolving credit facilities was approximately $45.4 million. See NPC's and SPPC's *Ability to Issue Debt* sections for further discussion of the Utilities' limitations on ability to issue debt.

If the applicable series of NVE 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 NVE Notes remain investment grade by both Moody's and S&P (see *Credit Ratings* above).

Effect of Holding Company Structure

As of December 31, 2010, NVE (on a stand-alone basis) has outstanding debt and other obligations including, but not limited to: $191.5 million of its unsecured 6.75% Senior Notes due 2017; and $315 million of its unsecured 6.25% Senior Notes due 2020.

Due to the holding company structure, NVE's right as a common shareholder to receive assets of any of its direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiary by its creditors. Therefore, NVE'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, 2010, NVE, NPC, SPPC and their subsidiaries had approximately $5.3 billion of debt and other obligations outstanding, consisting of approximately $3.6 billion of debt at NPC, approximately $1.2 billion of debt at SPPC and approximately $507 million of debt at the holding company and other subsidiaries. Although NVE and the Utilities are parties to agreements that limit the amount of additional indebtedness they may incur, NVE and the Utilities retain the ability to incur substantial additional indebtedness and other liabilities.

Certain NVE debt agreements contain covenants that limit the amount of restricted payments, including dividends that may be made by NVE. However, permitted payments, under these covenant calculations, exceeds retained earnings, as a result, retained earnings was free from any dividend restrictions as of December 31, 2010.

Dividends from Subsidiaries

Since NVE is a holding company, substantially all of its cash flow is provided by dividends paid to NVE by NPC and SPPC on their common stock, all of which is owned by NVE. 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 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. As a result of the Utilities' credit rating on their senior secured debt at investment grade by S&P and Moody's, these restrictions are suspended and no longer in effect so long as the debt remains investment grade by both rating agencies. 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 NVE could be jeopardized.

Credit Ratings

The liquidity of NVE and the Utilities, the cost and availability of borrowing by the Utilities under their respective credit facilities, the potential exposure of the Utilities to collateral calls under various contracts and the ability of the Utilities to acquire fuel and purchased power on favorable terms are all directly affected by the credit ratings for the companies' debt. NPC's and SPPC's senior secured debt is rated investment grade by three NRSRO's: Fitch, Moody's and S&P. As of December 31, 2010, the ratings are as follows:

		Rating Agency		
		Fitch	**Moody's**	**S&P**
NVE	Sr. Unsecured Debt	BB	Ba3	BB
NPC	Sr. Secured Debt	BBB*	Baa3*	BBB*
NPC	Sr. Unsecured Debt	BB+	Not rated	BB+
SPPC	Sr. Secured Debt	BBB*	Baa3*	BBB*

* Investment grade

Fitch's, Moody's and S&P's rating outlook for NVE, NPC and SPPC is Stable.

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. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be evaluated in the context of the applicable methodology, independently of all other ratings. The rating agencies provide ratings at the request of the company being rated and charge the company fees for their services.

Energy Supplier Matters

With respect to NPC's and SPPC's contracts for purchased power, NPC and SPPC purchase and sell electricity with counterparties under the WSPP agreement, an industry standard contract that NPC and SPPC use as members of the WSPP. The WSPP contract is posted on the WSPP website.

Under these contracts, a material adverse change, which includes a credit rating downgrade, in NPC and SPPC may allow the counterparty to request adequate financial assurance, which, if not provided within three business days, could cause a default. Most contracts and confirmations for purchased power have been modified or separate agreements have been made to either shorten the normal payment due date or require payment in advance of delivery in response to requests for financial assurance. 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, 2010 for all suppliers continuing to provide power under a WSPP agreement would approximate a $58.8 million payment or obligation to NPC. No amounts would be due to or from SPPC. These contracts qualify for the normal purchases scope exception as required by the Derivatives and Hedging Topic of the FASC, 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 Matters

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, which primarily means a credit rating downgrade below investment grade. 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 in response to requests for financial assurances. Forward physical gas supplies are purchased under index based pricing terms and as such do not carry forward mark-to-market exposure.

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. NPC has one transmission counterparty for which it is required to post cash collateral or a letter of credit in the event of credit rating downgrades. As of December 31, 2010, the maximum amount of additional collateral NPC would be required to post under these contracts in the event of credit rating downgrades was approximately $30.7 million. Of this amount, approximately $23.0 million would be required if NPC's Senior Unsecured ratings are downgraded from their current level and an additional amount of approximately $7.7 million would be required if NPC's Senior Secured ratings are downgraded to below investment grade.

Financial Gas Hedges

The Utilities enter into certain hedging contracts with various counterparties to manage the gas price risk inherent in purchased power and fuel contracts. As discussed under NPC's and SPPC's *Financing Transactions*, the Utilities shall reduce their availability under the Utilities' revolving credit facilities for net negative mark-to-market positions on hedging contracts with counterparties who are lenders under the revolving credit facilities provided that the reduction of availability under the revolving credit facilities shall at no time exceed 50% of the total commitments then in effect under the credit facilities. The calculation of NPC's and SPPC's negative mark-to-market exposure as of November 30, 2010 was approximately $28.3 million and $13.8 million, respectively, which amount was in effect for borrowings during the month of December 2010. Currently, the Utilities only have hedging contracts with counterparties who are also lenders on the revolving credit facilities; however, future contracts entered into with non-lenders may require the Utilities to post cash collateral in the event of a credit rating downgrade. Finally, in October 2009, the Utilities have suspended their hedging program, as such, expect their exposure to negative mark-to-market hedging transactions to decline.

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 NVE or the other Utility under any of their respective financing agreements. Certain of NVE's financing agreements, however, do contain cross-default provisions that would result in an event of default by NVE upon an event of default by the Utilities under their respective financing agreements. In addition, certain financing agreements of each of NVE 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 NVE or the Utilities may rectify or correct the situation before it becomes an event of default.

NEVADA POWER COMPANY

RESULTS OF OPERATIONS

NPC recognized net income of $185.9 million in 2010 compared to net income of $134.3 million in 2009 and $151.4 million in 2008. In 2010 NPC paid dividends to NVE of approximately $74 million. Details of NPC's operating results are further discussed below.

Gross margin is presented by NPC in order to provide information 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 a key factor 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 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 energy costs, provides a measure of income available to support the other operating expenses of NPC. For reconciliation to operating income, see Note 2, *Segment Information* of the Notes to Financial Statements. Gross margin changes are based primarily on general base rate adjustments (which are required by statute to be filed every three years).

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

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Operating revenues	$2,252,377	-7.1%	$2,423,377	4.7%	$2,315,427
Energy Costs:					
Fuel for power generation	588,419	0.1%	587,647	-22.3%	755,925
Purchased power	505,239	-19.5%	627,759	-7.8%	680,816
Deferred energy	94,843	-54.3%	207,611	-3088.5%	(6,947)
	$1,188,501	-16.5%	$1,423,017	-0.5%	$1,429,794
Gross Margin	$1,063,876	6.3%	$1,000,360	13.0%	$ 885,633

Gross margin increased for the year ended December 31, 2010, compared to the same period in 2009, primarily due to an increase in BTGR revenue as a result of NPC's 2008 GRC effective July 1, 2009. Partially offsetting the increase in gross margin was a decrease in usage per customer due to conservation programs, economic conditions and hotter than normal weather in May 2009.

NPC's gross margin increased for the year ended December 31, 2009 compared to the same period in 2008, primarily due to an increase in BTGR revenue as a result of NPC's 2008 GRC, effective July 1, 2009, and a slight increase in average customer growth. Partially offsetting the increase was a change in customer usage patterns which may be attributable to economic conditions, conservation programs, and the termination of various transmission service agreements.

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):

Operating Revenues

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Operating Revenues:					
Residential	$1,084,497	-5.2%	$1,143,836	7.5%	$1,064,510
Commercial	436,343	-8.6%	477,477	1.3%	471,236
Industrial	663,586	-7.9%	720,850	6.3%	678,117
Retail Revenues	2,184,426	-6.7%	2,342,163	5.8%	2,213,863
Other	67,951	-16.3%	81,214	-20.0%	101,564
Total Operating Revenues	$2,252,377	-7.1%	$2,423,377	4.7%	$2,315,427
Retail sales in thousands of MWhs	20,642	-1.5%	20,957	-2.0%	21,381
Average retail revenue per MWh	$ 105.82	-5.3%	$ 111.76	7.9%	$ 103.54

NPC's retail revenues decreased for the year ended December 31, 2010 compared to the same period in 2009 primarily due to decreased energy rates from NPC's various BTER quarterly updates, the annual Deferred Energy case effective October 1, 2010 and the expiration of the Western Energy Crisis Amortization rate on May 1, 2010 (See Note 3, *Regulatory Actions* of the Notes to the Financial Statements). Also contributing to the decrease was a decrease in customer usage due to conservation programs, economic conditions and hotter than normal weather in May 2009. These decreases were partially offset by increases in general rates as a result of NPC's 2008 GRC, effective July 1, 2009, (See Note 3, *Regulatory Actions* of the Notes to the Financial Statements). Average residential, commercial, and industrial customers increased by 0.4%, 0.8% and 0.3%, respectively.

NPC's retail revenues increased for the year ended December 31, 2009 compared to the same period in 2008, primarily due to increases in rates as a result of NPC's GRC effective July 1, 2009, partially offset by decreased rates as a result of NPC's various BTER quarterly cases and deferred energy cases. For further discussions on NPC's various rate cases see Note 3, *Regulatory Actions* of the Notes to the Financial Statements. The overall rate increase was partially offset by decreased usage caused by changes in customer usage patterns, which may be attributable to economic conditions and/or conservation efforts, and cooler summer weather during 2009. Average residential, commercial, and industrial customers increased by 0.1%, 0.4% and 1.5%, respectively, compared to prior year.

Other Operating Revenues decreased for the year ended December 31, 2010 compared to the same period in 2009. The decrease is primarily due to the expiration of a significant transmission agreement with Calpine Energy Services and decreases in sales for resale.

Other Operating Revenues decreased for the year ended December 31, 2009 compared to the same period in 2008. The decrease is primarily due to the termination of several transmission agreements, including a transmission agreement related to the Higgins Generating Station which was purchased by NPC in October 2008.

Energy Costs

Energy Costs include Fuel for Generation and Purchased Power. Energy costs are dependent upon several factors which may vary by season or period. As a result, NPC's usage and average cost per MWh of Fuel for Generation versus Purchased Power to meet demand can vary significantly. Factors that may affect Energy Costs include, but are not limited to:

- Weather;
- Generation efficiency;
- Plant outages;
- Total system demand;
- Resource constraints;
- Transmission constraints;
- Natural gas constraints;
- Long term contracts; and
- Mandated power purchases.

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Energy Costs					
Fuel for Generation	$ 588,419	0.1%	$ 587,647	-22.3%	$ 755,925
Purchased Power	505,239	-19.5%	627,759	-7.8%	680,816
Energy Costs	$1,093,658	-10.0%	$1,215,406	-15.4%	$1,436,741
MWhs					
MWhs Generated (in thousands)	15,405	-6.2%	16,431	9.8%	14,968
Purchased Power (in thousands)	6,351	11.5%	5,697	-20.8%	7,190
Total MWhs	21,756	-1.7%	22,128	-0.1%	22,158
Average cost per MWh					
Average fuel cost per MWh of Generated Power	$ 38.20	6.8%	$ 35.76	-29.2%	$ 50.50
Average cost per MWh of Purchased Power	$ 79.55	-27.8%	$ 110.19	16.4%	$ 94.69
Average cost per MWh	$ 50.27	-8.5%	$ 54.92	-15.3%	$ 64.84

Energy Costs decreased for the year ended December 31, 2010 compared to the same period in 2009 primarily due to a decrease in costs associated with hedging activities offset by a slight increase in natural gas prices. In 2010, self generation, which is primarily gas fired generating units, satisfied 71% of NPC's system load.

- Fuel for generation costs increased for the year ended December 31, 2010 primarily due to higher cost of natural gas and the change in the method of allocating electric tolling option expense between fuel for generation and purchased power which had no impact on gross margin or operating income, partially offset by a decrease in volume and a decrease in costs associated with hedging activities. MWhs generated decreased for the year ended December 31, 2010 primarily due to planned outages within internal generation in the early part of the year. The average price per MWh of generated power increased for the year due to an increase in natural gas costs and the change in method of allocating electric tolling option expense, partially offset by a decrease in costs associated with hedging activities.
- Purchased power costs and the average cost per MWh of purchased power decreased for the year ending December 31, 2010 primarily due to a decrease in costs associated with hedging activities and the change in method of allocating electric tolling option expense, as discussed above, partially offset by an increase in renewable energy purchases and capacity contracts. Purchased power MWhs increased for the year ending December 31, 2010 due to renewable energy purchases and plant outages within internal generation.

Energy Costs decreased for the year ended December 31, 2009 compared to the same period in 2008 primarily due to a decrease in natural gas prices coupled with an increase in self generation, partially offset by an increase in costs associated with hedging activities. In 2009, self generation, which is primarily gas fired generating units, satisfied 74% of NPC's system load.

- Fuel for generation, as a component of energy costs decreased primarily due to a decrease in natural gas prices.
- Purchased power, as a component of energy costs, as well as the average cost per MWh, decreased primarily due to a decrease in natural gas prices and a decrease in volume, partially offset by an increase in costs associated with hedging activities. The average cost per MWh increased primarily due to increased costs associated with hedging activities, partially offset by a decrease in natural gas prices.

Deferred Energy

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Deferred energy	$94,843	-54.3%	$207,611	-3088.5%	$(6,947)

Deferred energy 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 also includes the current amortization of fuel and purchased power costs previously deferred. See Note 3, *Regulatory Actions*, of the Notes to Financial Statements for further detail of deferred energy balances.

Amounts for 2010, 2009 and 2008 include amortization of deferred energy of $1.2 million, $42.0 million and $132.6 million, respectively; and an over-collection of amounts recoverable in rates of $93.6 million and $165.6 million in 2010 and 2009, respectively, and an under-collection of $139.6 million in 2008.

Other Operating Expenses

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Other operating expense	$260,535	-6.9%	$279,865	12.3%	$249,236
Maintenance expense	$ 71,759	1.0%	$ 71,019	12.2%	$ 63,282
Depreciation and amortization	$226,252	4.8%	$215,873	26.2%	$171,080

Other operating expense decreased for the year ended December 31, 2010, compared to the same period in 2009, primarily due to lower employee pension and benefit expenses, costs incurred in 2009 related to severance programs, as discussed further in Note 17, *Severance Programs*, of the Notes to Financial Statements and a reduction in bad debt expense. In addition, other operating expenses decreased as a result of costs associated with the REPR. Beginning in 2010, these amounts are reported net of their related operating expense; as such, REPR amounts no longer effect operating expense. In 2009 and 2008, REPR costs were not material and were included in operating expenses with a corresponding amount recorded to revenues and had no effect on net income. The decrease was partially offset by increases in amortization of DSM programs and higher operating leases.

Other operating expense increased for the year ended December 31, 2009, compared to the same period in 2008, primarily due to higher pension and other post retirement benefit expenses, costs related to severance programs, as discussed further in Note 17, *Severance Programs*, of the Notes to Financial Statements, costs associated with renewable energy programs, amortization of new DSM programs, higher operating leases and operating expenses for the Higgins Generating Station acquired in October 2008.

Maintenance expense increased for the year ended December 31, 2010, compared to the same period in 2009, primarily due to termination of a long-term service agreement and maintenance at the Higgins, Harry Allen and Silverhawk Generating Stations. This increase was partially offset by planned maintenance outages that occurred in 2009 at the Reid Gardner and Clark Generating Stations.

Maintenance expense increased for the year ended December 31, 2009, compared to the same period in 2008, due to the addition of the Higgins Generating Station and increased scheduled maintenance for Navajo, Lenzie and Silverhawk Generating Stations in 2009, partially offset by lower maintenance cost for the Reid Gardner Generating Station, attributable to a major turbine overhaul in 2008.

Depreciation and amortization expenses increased for the year ended December 31, 2010, compared to the same period in 2009, primarily due to regular system growth.

Depreciation and amortization expenses increased for the year ended December 31, 2009, compared to the same period in 2008, as a result of increases in plant in service, primarily due to the completion of the Clark Peaking units and the addition of the Higgins Generating Station in the latter part of 2008.

Interest Expense

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Interest expense (net of AFUDC-debt: $21,433, $17,184 and $20,063)	$214,367	-5.3%	$226,252	21.1%	$186,822

Interest expense decreased for the year ended December 31, 2010 compared to the same period in 2009 primarily due to the expiration in 2009 of amortization costs related to debt issues and redemptions, an increase in AFUDC due to construction at the Harry Allen Generating Station, lower interest on variable rate debt and the partial redemption of Series 1997A in December 2009 and the redemptions of Series 1995 A, B, C, and D in October 2010. Partially offsetting this decrease was higher credit facility balances in 2010, and increased interest expense due to the issuance of $500 million, Series V, General and Refunding Mortgage Notes in March 2009 and the issuance of $250 million, Series X, General and Refunding Mortgage Notes in September 2010. See Note 6, *Long Term Debt*, for further discussion.

Interest expense increased for the year ended December 31, 2009 compared to the same period in 2008 primarily due to the issuance of the following debt:

- $500 million Series S General and Refunding Mortgage Notes in July 2008;
- $125 million Series U General and Refunding Mortgage Notes in January 2009; and
- $500 million Series V General and Refunding Mortgage Notes in March 2009.

Partially offsetting this increase was lower interest on variable rate debt, interest charges related to IRS income tax settlements in 2008, interest expense associated with refunds for construction advances in 2008, lower AFUDC-debt during construction due to the completion of the Clark Peaking Units in the latter part of 2008 and the expiration in 2009 of amortization of costs related to debt issues and redemptions.

Other Income (Expense)

	2010		2009		2008
	Amount	**Change from Prior Year**	**Amount**	**Change from Prior Year**	**Amount**
Interest income (expense) on regulatory items	$ (3,169)	-191.5%	$ 3,463	-52.8%	$ 7,342
AFUDC-equity	$ 25,229	20.0%	$ 21,025	-18.9%	$ 25,917
Other income	$ 15,541	-20.9%	$ 19,658	18.2%	$ 16,631
Other expense	$(12,946)	-29.3%	$(18,320)	79.2%	$(10,221)

The change in interest income (expense) on regulatory items for the year ended December 31, 2010, compared to the same period in 2009, is primarily due to over-collected deferred energy balances. See Note 3, *Regulatory Actions*, for further details of deferred energy balances.

Interest income (expense) on regulatory items decreased for the year ended December 31, 2009 compared to the same period in 2008 due to lower carrying charges associated with NPC's Western Energy Crisis Rate Case, which began June 1, 2007, and overall lower deferred energy balances. See Note 3, *Regulatory Actions*, of the Notes to Financial Statements for further details of deferred energy balances.

AFUDC-equity increased for the year ended December 31, 2010 compared to 2009 primarily due to construction at the Harry Allen Generating Station.

AFUDC-equity decreased for the year ended December 31, 2009 compared to 2008 primarily due to completion of Clark Peaking Units.

Other income decreased for the year ended December 31, 2010, compared to the same period in 2009, due to settlement gains for outstanding legal matters in 2009 associated with the Natural Gas Provider case, as discussed further in Note 13, *Commitments and Contingencies* of the Notes to Financial Statements. This decrease was partially offset by higher interest income on investments in 2010.

Other income increased for the year ended December 31, 2009 compared to the same period in 2008 due to the settlement of outstanding legal matters associated with the Natural Gas Provider case, as discussed further in Note 13, *Commitments and Contingencies* in the Notes to Financial Statements, and interest received on income tax refunds. These were partially offset by expiration of the amortization of gains associated with the disposition of property, lower interest income on investments and income earned in 2008 as a result of the settlement with Calpine, and the subsequent gain on sale of the stock received, as discussed further in Note 13, *Commitments and Contingencies* in the Notes to Financial Statements.

Other expense decreased for the year ended December 31, 2010, compared to the same period in 2009, primarily due to charges in 2009 resulting from NPC's GRC in 2009, a disallowance related to contract pricing for energy in 2009, partially offset by adjustments for the settlement of the deferred energy rate case in 2010.

Other expense increased for the year ended December 31, 2009 compared to the same period in 2008 primarily due to adjustments resulting from NPC's GRC and a disallowance related to contract pricing for energy. The increase in other expense was partially offset by lower advertising expenses in 2009.

ANALYSIS OF CASH FLOWS

NPC's cash flows increased during 2010 compared to 2009 due to an increase in cash from operating activities and a reduction in cash used for investing activities, partially offset by a decrease in cash from financing activities.

Cash From Operating Activities. The increase in cash from operating activities is primarily due to increased revenues as a result of the rate increase in NPC's 2008 GRC, decreased purchased power costs, a decrease in funding for pension plans, and a refund to a transmission customer in 2009, partially offset by BTER, WECA and DEAA rate reductions.

Cash Used By Investing Activities. Cash used by investing activities decreased mainly due to the slowdown in construction for infrastructure, and proceeds from the sale of property.

Cash From Financing Activities. Cash from financing activities decreased primarily due to a reduction in the issuance of debt compared to 2009 and an increase in payments on NPC's revolving credit facility, partially offset by lower dividend payments to NVE.

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, capital expenditures and the payment of interest on NPC's outstanding indebtedness. Operating cash flows can be significantly influenced by factors such as weather, regulatory outcome, and economic conditions. Available liquidity as of December 31, 2010 was as follows (in millions):

Available Liquidity as of December 31, 2010

	NPC
Cash and Cash Equivalents	$ 60.1
Balance available on Revolving Credit Facility(1)	585.3
Less reduction for hedging transactions(2)	(28.3)
	$617.1

(1) As of February 23, 2011, NPC had approximately $569.6 million available under its revolving credit facility which includes reductions for hedging transactions and letters of credits, as discussed below under *Financing Transactions*.

(2) Reduction for hedging transactions reflects balances as of November 30, 2010.

NPC attempts to maintain its cash and cash equivalents in highly liquid investments, such as U.S. Treasury Bills and bank deposits. In addition to cash on hand, NPC may use its revolving credit facility in order to meet its liquidity needs. Alternatively, depending on the usage of the revolving credit facility, NPC may issue debt, subject to certain restrictions as discussed in *Factors Affecting Liquidity*, *Ability to Issue Debt*, below.

NPC's significant debt maturities in 2011 and 2012 include its $350 million 8.25% General and Refunding Notes, Series A, which mature on June 1, 2011 and its $130 million 6.50% General and Refunding Mortgage Notes, Series I, which mature April 15, 2012. In addition, NPC is required to redeem approximately $98.1 million of its variable rate debt, due 2020, prior to ON Line's commercial operation date, expected in late 2012. As of February 23, 2011, NPC has no borrowings on its revolving credit facility, not including letters of credit.

NPC anticipates that it will be able to meet short-term operating costs, such as fuel and purchased power costs, with internally generated funds, including recovery of deferred energy, and the use of its revolving credit facility. Furthermore, in order to fund long term capital requirements and maturing debt obligations, NPC will use a combination of internally generated funds, its revolving credit facility, the issuance of long-term debt and/or capital contributions from NVE. However, if energy costs rise at a rapid rate and NPC does not recover the cost of fuel and purchased power in a timely manner, if operating costs are not recovered in a timely manner or NPC were to experience a credit rating downgrade resulting in the posting of collateral as discussed below under *Gas Supplier Matters* and *Financial Gas Hedges,* the amount of liquidity available to NPC could be significantly less. In order to maintain sufficient liquidity, NPC may be required to further delay capital expenditures, re-finance debt or obtain funding through an equity issuance by NVE.

The ability to issue debt, as discussed later, is subject to certain covenant calculations which include consolidated net income of NVE and the Utilities. As a result of these covenant calculations and the seasonality of the Utilities' business, the ability to issue debt can vary from quarter to quarter, and the Utilities may not be able to fully utilize the availability on their revolving credit facilities.

In 2010, NPC's credit ratings on its senior secured debt remained at investment grade (see *Credit Ratings* below). In 2010, NPC did not experience any limitations in the credit markets, nor does NPC expect any significant limitations in 2011. However, disruptions in the banking and capital markets not specifically related to NPC may affect its ability to access funding sources or cause an increase in the interest rates paid on newly issued debt.

In 2010, NPC paid dividends to NVE of approximately $74 million.

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, recently completed Financing Transactions and Factors Affecting Liquidity, including our ability to obtain debt on favorable terms.

Capital Structure

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

	2010		2009	
	Amount	Percent of Total Capitalization	Amount	Percent of Total Capitalization
Current Maturities of Long-Term Debt	$ 355,929	5.6%	$ 119,474	1.9%
Long-Term Debt	3,221,833	50.8%	3,535,440	56.1%
Shareholder's Equity	2,761,632	43.6%	2,650,039	42.0%
Total	$6,339,394	100%	$6,304,953	100%

Capital Requirements

Construction Expenditures

NPC's cash requirement for construction expenditures for 2011 is projected to be $355.3 million. NPC's cash requirements for construction expenditures for 2011 through 2015 are projected to be $1.4 billion. Cash used by investing activities for the years ended 2010, 2009 and 2008 were approximately $449.6 million, $615.4 million and $1.3 billion, respectively. To fund future capital projects, NPC may meet such financial obligations with a combination of internally generated funds, the use of its revolving credit facilities, the issuance of long-term debt, and if necessary, capital contributions from NVE.

Contractual Obligations

The table below provides NPC's consolidated contractual obligations, as of December 31, 2010, 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. Certain contracts contain variable factors which required NPC to estimate the obligation depending on the final variable amount. Actual amounts could differ. The table does not include estimated construction expenditures described above, except for major capital projects for which NPC has executed contracts by December 31, 2010. Additionally, at December 31, 2010, NPC has recorded an uncertain tax liability of $25.5 million as required by the accounting guidance for Uncertainty in Income Taxes Topic of the FASC, all of which is classified as non-current. NPC is unable to make a reasonably reliable estimate of the period of cash payments to relevant tax authorities; consequently, none of the uncertain tax liability is included in the contractual obligations table below (dollars in thousands):

	Payment Due by Period						
	2011	2012	2013	2014	2015	Thereafter	Total
Long-Term Debt Maturities	$ 350,000	$ 130,000	$ -	$125,000	$ 250,000	$ 2,678,775	$ 3,533,775
Long-Term Debt Interest Payments	209,111	191,095	188,630	179,796	165,336	1,599,077	2,533,045
Purchased Power	327,200	330,497	328,093	310,310	315,565	2,431,414	4,043,079
Purchase Power - Not Commercially Operable(1)	12,651	76,741	84,812	159,407	218,680	4,830,319	5,382,610
Coal and Natural Gas	362,046	149,013	38,461	34,406	35,220	147,253	766,399
Transportation(2)	61,645	82,087	118,767	114,875	111,375	1,702,092	2,190,841
Long-Term Service Agreements(3)	20,218	15,180	14,285	14,758	15,140	65,299	144,880
Capital Projects(4)	227,969	66,964	42,986	-	-	-	337,919
Operating Leases	11,784	9,799	9,275	8,279	6,178	86,099	131,414
Capital Leases	9,976	9,828	9,845	7,435	4,831	66,030	107,945
Total Contractual Cash Obligations	$1,592,600	$1,061,204	$835,154	$954,266	$1,122,325	$13,606,358	$19,171,907

(1) Represents estimated payments under renewable energy power purchase contracts, which have been approved by the PUCN and are contingent upon the developers obtaining commercial operation and their ability to deliver energy.

(2) Includes the TUA with GBT which is contingent upon final construction costs and reaching commercial operation, which is expected in late 2012.

(3) Amounts based on estimated usage.

(4) Capital projects include construction costs at the Harry Allen Generating Station and NV Energize and NPC's requirement to purchase the undepreciated cost of capital of Reid Gardner #4 from CDWR. Additionally, NPC, as a joint owner, has obligations regarding the construction of ON Line.

Pension and Other Postretirement Benefit Plan Matters

NVE has a qualified pension plan and other postretirement benefits plan which cover substantially all employees of NVE, NPC and SPPC. The annual net benefit cost for the plans is expected to decrease in 2011 by approximately $7.3 million compared to the 2010 cost of $36.2 million. As of December 31, 2010, the measurement date, the plan was under funded under the provisions of the Compensation Retirement Benefits Topic of the FASC. Refer to Note 11, *Retirement Plan and Post-Retirement Benefits*, of the Notes to Financial Statements. During 2010, NVE funded a total of $40 million to the trusts established for these plans. At the present time it is not expected that additional funding will be required in 2011 to meet the minimum funding level requirements defined by the Pension Protection Act of 2006. However, NVE and the Utilities have included in their 2011 assumptions funding levels similar to the 2010 funding. The amounts to be contributed in 2011 may change subject to market conditions.

Financing Transactions

General and Refunding Mortgage Notes, Series X

In September 2010, NPC issued and sold $250 million of its 5.375% General and Refunding Mortgage Notes, Series X, due 2040. Of the approximately $247 million in net proceeds, $231 million was used in October, 2010 to redeem (i) approximately $206 million in aggregate principal amount of fixed rate unsecured tax-exempt local furnishing (''two-county'') bonds issued for NPC's benefit and (ii) approximately $20 million unsecured tax-exempt pollution control refunding revenue bonds issued for NPC's benefit. The remaining net proceeds of approximately $16 million were used to repay amounts outstanding under NPC's revolving credit facility.

$600 Million Revolving Credit Facility

In April 2010, NPC terminated its $589 million secured revolving credit facility which would have expired in November 2010 and replaced it with a $600 million secured revolving credit facility, maturing in April 2013. The fees on the $600 million revolving credit facility for the unused portion and on the amounts borrowed have increased from the prior facility reflecting current market conditions. The Administrative Agent for the facility remains Wells Fargo Bank, National Association (formerly Wachovia Bank, National Association). The rate for outstanding loans under the revolving credit facility will be at either an applicable base rate (defined as the highest of the Prime Rate, the Federal Funds Rate plus ½ of 1.0% and the LIBOR Base Rate plus 1.0%) plus a margin, or a LIBOR rate plus a margin. The margin varies based upon NPC's credit rating by S&P and Moody's. Currently, NPC's applicable base rate margin is 1.25% and the LIBOR rate margin is 2.25%. The rate for outstanding letters of credit will be at the LIBOR rate margin plus a fee for the issuing bank.

The $600 million revolving credit facility contains a provision which reduces the availability under the credit facility by the negative mark-to-market exposure for hedging transactions with credit facility lenders or their energy trading affiliates. The reduction in availability limits the amount that NPC can borrow or use for letters of credit and would require that NPC prepay any amount in excess of that limitation. The amount of the reduction is calculated by NPC on a monthly basis, and after calculating such reduction, the NPC Credit Agreement provides that the reduction in availability under the revolving credit facility to NPC shall not exceed 50% of the total commitments then in effect under the revolving credit facility.

The NPC Credit Agreement contains one financial maintenance covenant that 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. In the event that NPC did not meet the financial maintenance covenant or there is an event of default, the NPC Credit Agreement would restrict dividends to NVE. Moreover, so long as NPC's senior secured debt remains rated investment grade by S&P and Moody's (in each case, with a stable or better outlook), a representation concerning no material adverse change in NPC's business, assets, property or financial condition would not be a condition to the availability of credit under the facility. In the event that NPC's senior secured debt rating were rated below investment grade by either S&P or Moody's, or investment grade by either S&P or Moody's but with a negative outlook, a representation concerning no material adverse change in NPC's business, assets, property or financial condition would be a condition to borrowing under the revolving credit facility.

Factors Affecting Liquidity

Ability to Issue Debt

NPC's ability to issue debt is impacted by certain factors such as financing authority from the PUCN, financial covenants in its financing agreements and revolving credit facility agreements, and the terms of certain NVE debt. As of December 31, 2010, the most restrictive of the factors below is the PUCN authority. As such, NPC may issue up to $725 million in long-term debt, in addition to the use of its existing credit facility. However, depending on NVE's or SPPC's issuance of long-term debt or the use of the Utilities' revolving credit facilities, the PUCN authority may not remain the most restrictive factor. The factors affecting NPC's ability to issue debt are further detailed below:

a. Financing authority from the PUCN - As of December 31, 2010, NPC has financing authority from the PUCN for the period ending December 31, 2013, consisting of authority (1) to issue additional long-term debt securities of up to $725 million; (2) to refinance up to approximately $672.5 million of long-term debt securities; and (3) ongoing authority to maintain a revolving credit facility of up to $1.3 billion.

b. Financial covenants within NPC's financing agreements - Under its $600 million revolving credit facility, NPC must 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. Based on December 31, 2010 financial statements, NPC was in compliance with this covenant and could incur up to $2.3 billion of additional indebtedness.

   All other financial covenants contained in NPC's financing agreements are suspended, as NPC's senior secured debt is rated investment grade. However, if NPC's senior secured debt ratings fall below investment grade by either Moody's or S&P, NPC would again be subject to the limitations under these additional covenants; and

c. Financial covenants within NVE's financing agreements - As discussed in NVE's *Ability to Issue Debt*, NPC is also subject to NVE's cap on additional consolidated indebtedness of $1.9 billion.

Ability to Issue General and Refunding Mortgage Securities

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 NPC's General and Refunding Mortgage Indenture (''Indenture'').

The Indenture creates a lien on substantially all of NPC's properties in Nevada. As of December 31, 2010 $4.0 billion of NPC's General and Refunding Mortgage Securities were outstanding. NPC had the capacity to issue $706.6 million of General and Refunding Mortgage Securities as of December 31, 2010. 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.

Property additions include plant in service and specific assets in CWIP. The amount of bond capacity listed above does not include eligible property in CWIP.

NPC also has the ability to release property from the lien of the mortgage indenture on the basis of net property additions, cash and/or retired bonds. To the extent NPC releases property from the lien of NPC's Indenture, it will reduce the amount of securities issuable under the Indenture.

Credit Ratings

The liquidity of NPC, the cost and availability of borrowing by NPC under its credit facility, the potential exposure of NPC to collateral calls under various contracts and the ability of NPC to acquire fuel and purchased power on favorable terms are all directly affected by the credit ratings for NPC's debt. NPC's senior secured debt is rated investment grade by three NRSRO's: Fitch, Moody's and S&P. In May 2010, Fitch upgraded the ratings for NPC's senior secured debt to BBB from BBB- and the senior unsecured debt to BB+ from BB, and revised the rating outlook from positive to stable. As of December 31, 2010, the ratings are as follows:

		Rating Agency		
		Fitch	Moody's	S&P
NPC	Sr. Secured Debt	BBB*	Baa3*	BBB*
NPC	Sr. Unsecured Debt	BB+	Not rated	BB+

* Investment grade

Fitch's, Moody's and S&P's rating outlook for NPC is Stable.

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. Each security rating agency has its own methodology for assigning ratings, and accordingly, each rating should be evaluated in the context of the applicable methodology, independently of all other ratings. The rating agencies provide ratings at the request of the company being rated and charge the company fees for their services.

Energy Supplier Matters

With respect to NPC's contracts for purchased power, NPC purchases and sells electricity with counterparties under the WSPP agreement, an industry standard contract that NPC uses as a member of the WSPP. The WSPP contract is posted on the WSPP website.

Under these contracts, a material adverse change, which includes a credit rating downgrade, in NPC may allow the counterparty to request adequate financial assurance, which, if not provided within three business days, could cause a default. Most contracts and confirmations for purchased power have been modified or separate agreements have been made to either shorten the normal payment due date or require payment in advance of delivery in response to requests for financial assurance. 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, 2010 for all suppliers continuing to provide power under a WSPP agreement would approximate a $58.8 million payment or obligation to NPC. These contracts qualify for the normal purchases scope exception as defined by the Derivatives and Hedging Topic of the FASC, 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 Matters

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, which primarily means a credit rating downgrade below investment grade. 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 in response to requests for financial assurances. Forward physical gas supplies are purchased under index based pricing terms and as such do not carry forward mark-to-market exposure.

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. NPC has one transmission counterparty for which it is required to post cash collateral or a letter of credit in the event of credit rating downgrades. As of December 31, 2010, the maximum amount of additional collateral NPC would be required to post under these contracts in the event of credit rating downgrades was approximately $30.7 million. Of this amount, approximately $23.0 million would be required if NPC's Senior Unsecured ratings are downgraded from their current level and an additional amount of approximately $7.7 million would be required if NPC's Senior Secured ratings are downgraded to below investment grade.

Financial Gas Hedges

NPC enters into certain hedging contracts with various counterparties to manage the gas price risk inherent in purchased power and fuel contracts. As discussed under NPC's Financing Transactions, the availability under NPC's revolving credit facility is reduced by the amount of net negative mark-to-market positions on hedging contracts with counterparties who are lenders to the revolving credit facility, provided that the reduction in availability under the revolving credit facility shall at no time exceed 50% of the total commitments then in effect under the revolving credit facility. The calculation of NPC's negative mark-to-market exposure as of November 30, 2010 was approximately $28.3 million, which amount was in effect for borrowings during the month of December 2010. Currently, NPC only has hedging contracts with counterparties who are also lenders on the revolving credit facility; however, future contracts entered into with non-lenders may require NPC to post cash collateral in the event of a credit rating downgrade. Finally, in October 2009, NPC suspended its hedging program, as such, expects its exposure to negative mark-to-market positions to decline.

Cross Default Provisions

None of the financing agreements of NPC contains a cross-default provision that would result in an event of default by NPC upon an event of default by NVE 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 $72.4 million for the year ended December 31, 2010, compared to net income of $73.1 million in 2009 and a net income of $90.6 million in 2008. In 2010, SPPC paid dividends to NVE of approximately $54 million and at December 31, 2010 had a dividend payable of $54 million, which was subsequently paid in January 2011. In February 2011, SPPC declared a dividend of approximately $38 million to NVE. Details of SPPC's operating results are further discussed below.

Gross margin is presented by SPPC in order to provide information 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 a key factor 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 energy costs, provides a measure of income available to support the other operating expenses of SPPC. For reconciliation to operating income, see Note 2, *Segment Information,* in the Notes to Financial Statements. Gross margin changes are based primarily on general base rate adjustments (which are required to be filed by statute every three years).

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

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Operating Revenues:					
Electric	$ 836,879	-12.6%	$ 957,130	-4.5%	$1,002,674
Gas	190,943	-7.0%	205,263	-2.2%	209,987
	$1,027,822	-11.6%	$1,162,393	-4.1%	$1,212,661
Energy Costs:					
Fuel for power generation	$ 233,065	-20.8%	$ 294,121	3.8%	$ 283,342
Purchased power	143,642	9.7%	130,977	-55.4%	293,527
Gas purchased for resale	137,702	-10.4%	153,607	-9.9%	170,468
Deferred energy - electric - net	8,475	-88.5%	73,829	5618.7%	1,291
Deferred energy - gas - net	9,789	28.2%	7,636	-265.7%	(4,609)
	$ 532,673	-19.3%	$ 660,170	-11.3%	$ 744,019
Energy Costs by Segment:					
Electric	$ 385,182	-22.8%	$ 498,927	-13.7%	$ 578,160
Gas	147,491	-8.5%	161,243	-2.8%	165,859
	$ 532,673	-19.3%	$ 660,170	-11.3%	$ 744,019
Gross Margin by Segment:					
Electric	$ 451,697	-1.4%	$ 458,203	7.9%	$ 424,514
Gas	43,452	-1.3%	44,020	-0.2%	44,128
	$ 495,149	-1.4%	$ 502,223	7.2%	$ 468,642

Electric gross margin decreased for the year ended December 31, 2010, compared to the same period in 2009 primarily due to a decrease in customer usage as a result of milder summer weather, conservation programs and economic conditions. In addition, gross margin decreased as a result of revenue associated with the REPR. REPR is a rate mechanism designed to provide rebates to customers for the implementation of approved renewable projects. Beginning in 2010, these amounts are reported net of their related operating expense; as such, REPR amounts do not affect gross margin. In 2009 and 2008, REPR charges were not material and were included in revenues, which therefore increased gross margin, but did not effect operating income or net income. Partially offsetting the decrease in gross margin was an adjustment for California revenues upon a final filing in 2010 with the CPUC in regards to the Rate Reduction Certificates Series 1999-1.

Electric gross margin increased for the year ended December 31, 2009, compared to the same period in 2008, primarily due to an increase in BTGR revenue as a result of SPPC's 2007 GRC, effective July 1, 2008, and a slight increase in average customer growth. Partially offsetting the increase was a change in customer usage patterns which may be attributable to economic conditions, conservation programs, a decrease in short-term transmission revenue, and the switching of certain mining customers to DOS.

Gas gross margin decreased for the year ended December 31, 2010, compared to the same period in 2009 primarily due to decreased customer usage as a result of warmer weather.

Gas gross margin did not change materially for the year ended December 31, 2009 compared to the same period in 2008.

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 Revenues

	2010		2009		2008
	Amount	Change from Prior year	Amount	Change from Prior year	Amount
Electric Operating Revenues:					
Residential	$303,737	-12.1%	$345,455	1.3%	$ 340,972
Commercial	321,599	-15.8%	381,805	-1.3%	386,678
Industrial	178,855	-10.4%	199,510	-17.1%	240,711
Retail revenues	804,191	-13.2%	926,770	-4.3%	968,361
Other	32,688	7.7%	30,360	-11.5%	34,313
Total Revenues	$836,879	-12.6%	$957,130	-4.5%	$1,002,674
Retail sales in thousands of MWhs	8,081	-1.0%	8,162	-4.6%	8,560
Average retail revenue per MWh	$ 99.52	-12.4%	$ 113.55	0.4%	$ 113.13

SPPC's retail revenues decreased for the year ended December 31, 2010 compared to the same period in 2009 primarily due to decreases in retail rates as a result of SPPC's various BTER quarterly updates and the annual Deferred Energy case effective October 1, 2010 (see Note 3, *Regulatory Actions* of the Notes to Financial Statements) and a decrease in customer usage as a result of milder summer weather, conservation programs and economic conditions. These decreases were partially offset by increased industrial usage primarily from a gold mining customer who resumed full operation in October 2009. The average number of residential and commercial customers increased 0.2% and 0.1%, respectively, while industrial customers decreased 1.8%.

SPPC's retail revenues decreased in 2009 compared to 2008 primarily due to lower industrial revenue and decreased customer usage due to milder weather during the first three quarters of 2009. Industrial revenues decreased primarily due to the transition of Cortez Mine to distribution only service effective November 1, 2008 and a retail service agreement with Newmont beginning in June 2008. In addition, one large commercial customer moved to standby service effective November 1, 2009. Lower rates as a result of the BTER quarterly update and the annual Deferred Energy cases effective October 1, 2009 also contributed to the decrease. These decreases were partially offset by increased retail rates as a result of SPPC's BTGR case effective July 1, 2008 (see Note 3, *Regulatory Actions* of the Notes to Financial Statements). The average number of residential customers decreased 0.1% and the average number of commercial and industrial customers increased 1.3% and 1.8%, respectively.

In 2007, SPPC and Newmont entered into a wholesale power sale agreement and a new form of retail service, whereby Newmont will sell the electrical output from its generating plant to SPPC for at least 15 years under a long-term wholesale purchase power agreement and remain a retail customer of SPPC during at least that period under the terms of the retail service agreement and pursuant to a new rate schedule. The terms of these contracts became effective on June 1, 2008, at which point Newmont moved to a new retail service agreement at a reduced energy rate, which resulted in decreased electric revenues.

Electric Operating Revenues - Other increased for the year ended December 31, 2010 compared to the same period in 2009 primarily due to an adjustment for California revenues upon a final filing in 2010 with the CPUC in regards to the Rate Reduction Certificates Series 1999-1.

Electric Operating Revenues - Other decreased in 2009 compared to 2008 primarily due to decreased sales of wholesale power to other utilities and decreased transmission revenues due to the termination of several transmission service agreements.

Gas Operating Revenues

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Gas Operating Revenues:					
Residential	$102,923	-11.8%	$116,680	1.6%	$114,845
Commercial	45,547	-12.7%	52,186	0.0%	52,163
Industrial	14,802	-15.2%	17,458	-10.5%	19,514
Retail revenues	163,272	-12.4%	186,324	-0.1%	186,522
Wholesale	25,233	52.4%	16,560	-21.0%	20,956
Miscellaneous	2,438	2.5%	2,379	-5.2%	2,509
Total Revenues	$190,943	-7.0%	$205,263	-2.2%	$209,987
Retail sales in thousands of Dths	14,739	-2.0%	15,046	-0.2%	15,070
Average retail revenues per Dth	$ 11.08	-10.5%	$ 12.38	0.0%	$ 12.38

SPPC's retail gas revenues decreased for the year ended December 31, 2010 as compared to the same period in 2009, primarily due to decreased retail rates and decreased customer usage. Retail rates decreased as a result of SPPC's various BTER quarterly updates and the annual Natural Gas and Propane Deferred Rate Cases effective October 1, 2009 and 2010. See Note 3, *Regulatory Actions* of the Notes to Financial Statements. Customer usage decreased due to warmer weather in the fourth quarter compared to prior year. The average number of retail customers increased by 0.8%.

Retail gas revenues decreased slightly in 2009 as compared to 2008. Retail rates decreased as a result of SPPC's BTER updates during the first and fourth quarters of 2009 and the 2009 Natural Gas and Propane Deferred Rate Case effective October 1, 2009. These decreases were offset by increases resulting from SPPC's BTER updates during the second and third quarters. See Note 3, *Regulatory Actions* of the Notes to Financial Statements. Customer usage decreased during the first and second quarter of 2009 due to warmer weather and increased during the fourth quarter due to much colder 2009 temperatures. The average number of retail customers increased by 0.4%.

Wholesale revenues increased for the year ended December 31, 2010, compared to the same period in 2009 primarily due to sales related to the optimization of pipeline capacity and excess availability of gas for wholesale sales.

Wholesale revenues decreased in 2009 compared to 2008 primarily due to decreased availability of gas for wholesale sales during the fourth quarter of 2009.

Energy Costs

Energy Costs include Fuel for Generation and Purchased Power. These costs are dependent upon many factors which may vary by season or period. As a result, SPPC's usage and average cost per MWh of Fuel for Generation versus Purchased Power can vary significantly as the company meets the demands of the season. These factors include, but are not limited to:

- Weather;
- Plant outages;
- Total system demand;
- Resource constraints;
- Transmission constraints;
- Gas transportation constraints;
- Natural gas constraints;
- Mandated power purchases; and
- Generation efficiency.

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Energy Costs					
Fuel for Generation	$233,065	-20.8%	$294,121	3.8%	$283,342
Purchased Power	143,642	9.7%	130,977	-55.4%	293,527
Total Energy Costs	376,707	-11.4%	$425,098	-26.3%	$576,869
MWhs					
MWhs Generated (in thousands)	5,121	-8.3%	5,582	20.5%	4,633
Purchased Power (in thousands)	3,510	6.5%	3,296	-27.5%	4,547
Total MWhs	8,631	-2.8%	8,878	-3.3%	9,180
Average cost per MWh					
Average fuel cost per MWh of Generated Power	$ 45.51	-13.6%	$ 52.69	-13.8%	$ 61.16
Average cost per MWh of Purchased Power	$ 40.92	3.0%	$ 39.74	-38.4%	$ 64.55
Total average cost per MWh	$ 43.65	-8.8%	$ 47.88	-23.8%	$ 62.84

Energy costs and the average cost per MWh decreased for the year ended December 31, 2010, compared to the same period in 2009, primarily due to decreased costs associated with hedging activities partially offset by the higher natural gas costs. The decrease in total system demand for the year ended December 31, 2010 compared to the same period in 2009 is primarily due to a decrease in customer usage which may be attributable to economic conditions, conservation programs and milder winter temperatures in 2010.

- Fuel for generation decreased primarily due to a decrease in costs associated with hedging activities and a decrease in generation, partially offset by an increase in natural gas costs. MWhs generated decreased primarily due to internal generation outages. The average fuel cost per MWh of generated power was less primarily due to a decrease in costs associated with hedging activities.
- Purchased power costs and the average cost per MWh increased primarily due to an increase in volume as a result of internal generation outages.

Energy costs decreased for the year ended December 31, 2009, compared to the same period in 2008 due to lower natural gas prices, reduced capacity, tolling and transmission costs, which were partially offset by costs associated with hedging activities. Total MWhs decreased due to cooler summer temperatures, certain customers switching to DOS and a change in customer usage patterns.

- Fuel for generation increased primarily due to an increase in self generation as a result of the expansion at the Tracy Generating Station which was placed in service July 2008. The average cost per MWh for fuel for generation decreased in 2009 primarily due to lower market prices for natural gas partially offset by increased costs for hedging transactions.
- Purchase power costs and the average cost per MWh of purchased power decreased primarily due to a decrease in volume. As a result of the decrease in volume SPPC was able to fulfill a significant amount of its purchased power requirements through the purchase power contract with Newmont, as discussed above under Electric Operating Revenues. Furthermore, SPPC was able to significantly reduce capacity, tolling and transmission costs.

Gas Purchased for Resale

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Gas Purchased for Resale	$137,702	-10.4%	$153,607	-9.9%	$170,468
Gas Purchased for Resale (in thousands of Dth)	21,219	8.3%	19,588	1.7%	19,265
Average Cost per Dth	$ 6.49	-17.2%	$ 7.84	-11.4%	$ 8.85

Gas purchased for resale and average cost per Dth decreased for the year ended December 31, 2010 as compared to the same period in 2009. The decrease is primarily due to decreased hedging costs. The volume of gas purchased for resale increased in 2010 compared to 2009 primarily due to sales related to the optimization of pipeline capacity and excess availability of gas for wholesale sales.

Gas purchased for resale and average cost per Dth decreased for the year ended December 31, 2009 as compared to the same period in 2008. The decrease is primarily due to a decrease in natural gas prices partially offset by an increase in hedging cost. The volume of gas purchased for resale increased in 2009 compared to 2008 primarily due to slightly colder weather in 2009.

Deferred Energy

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Deferred energy - electric	$ 8,475	-88.5%	$73,829	5618.7%	$ 1,291
Deferred energy - gas	9,789	28.2%	7,636	-265.7%	(4,609)
Total	$18,264		$81,465		$(3,318)

Deferred energy 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 also includes the current amortization of fuel and purchased power costs previously deferred.

Deferred energy - electric for 2010, 2009 and 2008 reflect amortization of deferred energy costs of $(42.5) million, $(7.6) million and $16.3 million, respectively; and an over-collection of amount recoverable in rates of $51 million and $81.4 million in 2010 and 2009, respectively, and an under-collection of $15 million in 2008. See Note 3, *Regulatory Actions*, of the Notes to Financial Statements for further detail of deferred energy balances.

Deferred energy - gas for 2010, 2009 and 2008 reflect amortization of deferred energy of $(11.1) million, $(3.1) million and $(1) million, respectively; and an over-collection of amount recoverable in rates of $20.9 and $10.8 million in 2010 and 2009, respectively, and an under-collection of $3.6 million in 2008.

Other Operating Expenses

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Other operating expense	$149,946	-12.2%	$170,849	21.1%	$141,064
Maintenance expense	$ 32,808	4.9%	$ 31,290	1.6%	$ 30,787
Depreciation and amortization	$106,807	0.7%	$106,048	18.5%	$ 89,528

Other operating expense decreased for the year ended December 31, 2010, compared to the same period in 2009, primarily due to lower employee pension and benefit expenses, costs incurred in 2009 related to severance programs, as discussed further in Note 17, *Severance Programs*, of the Notes to Financial Statements and a reduction in bad debt expense, partially offset by increases in regulatory expenses. In addition, other operating expenses decreased as a result of costs associated with the REPR. Beginning in 2010, these amounts are reported net of their related operating expense; as such, REPR amounts no longer effect operating expense. In 2009 and 2008, REPR costs were not material and were included in operating expenses with a corresponding amount recorded to revenues and had no effect on net income.

Other operating expense increased for the year ended December 31, 2009, compared to the same period in 2008, primarily due to higher pension and other post retirement benefit expenses, costs related to the severance programs, as discussed further in Note 17, *Severance Programs*, of the Notes to Financial Statements, legal expenses, operating expenses for the Tracy Generating Station expansion placed in service in summer 2008 and chemical costs for the Valmy Generating Station. Additionally, contributing to higher expenses was higher provisions for bad debt in 2009 compared to 2008.

Maintenance expense increased for the year ended December 31, 2010, compared to the same period in 2009, mainly due to a scheduled major outage at the Valmy Generating Station, partially offset by the timing of planned maintenance and outages at the Tracy Generating Station.

Maintenance expense increased for the year ended December 31, 2009, compared to the same period in 2008, mainly due to the addition of the Tracy Generating Station expansion that became operational in summer of 2008, partially offset by outages at the Valmy Generating Station for boiler repairs in 2008 and lower maintenance cost for Ft. Churchill in 2009.

Depreciation and amortization increased slightly for the year ended December 31, 2010, compared to the same period in 2009, primarily due to regular system growth.

Depreciation and amortization increased for the year ended December 31, 2009 compared to the same period in 2008, primarily as a result of increases in plant-in-service primarily due to the completion of the Tracy Generating Station in July 2008.

Interest Expense

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Interest Expense (net of AFUDC-debt: $1,912, $3,044 and $9,464)	$68,514	-1.3%	$69,413	-4.5%	$72,712

Interest expense decreased for the year ended December 31, 2010, compared to the same period in 2009 primarily due to lower interest on the revolving credit facility and variable rate debt, partially offset by lower AFUDC.

Interest expense decreased for the year ended December 31, 2009 compared to the same period in 2008 primarily due to lower interest rates on variable rate debt, interest savings related to repurchased debt, and the redemption of $99 million Series A General and Refunding Mortgage Bonds in June 2008. These amounts were partially offset by the issuance of $250 million Series Q General and Refunding Mortgage Notes in September 2008, the addition of $150 million to its 6.0% Series M General and Refunding Mortgage Notes in August 2009 and a decrease in AFUDC-debt due to the completion of the Tracy Generating Station in July of 2008. See Note 6, *Long-Term Debt*, of the Notes to Financial Statements for additional information regarding long-term debt.

Other Income and (Expenses)

	2010		2009		2008
	Amount	Change from Prior Year	Amount	Change from Prior Year	Amount
Interest income (expense) on regulatory items	$ (9,348)	62.8%	$ (5,743)	175.2%	$ (2,087)
AFUDC-equity	$ 2,883	-11.3%	$ 3,249	-74.1%	$12,524
Other income	$16,748	26.2%	$13,276	3.6%	$12,819
Other expense	$ (9,985)	30.6%	$ (7,648)	-8.1%	$ (8,318)

Interest expense on regulatory items increased for the year ended December 31, 2010, compared to the same period in 2009, due to higher over-collected deferred energy balances in 2010.

Interest expense on regulatory items increased for the year ended December 31, 2009, compared to the same period in 2008, due to higher over-collected deferred energy balances in 2009.

AFUDC-equity was lower for the year ended December 31, 2010 compared to the same period in 2009 primarily due to the completion of various transmission projects, which resulted in a decrease in the CWIP balance in 2010.

AFUDC-equity was lower for the year ended December 31, 2009 compared to the same period in 2008 primarily due to the completion of the Tracy Generating Station in July of 2008, which resulted in a decrease in the CWIP balance.

Other income increased for the year ended December 31, 2010, compared to the same period in 2009, primarily due to the gain on sale for the Independence Lake property in 2010, as further discussed in Note 16, *Assets Held for Sale* of the Notes to Financial Statements, adjustments resulting from SPPC's 2010 electric GRC, and interest income on investments in 2010, partially offset by a gain recognized in 2009 on the sale of the Farad hydro units and interest received for tax refunds in 2009.

Other income increased for the year ended December 31, 2009 compared to the same period in 2008 primarily due to gains on the disposition of property in 2009 and interest received for tax refunds partially offset by income earned in 2008 related to the reinstatement of previously disallowed costs associated with Piñon Pine and the settlement with Calpine as discussed in Note 3, *Regulatory Actions* and Note 13, *Commitments and Contingencies* of the Notes to Financial Statements.

Other expense increased for the year ended December 31, 2010, compared to the same period in 2009, due to an increase in donations related to Independence Lake and adjustments resulting from SPPC's 2010 electric GRC. Partially offsetting the increase was a disallowance, in 2009, relating to contract pricing for energy.

Other expense decreased for the year ended December 31, 2009 compared to the same period in 2008 due to lower advertising costs in 2009 and adjustments resulting from SPPC's 2007 GRC effective in 2008. Partially offsetting the decrease was a disallowance relating to contract pricing for energy.

ANALYSIS OF CASH FLOWS

SPPC's cash flows increased during 2010 compared to 2009 due to a reduction in cash used by investing activities offset by a decrease in cash from operating activities and a decrease in cash from financing activities.

Cash From Operating Activities. The decrease in cash from operating activities is primarily due to a reduction in BTER and DEAA rates charged to customers, and an increase in spending on energy conservation programs. The decrease in cash was partially offset by decreased spending on fuel for purchased power costs and a decrease in funding for pension plans compared to 2009.

Cash Used By Investing Activities. Cash used by investing activities decreased mainly due to the slowdown in construction for infrastructure, and proceeds from the sale of property.

Cash From Financing Activities. Cash from financing activities decreased primarily due to the redemption of SPPC's 6.25% General and Refunding Mortgage Notes, Series H due 2012 in an aggregate principal amount of $100 million and a decrease in capital contributions from NVE. This decrease was partially offset by lower dividend payments to NVE.

LIQUIDITY AND CAPITAL RESOURCES

Overall Liquidity

SPPC'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, capital expenditures and the payment of interest on SPPC's outstanding indebtedness. Operating cash flows can be significantly influenced by factors such as weather, regulatory outcome and economic conditions. Available liquidity as of December 31, 2010 was as follows (in millions):

Available Liquidity as of December 31, 2010

	SPPC
Cash and Cash Equivalents	$ 9.6
Balance available on Revolving Credit Facility[(1)]	219.3
Less Reduction for Hedging Transactions[(2)]	(13.8)
	$215.1

(1) As of February 23, 2011, SPPC had approximately $230.9 million available under its revolving credit facility which includes reductions for hedging transactions and letters of credits, as discussed below under *Financing Transactions*.

(2) Reduction for hedging transactions reflects balance as of November 30, 2010.

SPPC attempts to maintain its cash and cash equivalents in highly liquid investments, such as U.S. Treasury Bills and bank deposits. In addition to cash on hand, SPPC may use its revolving credit facility in order to meet its liquidity needs. Alternatively, depending on the usage of the revolving credit facility, SPPC may issue debt, subject to certain restrictions as discussed in *Factors Affecting Liquidity*, Ability to Issue Debt, below.

SPPC has no significant debt maturities in either 2011 or 2012. As of February 23, 2011, SPPC has no borrowings on its revolving credit facility, not including letters of credit.

SPPC anticipates that it will be able to meet short-term operating costs, such as fuel and purchased power costs, with internally generated funds, including the recovery of deferred energy and the use of its revolving credit facility. Furthermore, in order to fund long-term capital requirements and maturing debt obligations, SPPC will use a combination of internally generated funds, its revolving credit facility, the issuance of long-term debt and/or capital contributions from NVE. However, if energy costs rise at a rapid rate and SPPC does not recover the cost of fuel and purchased power in a timely manner, if operating costs are not recovered in a timely manner or SPPC were to experience a credit rating downgrade resulting in the posting of collateral as discussed below under *Gas Supplier Matters* and *Financial Gas Hedges,* the amount of liquidity available to SPPC could be significantly less. In order to maintain sufficient liquidity, SPPC may be required to further delay capital expenditures, refinance debt or obtain funding through an equity issuance by NVE.

The ability to issue debt, as discussed later, is subject to certain covenant calculations which include consolidated net income of NVE and the Utilities. As a result of these covenant calculations and the seasonality of the Utilities' business, the ability to issue debt can vary from quarter to quarter, and the Utilities may not be able to fully utilize the availability on their revolving credit facilities.

In 2010, SPPC's credit ratings on its senior secured debt remained at investment grade (see *Credit Ratings* below). In 2010, SPPC did not experience any limitations in the credit markets, nor do we expect any significant limitations in 2011. However, disruptions in the banking and capital markets not specifically related to SPPC may affect its ability to access funding sources or cause an increase in the interest rates paid on newly issued debt.

In 2010, SPPC paid dividends to NVE of $54 million and at December 31, 2010 had $54 million in dividends payable which was subsequently paid in January 2011.

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, recently completed Financing Transactions and Factors Affecting Liquidity, including our ability to obtain debt on favorable terms.

Capital Structure

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

	2010		2009	
	Amount	Percent of Total Capitalization	Amount	Percent of Total Capitalization
Current Maturities of Long-Term Debt	$ -	0.0%	$ 15,000	0.6%
Long-Term Debt	1,195,775	55.1%	1,282,225	55.6%
Shareholder's Equity	973,420	44.9%	1,009,258	43.8%
Total	$2,169,195	100%	$2,306,483	100%

Capital Requirements

Construction Expenditures

SPPC's cash requirement for construction expenditures for 2011 is projected to be $146.3 million. SPPC's cash requirement for construction expenditures for 2011 through 2015 is projected to be

$809.2 million. Cash used by investing activities for the years ended 2010, 2009 and 2008 were approximately $122.6 million, $185.7 million and $207.8 million, respectively. To fund future 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 NVE.

Contractual Obligations

The table below provides SPPC's consolidated contractual obligations, as of December 31, 2010, 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. Certain contracts contain variable factors which required SPPC to estimate the obligation depending on the final variable amount. Actual amounts could differ. The table does not include estimated construction expenditures described above, except for major capital projects for which SPPC has executed contracts by December 31, 2010. Additionally, at December 31, 2010, SPPC recorded an uncertain tax liability of $10.2 million as required by the accounting guidance for Uncertainty in Income Taxes Topic of the FASC, all of which is classified as non-current. SPPC is unable to make a reasonably reliable estimate of the period of cash payments to relevant tax authorities; consequently, none of the uncertain tax liability is included in the contractual obligations table below (dollars in thousands):

	Payment Due by Period						
	2011	2012	2013	2014	2015	Thereafter	Total
Long-Term Debt Maturities	$ -	$ -	$265,000	$ -	$ -	$ 916,417	$1,181,417
Long-Term Debt Interest Payments	59,188	59,157	54,615	45,532	45,532	404,593	668,617
Purchased Power	168,138	168,226	110,741	109,734	117,665	810,102	1,484,606
Coal and Natural Gas	157,992	58,817	17,018	18,183	15,543	-	267,553
Transportation(1)	85,319	77,861	65,602	57,530	44,050	213,318	543,680
Long-Term Service Agreements(2)	4,562	4,770	4,478	4,519	4,582	21,842	44,753
Capital Projects(3)	8,130	67,923	153	-	-	-	76,206
Operating Leases	7,911	6,275	5,134	4,149	2,635	34,813	60,917
Total Contractual Cash Obligations	$491,240	$443,029	$522,741	$239,647	$230,007	$2,401,085	$4,327,749

(1) Includes the TUA with GBT which is contingent upon final construction costs and reaching commercial operation, which is expected in late 2012.

(2) Amounts based on estimated usage.

(3) Capital projects include NV Energize. Additionally, SPPC, as a joint owner, has obligations regarding the construction of ON Line.

Pension and Other Postretirement Benefit Plan Matters

NVE has a qualified pension plan and other postretirement benefits plan which cover substantially all employees of NVE, NPC and SPPC. The annual net benefit cost for the plans is expected to decrease in 2011 by approximately $7.3 million compared to the 2010 cost of $36.2 million. As of December 31, 2010, the measurement date, the plan was under funded under the provisions of the Compensation Retirement Benefits Topic of the FASC. Refer to Note 11, *Retirement Plan and Post-Retirement Benefits*, of the Notes to the Consolidated Financial Statements. During 2010, NVE funded a total of $40 million to the trusts established for these plans. At the present time it is not expected that additional funding will be required in 2011 to meet the minimum funding level requirements defined by the Pension Protection Act of 2006. However, NVE and the Utilities have included in their 2011 assumptions funding levels similar to the 2010 funding. The amounts to be contributed in 2011 may change subject to market conditions.

Financing Transactions

Redemption of General and Refunding Mortgage Notes, Series H

In December 2010, SPPC redeemed all of its 6.25% General & Refunding Mortgage Notes, Series H, due 2012, in an aggregate principal amount of $100 million. The notes were redeemed in December 2010 at a purchase price of $1,069.61 for each $1,000 principal amount of the Notes, plus accrued interest. The redemption was predominantly funded with available cash on hand, and the remainder funded with a draw on SPPC's revolving credit facility.

$250 Million Revolving Credit Facility

In April 2010, SPPC terminated its $332 million secured revolving credit facility which would have expired in November 2010 and replaced it with a $250 million secured revolving credit facility, maturing in April 2013. The fees on the $250 million revolving credit facility for the unused portion and on the amounts borrowed have increased from the prior facility reflecting current market conditions. The Administrative Agent for the facility is Bank of America, N.A. The rate for outstanding loans under the revolving credit facility will be at either an applicable base rate (defined as the highest of the Prime Rate, the Federal Funds Rate plus ½ of 1.0% and the LIBOR Base Rate plus 1.0%) plus a margin, or a LIBOR rate plus a margin. The margin varies based upon NPC's credit rating by S&P and Moody's. Currently, SPPC's applicable base rate margin is 1.25% and the LIBOR rate margin is 2.25%. The rate for outstanding letters of credit will be at the LIBOR rate margin plus a fee for the issuing bank.

The $250 million revolving credit facility contains a provision which reduces the availability under the credit facility by the negative mark-to-market exposure for hedging transactions with credit facility lenders or their energy trading affiliates. The reduction in availability limits the amount that SPPC can borrow or use for letters of credit and would require that SPPC prepay any amount in excess of that limitation. The amount of the reduction is calculated by SPPC on a monthly basis, and after calculating such reduction, the SPPC Credit Agreement provides that reduction in the availability under the revolving credit facility to SPPC shall not exceed 50% of the total commitments then in effect under the revolving credit facility.

The SPPC Credit Agreement contains one financial maintenance covenant that requires SPPC 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. In the event that SPPC did not meet the financial maintenance covenant or there is an event of default, the SPPC Credit Agreement would restrict dividends to NVE. Moreover, so long as SPPC's senior secured debt remains rated investment grade by S&P and Moody's (in each case, with a stable or better outlook), a representation concerning no material adverse change in SPPC's business, assets, property or financial condition would not be a condition to the availability of credit under the facility. In the event that SPPC's senior secured debt rating were rated below investment grade by either S&P or Moody's, or investment grade by either S&P or Moody's but with a negative outlook, a representation concerning no material adverse change in SPPC's business, assets, property or financial condition would be a condition to borrowing under the revolving credit facility.

Factors Affecting Liquidity

Ability to Issue Debt

SPPC's ability to issue debt is impacted by certain factors such as financing authority from the PUCN, financial covenants in its financing agreements and its revolving credit facility agreement, and the terms of certain NVE debt. As of December 31, 2010, the most restrictive of the factors below is the PUCN authority. Based on this restriction, SPPC may issue up to $350 million of long term debt securities, and maintain a credit facility of up to $600 million. However, depending on NVE's or NPC's issuance of long-term debt or the use of the Utilities' revolving credit facilities, the PUCN authority may not remain the most restrictive factor. The factors affecting SPPC's ability to issue debt are further detailed below:

a. Financing authority from the PUCN - As of December 31, 2010, SPPC has financing authority from the PUCN for the period ending December 31, 2012, consisting of authority (1) to issue additional long term debt securities of up to $350 million; (2) to refinance approximately $348 million of long-term debt securities; and (3) ongoing authority to maintain a revolving credit facility of up to $600 million,

b. Financial covenants within SPPC's financing agreements - Under SPPC's $250 million revolving credit facility, the Utility must 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. Based on December 31, 2010 financial statements, SPPC was in compliance with this covenant and could incur up to $857 million of additional indebtedness.

All other financial covenants contained in SPPC's financing agreements are suspended, as SPPC's senior secured debt is rated investment grade. However, if SPPC's senior secured debt ratings fall below investment grade by either Moody's or S&P, SPPC would again be subject to the limitations under these additional covenants; and

c. Financial covenants within NVE's financing agreements - As discussed in NVE's *Ability to Issue Debt*, SPPC is also subject to NVE's cap on additional consolidated indebtedness of $1.9 billion.

Ability to Issue General and Refunding Mortgage Securities

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 SPPC's General and Refunding Mortgage Indenture (''Indenture'').

The Indenture creates a lien on substantially all of SPPC's properties in Nevada and California. As of December 31, 2010, $1.5 billion of SPPC's General and Refunding Mortgage Securities were outstanding. SPPC had the capacity to issue $860.1 million of additional General and Refunding Mortgage Securities as of December 31, 2010. However, as a result of the sale of the California assets as discussed in Note 16, *Assets Held for Sale*, in the Notes to the Financial Statements, SPPC's capacity to issue General and Refunding Mortgage Securities as of January 1, 2011 was reduced to $725.1 million. 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.

Property additions include plant in service and specific assets in CWIP. The amount of bond capacity listed above does not include eligible property in CWIP.

SPPC also has the ability to release property from the lien of the mortgage indenture on the basis of net property additions, cash and/or retired bonds. To the extent SPPC releases property from the lien of SPPC's Indenture, it will reduce the amount of securities issuable under the Indenture.

Credit Ratings

The liquidity of SPPC, the cost and availability of borrowing by SPPC under its credit facility, the potential exposure of SPPC to collateral calls under various contracts and the ability of SPPC to acquire fuel and purchased power on favorable terms are all directly affected by the credit ratings for SPPC's debt. SPPC's senior secured debt is rated investment grade by three NRSROs: Fitch, Moody's and S&P. In May 2010, Fitch upgraded the rating for SPPC's senior secured debt to BBB from BBB- and revised the rating outlook from positive to stable. As of December 31, 2010, the ratings are as follows:

		Rating Agency		
		Fitch	Moody's	S&P
SPPC	Sr. Secured Debt	BBB*	Baa3*	BBB*

* Investment grade

Fitch's, Moody's and S&P's rating outlook for SPPC is Stable.

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. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be evaluated in the context of the applicable methodology, independently of all other ratings. The rating agencies provide ratings at the request of the company being rated and charge the company fees for their services.

Energy Supplier Matters

With respect to SPPC's contracts for purchased power, SPPC purchases and sells electricity with counterparties under the WSPP agreement, an industry standard contract that SPPC uses as a member of the WSPP. The WSPP contract is posted on the WSPP website.

Under these contracts, a material adverse change, which includes a credit rating downgrade, in SPPC may allow the counterparty to request adequate financial assurance, which, if not provided within three business days, could cause a default. Most contracts and confirmations for purchased power have been modified or separate agreements have been made to either shorten the normal payment due date or require payment in advance of delivery in response to requests for financial assurance. 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. Under the net mark-to-market value as of December 31, 2010 for all suppliers continuing to provide power under a WSPP agreement no amounts would be due to or from SPPC. These contracts qualify for the normal purchases scope exception as defined by the Derivatives and Hedging Topic of the FASC, and as such, are not required to be mark-to-market on the balance sheet. Refer to Note 6, *Derivatives and Hedging Activities*, of the Notes to Financial Statements, for further discussion.

Gas Supplier Matters

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 change, which primarily means a credit rating downgrade below investment grade. Forward physical gas supplies are purchased under index based pricing terms and as such do not carry forward mark-to-market exposure. 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, no 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 Gas Hedges

SPPC enters into certain hedging contracts with various counterparties to manage the gas price risk inherent in purchased power and fuel contracts. As discussed under SPPC's Financing Transactions, the availability under SPPC's revolving credit facility is reduced by the amount of net negative mark-to-market positions on hedging contracts with counterparties who are lenders to the revolving credit facility, provided that the reduction in availability under the revolving credit facility shall at no time exceed 50% of the total commitments then in effect under the revolving credit facility. The calculation of SPPC's negative mark-to-market exposure as of November 30, 2010 was approximately $13.8 million, which amount was in effect for borrowings during the month of December 2010. Currently, SPPC only has hedging contracts with counterparties who are also lenders on the revolving credit facility; however, future contracts entered into with non-lenders may require SPPC to post cash collateral in the event of a credit rating downgrade. Finally, in October 2009, SPPC suspended its hedging program, as such, expects its exposure to negative mark-to-market positions to decline.

Cross Default Provisions

None of the financing agreements of SPPC contains a cross-default provision that would result in an event of default by SPPC upon an event of default by NVE or NPC under any of its financing agreements. In addition, 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

As of December 31, 2010, NVE, 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. The tables below do not include the interest rate swap entered into in 2009 and discussed further in Note 9, *Derivatives and Hedging Activities*, of the Notes to Financial Statements, as the amount is considered immaterial. 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 as of December 31 (dollars in thousands):

	2010 Expected Maturities							
	2011	2012	2013	2014	2015	Thereafter	Total	Fair Value
Long-Term Debt								
NVE								
Fixed Rate	$ -	$ -	$ -	$ -	$ -	$ 506,500	$ 506,500	$ 514,192
Average Interest Rate	-	-	-	-	-	6.44%	6.44%	
NPC								
Fixed Rate	$350,000	$130,000	$ -	$125,000	$250,000	$2,505,000	$3,360,000	$3,747,846
Average Interest Rate	8.25%	6.50%	-	7.38%	5.88%	6.52%	6.69%	
Variable Rate	$ -	$ -	$ -	$ -	$ -	$ 173,775	$ 173,775	$ 173,775
Average Interest Rate	-	-	-	-	-	0 .79%	0 .79%	
SPPC								
Fixed Rate	$ -	$ -	$250,000	$ -	$ -	$ 701,742	$ 951,742	$1,059,041
Average Interest Rate	-	-	5.45%	-	-	6.27%	6.05%	
Variable Rate	$ -	$ -	$ 15,000	$ -	$ -	$ 214,675	$ 229,675	$ 229,675
Average Interest Rate	-	-	2.51%	-	-	0 .75%	0 .86%	
TOTAL DEBT	$350,000	$130,000	$265,000	$125,000	$250,000	$4,101,692	$5,221,692	$5,724,529

	2009 Expected Maturities							
	2010	2011	2012	2013	2014	Thereafter	Total	Fair Value
Long-Term Debt								
NVE								
Fixed Rate	$ -	$ -	$ 63,670	$ -	$230,039	$ 191,500	$ 485,209	$ 490,533
Average Interest Rate	-	-	7.80%	-	8.63%	6.75%	7.78%	
NPC								
Fixed Rate	$ -	$364,000	$130,000	$ -	$125,000	$2,717,050	$3,336,050	$3,564,421
Average Interest Rate	-	8.14%	6.50%	-	7.38%	6.50%	6.72%	
Variable Rate	$110,000	$ -	$ -	$ -	$ -	$ 173,775	$ 283,775	$ 283,775
Average Interest Rate	0.99%	-	-	-	-	0 .98%	0 .99%	
SPPC								
Fixed Rate	$ -	$ -	$100,000	$250,000	$ -	$ 701,742	$1,051,742	$1,112,275
Average Interest Rate	-	-	6.25%	5.45%	-	6.27%	6.07%	
Variable Rate	$ 15,000	$ -	$ -	$ -	$ -	$ 214,675	$ 229,675	$ 229,675
Average Interest Rate	0.99%	-	-	-	-	1.00%	1.00%	
TOTAL DEBT .	$125,000	$364,000	$293,670	$250,000	$355,039	$3,998,742	$5,386,451	$5,680,679

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 1, Business, for a discussion of the Utilities' purchased power procurement strategies.

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 $60.1 million as of December 31, 2010, which compares to balances of $73.2 million at December 31, 2009. The decrease from December 31, 2009 is primarily due to the decrease in prices of natural gas and power during 2010.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
NV Energy, Inc.
Las Vegas, Nevada

We have audited the accompanying consolidated balance sheets of NV Energy, Inc. and subsidiaries (the ''Company'') as of December 31, 2010 and 2009, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 NV Energy, Inc. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP
Las Vegas, Nevada
February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Nevada Power Company and subsidiaries (the ''Company'') as of December 31, 2010 and 2009, and the related consolidated statements of income, comprehensive income, shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Las Vegas, Nevada
February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Sierra Pacific Power Company and subsidiaries (the ''Company'') as of December 31, 2010 and 2009, and the related consolidated statements of income, comprehensive income, shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Las Vegas, Nevada
February 25, 2011

NV ENERGY, INC.
CONSOLIDATED INCOME STATEMENTS
(Dollars in Thousands, Except Per Share Amounts)

	Year Ended December 31,		
	2010	2009	2008
OPERATING REVENUES	$ 3,280,222	$ 3,585,798	$ 3,528,113
OPERATING EXPENSES:			
Fuel for power generation	821,484	881,768	1,039,267
Purchased power	648,881	758,736	974,343
Gas purchased for resale	137,702	153,607	170,468
Deferred energy	113,107	289,076	(10,265)
Other operating expenses	414,241	453,413	394,019
Maintenance	104,567	102,309	94,069
Depreciation and amortization	333,059	321,921	260,608
Taxes other than income	62,746	60,885	53,525
Total Operating Expenses	2,635,787	3,021,715	2,976,034
OPERATING INCOME	644,435	564,083	552,079
OTHER INCOME (EXPENSE):			
Interest expense (net of AFUDC-debt: $23,355, $20,229 and $29,527)	(333,010)	(334,314)	(300,857)
Interest income (expense) on regulatory items	(12,517)	(2,280)	5,255
AFUDC-equity	28,112	24,274	38,441
Other income	36,841	33,122	34,278
Other expense	(23,113)	(26,498)	(24,955)
Total Other Income (Expense)	(303,687)	(305,696)	(247,838)
Income Before Income Tax Expense	340,748	258,387	304,241
Income tax expense (Note 10)	113,764	75,451	95,354
NET INCOME	$ 226,984	$ 182,936	$ 208,887
Amount per share basic and diluted - (Note 15)			
Net income per share - basic	$ 0.97	$ 0.78	$ 0.89
Net income per share - diluted	$ 0.96	$ 0.78	$ 0.89
Weighted Average Shares of Common Stock Outstanding - basic	235,048,347	234,542,292	234,031,750
Weighted Average Shares of Common Stock Outstanding - diluted	236,294,812	235,180,688	234,585,004
Dividends Declared Per Share of Common Stock	$ 0.45	$ 0.41	$ 0.34

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

NV ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

(Dollars in Thousands)

	December 31, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 86,189	$ 62,706
Accounts receivable less allowance for uncollectible accounts: 2010 - $28,684; 2009 - $32,341	354,010	400,911
Materials, supplies and fuel, at average cost	114,520	124,040
Risk management assets (Note 9)	4,007	27,558
Income taxes receivable	82	-
Deferred income taxes (Note 10)	130,800	87,562
Other current assets	42,330	44,298
Total Current Assets	731,938	747,075
Utility Property:		
Plant in service	11,068,518	10,833,622
Construction work-in-progress	908,579	716,128
Total (Note 1)	11,977,097	11,549,750
Less accumulated provision for depreciation	3,047,438	2,884,199
Total Utility Property, Net	8,929,659	8,665,551
Investments and other property, net (Note 4)	61,613	51,169
Deferred Charges and Other Assets:		
Deferred energy (Note 3)	117,623	138,963
Regulatory assets (Note 3)	1,237,159	1,218,778
Regulatory asset for pension plans (Note 3)	269,472	264,892
Risk management assets (Note 9)	-	6,732
Other deferred charges and assets	166,882	173,145
Total Deferred Charges and Other Assets	1,791,136	1,802,510
Assets Held for Sale (Note 16)	155,322	147,158
TOTAL ASSETS	$11,669,668	$11,413,463

(Continued)

NV ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

(Dollars in Thousands)

	December 31, 2010	December 31, 2009
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of long-term debt (Note 6)	$ 355,929	$ 134,474
Accounts payable	346,409	352,000
Accrued expenses	133,851	134,328
Risk management liabilities (Note 9)	33,229	66,871
Deferred energy (Note 3)	315,839	191,405
Other current liabilities	70,638	67,301
Total Current Liabilities	1,255,895	946,379
Long-term debt (Note 6)	4,924,109	5,303,357
Commitments and Contingencies (Note 13)		
Deferred Credits and Other Liabilities:		
Deferred income taxes (Note 10)	1,246,410	1,072,780
Deferred investment tax credit	19,204	22,541
Accrued retirement benefits	148,841	149,925
Risk management liabilities (Note 9)	-	2,233
Regulatory liabilities (Note 3)	428,114	386,019
Other deferred credits and liabilities	265,571	280,560
Total Deferred Credits and Other Liabilities	2,108,140	1,914,058
Liabilities Held for Sale (Note 16)	30,706	25,747
Shareholders' Equity:		
Common stock ($1.00 par value; 350 million shares authorized; 235,322,553 and 234,834,169 issued and outstanding for 2010 and 2009, respectively)	235,323	234,834
Other paid-in capital	2,705,954	2,700,329
Retained earnings	416,432	295,247
Accumulated other comprehensive loss	(6,891)	(6,488)
Total Shareholders' Equity	3,350,818	3,223,922
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$11,669,668	$11,413,463

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

(Concluded)

NV ENERGY, INC
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	For the Year Ended December 31,		
	2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 226,984	$ 182,936	$ 208,887
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	333,059	321,921	260,608
Deferred taxes and deferred investment tax credit	129,231	111,219	52,060
AFUDC-equity	(28,112)	(24,274)	(38,441)
Deferred energy	147,497	306,406	2,717
Gain on sale of asset	(7,575)	-	-
Amortization of other regulatory assets	110,654	101,641	7,453
Deferred rate increase	(8,343)	(95,890)	-
Other, net	(20,666)	(7,755)	93,029
Changes in certain assets and liabilities:			
Accounts receivable	52,238	12,733	39,776
Materials, supplies and fuel	9,167	465	(7,908)
Other current assets	1,969	8,335	(6,724)
Accounts payable	28,070	(31,888)	(12,028)
Accrued retirement benefits	(18,476)	(20,080)	(79,242)
Other current liabilities	2,945	(17,287)	40,747
Risk management assets and liabilities	12,267	5,058	(4,924)
Other deferred assets	(6,111)	(13,831)	(51,874)
Other regulatory assets	(77,893)	(69,937)	(67,460)
Other deferred liabilities	(453)	(18,251)	22,238
Net Cash from Operating Activities	886,452	751,521	458,914
CASH FLOWS USED BY INVESTING ACTIVITIES:			
Additions to utility plant (excluding AFUDC-equity)	(629,496)	(843,132)	(1,535,503)
Proceeds from sale of asset	18,225	-	-
Customer advances for construction	(11,142)	(8,369)	(11,981)
Contributions in aid of construction	63,330	76,940	62,521
Investments and other property - net	(8,974)	(26,061)	4,301
Net Cash used by Investing Activities	(568,057)	(800,622)	(1,480,662)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of long-term debt	985,419	1,418,872	2,135,151
Retirement of long-term debt	(1,180,646)	(1,271,350)	(1,114,226)
Sale of Common Stock	6,114	6,051	5,756
Dividends paid	(105,799)	(96,125)	(79,714)
Net Cash from/(used by) Financing Activities	(294,912)	57,448	946,967
Net Increase in Cash and Cash Equivalents	23,483	8,347	(74,781)
Beginning Balance in Cash and Cash Equivalents	62,706	54,359	129,140
Ending Balance in Cash and Cash Equivalents	$ 86,189	$ 62,706	$ 54,359
Supplemental Disclosures of Cash Flow Information:			
Cash paid during period for:			
Interest	$ 336,668	$ 325,508	$ 284,044
Income taxes	$ 754	$ (13,186)	$ 10,677
Significant non-cash transactions:			
Accrued construction expenses as of December 31,	$ 86,127	$ 127,786	$ 143,982
Capital lease obligations incurred	$ 15,336	$ -	$ -
Transfer of assets to accounts receivable	$ 16,830	$ -	$ -

The accompanying notes are an integral part of the financial statements

NV ENERGY, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in Thousands)

	Year Ended December 31,		
	2010	2009	2008
NET INCOME	$226,984	$182,936	$208,887
OTHER COMPREHENSIVE INCOME (LOSS)			
Change in compensation retirement benefits liability and amortization (Net of taxes $217, $72 and $284 in 2010, 2009 and 2008, respectively)	$ (403)	$ (128)	$ (492)
OTHER COMPREHENSIVE LOSS	$ (403)	$ (128)	$ (492)
COMPREHENSIVE INCOME	$226,581	$182,808	$208,395

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

NV ENERGY, INC.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Dollars in Thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
December 31, 2007	233,738,905	$233,739	$2,684,845	$ 83,859	$(5,868)	$2,996,575
Net Income		-	-	208,887	-	208,887
Dividend Reinvestment and Employee Benefits	577,924	578	9,672	-	-	10,250
Common Stock issuance costs		-	(90)	-	-	(90)
Tax benefit from stock options exercised		-	365		-	365
Compensation retirement benefits (net of taxes ($2,514))		-		(4,670)	-	(4,670)
Change in compensation retirement benefits liability and amortization (net of taxes $284)		-			(492)	(492)
Dividends Declared		-	-	(79,640)	-	(79,640)
December 31, 2008	234,316,829	234,317	2,694,792	208,436	(6,360)	3,131,185
Net Income				182,936		182,936
Dividend Reinvestment and Employee Benefits	517,340	517	5,530			6,047
Tax benefit from stock options exercised			7			7
Change in compensation retirement benefits liability and amortization (net of taxes $72)					(128)	(128)
Dividends Declared				(96,125)		(96,125)
December 31, 2009	234,834,169	234,834	2,700,329	295,247	(6,488)	3,223,922
Net Income				226,984		226,984
Dividend Reinvestment and Employee Benefits	488,384	489	5,620			6,109
Common Stock issuance costs			(27)			(27)
Tax benefit from stock options exercised			32			32
Change in compensation retirement benefits liability and amortization (net of taxes $217)					(403)	(403)
Dividends Declared				(105,799)		(105,799)
December 31, 2010	235,322,553	$235,323	$2,705,954	$ 416,432	$(6,891)	$3,350,818

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

NEVADA POWER COMPANY

CONSOLIDATED INCOME STATEMENTS

(Dollars in Thousands)

	Year Ended December 31,		
	2010	**2009**	**2008**
OPERATING REVENUES	$2,252,377	$2,423,377	$2,315,427
OPERATING EXPENSES:			
Fuel for power generation	588,419	587,647	755,925
Purchased power	505,239	627,759	680,816
Deferred energy	94,843	207,611	(6,947)
Other operating expenses	260,535	279,865	249,236
Maintenance	71,759	71,019	63,282
Depreciation and amortization	226,252	215,873	171,080
Taxes other than income	37,918	37,241	32,069
Total Operating Expenses	1,784,965	2,027,015	1,945,461
OPERATING INCOME	467,412	396,362	369,966
OTHER INCOME (EXPENSE):			
Interest expense (net of AFUDC - debt: $21,443, $17,184 and $20,063)	(214,367)	(226,252)	(186,822)
Interest income (expense) on regulatory items	(3,169)	3,463	7,342
AFUDC - equity	25,229	21,025	25,917
Other income	15,541	19,658	16,631
Other expense	(12,946)	(18,320)	(10,221)
Total Other Income (Expense)	(189,712)	(200,426)	(147,153)
Income Before Income Tax Expense	277,700	195,936	222,813
Income tax expense (Note 10)	91,757	61,652	71,382
NET INCOME	$ 185,943	$ 134,284	$ 151,431

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

NEVADA POWER COMPANY
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

	December 31, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 60,077	$ 42,609
Accounts receivable less allowance for uncollectible accounts: 2010 - $26,428; 2009 - $29,375	224,704	254,027
Materials, supplies and fuel, at average cost	66,459	69,176
Risk management assets (Note 9)	3,476	21,902
Intercompany income taxes receivable	-	10,356
Deferred income taxes (Note 10)	76,282	58,425
Other current assets	29,680	27,855
Total Current Assets	460,678	484,350
Utility Property:		
Plant in service	7,552,097	7,414,432
Construction work-in-progress	825,079	627,026
Total (Note 1)	8,377,176	8,041,458
Less accumulated provision for depreciation	1,828,366	1,727,710
Total Utility Property, Net	6,548,810	6,313,748
Investments and other property, net (Note 4)	55,305	41,167
Deferred Charges and Other Assets:		
Deferred energy (Note 3)	117,623	138,963
Regulatory assets (Note 3)	871,982	856,769
Regulatory asset for pension plans (Note 3)	133,410	129,709
Risk management assets (Note 9)	-	5,590
Other deferred charges and assets	114,016	126,075
Total Deferred Charges and Other Assets	1,237,031	1,257,106
TOTAL ASSETS	$8,301,824	$8,096,371

(Continued)

NEVADA POWER COMPANY
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

	December 31, 2010	December 31, 2009
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities:		
Current maturities of long-term debt (Note 6)	$ 355,929	$ 119,474
Accounts payable	232,279	249,962
Accounts payable, affiliated companies	29,334	32,414
Accrued expenses	89,638	86,983
Risk management liabilities (Note 9)	22,764	39,122
Deferred energy (Note 3)	171,349	74,129
Other current liabilities	54,607	52,306
Total Current Liabilities	955,900	654,390
Long-term debt (Note 6)	3,221,833	3,535,440
Commitments and Contingencies (Note 13)		
Deferred Credits and Other Liabilities:		
Deferred income taxes (Note 10)	908,094	794,890
Deferred investment tax credit	7,255	8,698
Accrued retirement benefits	31,907	39,678
Risk management liabilities (Note 9)	-	1,165
Regulatory liabilities (Note 3)	225,983	210,287
Other deferred credits and liabilities	189,220	201,784
Total Deferred Credits and Other Liabilities	1,362,459	1,256,502
Shareholder's Equity:		
Common stock ($1.00 par value, 1,000 shares authorized, issued and outstanding for 2010 and 2009)	1	1
Other paid-in capital	2,254,219	2,254,189
Retained earnings	511,288	399,345
Accumulated other comprehensive loss	(3,876)	(3,496)
Total Shareholder's Equity	2,761,632	2,650,039
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$8,301,824	$8,096,371

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

(Concluded)

NEVADA POWER COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	For the Year Ended December 31,		
	2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 185,943	$ 134,284	$ 151,431
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	226,252	215,873	171,080
Deferred taxes and deferred investment tax credit	92,859	96,831	45,039
AFUDC - equity	(25,229)	(21,025)	(25,917)
Deferred energy	116,230	216,629	4,211
Amortization of other regulatory assets	74,625	61,758	24,459
Deferred rate increase	(8,343)	(95,890)	-
Other, net	(16,153)	(159)	48,750
Changes in certain assets and liabilities:			
Accounts receivable	39,679	(5,309)	35,863
Materials, supplies and fuel	3,115	4,928	(5,432)
Other current assets	(1,824)	6,802	(6,305)
Accounts payable	13,905	(10,694)	(47,424)
Accrued retirement benefits	(17,792)	(18,721)	(32,413)
Other current liabilities	4,959	(13,544)	38,598
Risk management assets and liabilities	9,565	3,319	(3,622)
Other deferred assets	(2,598)	(10,336)	(51,172)
Other regulatory assets	(50,937)	(54,061)	(50,347)
Other deferred liabilities	(2,873)	(25,611)	24,063
Net Cash from Operating Activities	641,383	485,074	320,862
CASH FLOWS USED BY INVESTING ACTIVITIES:			
Additions to utility plant (excluding AFUDC - equity)	(499,374)	(656,074)	(1,314,697)
Proceeds from sale of asset	3,254	-	-
Customer advances for construction	(8,646)	(5,281)	(13,121)
Contributions in aid of construction	55,140	67,514	52,261
Investments and other property - net	(5)	(21,547)	2,690
Net Cash used by Investing Activities	(449,631)	(615,388)	(1,272,867)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of long-term debt	637,463	1,065,338	1,437,412
Retirement of long-term debt	(737,747)	(809,009)	(585,507)
Additional investment by parent company	-	-	146,600
Dividends paid	(74,000)	(112,000)	(54,907)
Net Cash from/(used by) Financing Activities	(174,284)	144,329	943,598
Net Increase in Cash and Cash Equivalents	17,468	14,015	(8,407)
Beginning Balance in Cash and Cash Equivalents	42,609	28,594	37,001
Ending Balance in Cash and Cash Equivalents	$ 60,077	$ 42,609	$ 28,594
Supplemental Disclosures of Cash Flow Information:			
Cash paid during period for:			
Interest	$ 226,138	$ 217,807	$ 170,281
Income taxes	$ 2	$ 2	$ 15,535
Significant non-cash transactions:			
Accrued construction expenses as of December 31,	$ 74,557	$ 117,226	$ 119,608
Capital lease obligations incurred	$ 15,336	$ -	$ -

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

NEVADA POWER COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in Thousands)

	Year Ended December 31,		
	2010	2009	2008
NET INCOME	$185,943	$134,284	$151,431
OTHER COMPREHENSIVE INCOME (LOSS)			
Change in compensation retirement benefits liability and amortization (Net of taxes $205, $(96) and $207 in 2010, 2009 and 2008, respectively)	$ (380)	$ 175	$ (393)
OTHER COMPREHENSIVE INCOME (LOSS)	$ (380)	$ 175	$ (393)
COMPREHENSIVE INCOME	$185,563	$134,459	$151,038

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

NEVADA POWER COMPANY

CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY

(Dollars in Thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholder's Equity
December 31, 2007	1,000	$1	$2,107,582	$ 272,435	$(3,278)	$2,376,740
Net Income				151,431		151,431
Capital contribution from parent			146,600			146,600
Compensation retirement benefits (net of taxes ($1,514))				(2,805)		(2,805)
Change in compensation retirement benefits liability and amortization (net of taxes $207)					(393)	(393)
Dividends Declared				(44,000)		(44,000)
December 31, 2008	1,000	1	2,254,182	377,061	(3,671)	2,627,573
Net Income				134,284		134,284
Tax benefit from stock options exercised			7			7
Change in compensation retirement benefits liability and amortization (net of taxes ($96))					175	175
Dividends Declared				(112,000)		(112,000)
December 31, 2009	1,000	1	2,254,189	399,345	(3,496)	2,650,039
Net Income				185,943		185,943
Tax benefit from stock options exercised			30			30
Change in compensation retirement benefits liability and amortization (net of taxes $205)					(380)	(380)
Dividends Declared				(74,000)		(74,000)
December 31, 2010	1,000	$1	$2,254,219	$ 511,288	$(3,876)	$2,761,632

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

SIERRA PACIFIC POWER COMPANY

CONSOLIDATED INCOME STATEMENTS

(Dollars in Thousands)

	Year Ended December 31,		
	2010	2009	2008
OPERATING REVENUES:			
Electric	$ 836,879	$ 957,130	$1,002,674
Gas	190,943	205,263	209,987
Total Operating Revenues	1,027,822	1,162,393	1,212,661
OPERATING EXPENSES:			
Fuel for power generation	233,065	294,121	283,342
Purchased power	143,642	130,977	293,527
Gas purchased for resale	137,702	153,607	170,468
Deferral of energy - electric - net	8,475	73,829	1,291
Deferral of energy - gas - net	9,789	7,636	(4,609)
Other operating expenses	149,946	170,849	141,064
Maintenance	32,808	31,290	30,787
Depreciation and amortization	106,807	106,048	89,528
Taxes other than income	24,593	23,447	21,304
Total Operating Expenses	846,827	991,804	1,026,702
OPERATING INCOME	180,995	170,589	185,959
OTHER INCOME (EXPENSE):			
Interest expense (net of AFUDC-debt: $1,912, $3,044 and $9,464)	(68,514)	(69,413)	(72,712)
Interest income (expense) on regulatory items	(9,348)	(5,743)	(2,087)
AFUDC-equity	2,883	3,249	12,524
Other income	16,748	13,276	12,819
Other expense	(9,985)	(7,648)	(8,318)
Total Other Income (Expense)	(68,216)	(66,279)	(57,774)
Income Before Income Tax Expense	112,779	104,310	128,185
Income tax expense (Note 10)	40,404	31,225	37,603
NET INCOME	$ 72,375	$ 73,085	$ 90,582

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

SIERRA PACIFIC POWER COMPANY

CONSOLIDATED BALANCE SHEETS

(Dollars in Thousands)

	December 31, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,552	$ 14,359
Accounts receivable less allowance for uncollectible accounts: 2010-$2,256; 2009-$2,966	129,306	146,883
Materials, supplies and fuel, at average cost	48,061	54,802
Risk management assets (Note 9)	531	5,656
Intercompany income taxes receivable	10,351	19,315
Deferred income taxes (Note 10)	53,282	46,414
Other current assets	11,633	16,056
Total Current Assets	262,716	303,485
Utility Property:		
Plant in service	3,516,421	3,419,190
Construction work-in-progress	83,500	89,102
Total (Note 1)	3,599,921	3,508,292
Less accumulated provision for depreciation	1,219,072	1,156,489
Total Utility Property, Net	2,380,849	2,351,803
Investments and other property, net (Note 4)	5,956	5,428
Deferred Charges and Other Assets:		
Regulatory assets (Note 3)	365,177	362,009
Regulatory asset for pension plans (Note 3)	131,734	130,283
Risk management assets (Note 9)	-	1,142
Other deferred charges and assets	45,268	40,837
Total Deferred Charges and Other Assets	542,179	534,271
Assets Held for Sale (Note 16)	155,322	147,158
TOTAL ASSETS	$3,347,022	$3,342,145

(Continued)

SIERRA PACIFIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

	December 31, 2010	December 31, 2009
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities:		
Current maturities of long-term debt (Note 6)	$ -	$ 15,000
Accounts payable	90,206	76,867
Accounts payable, affiliated companies	10,812	21,091
Accrued expenses	33,788	34,185
Dividends Declared	54,000	-
Risk management liabilities (Note 9)	10,465	27,749
Deferred energy (Note 3)	144,490	117,276
Other current liabilities	16,029	14,996
Total Current Liabilities	359,790	307,164
Long-term debt (Note 6)	1,195,775	1,282,225
Commitments and Contingencies (Note 13)		
Deferred Credits and Other Liabilities:		
Deferred income taxes (Note 10)	395,454	350,802
Deferred investment tax credit	11,949	13,843
Accrued retirement benefits	110,302	104,854
Risk management liabilities (Note 9)	-	1,068
Regulatory liabilities (Note 3)	202,131	175,732
Other deferred credits and liabilities	67,495	71,452
Total Deferred Credits and Other Liabilities	787,331	717,751
Liabilities Held for Sale (Note 16)	30,706	25,747
Shareholder's Equity:		
Common stock ($3.75 par value, 20,000,000 shares authorized, 1,000 shares issued and outstanding for 2010 and 2009)	4	4
Other paid-in capital	1,111,262	1,111,260
Retained earnings	(135,226)	(99,601)
Accumulated other comprehensive loss	(2,620)	(2,405)
Total Shareholder's Equity	973,420	1,009,258
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$3,347,022	$3,342,145

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

(Concluded)

SIERRA PACIFIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	For the Year Ended December 31,		
	2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 72,375	$ 73,085	$ 90,582
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	106,807	106,048	89,528
Deferred taxes and deferred investment tax credit	39,220	32,548	24,598
AFUDC-equity	(2,883)	(3,249)	(12,524)
Deferred energy	31,267	89,777	(1,494)
Gain on sale of asset	(7,575)	-	-
Amortization of other regulatory assets	35,799	39,146	(13,822)
Other, net	(7,929)	(8,778)	36,694
Changes in certain assets and liabilities:			
Accounts receivable	31,961	68,435	(59,701)
Materials, supplies and fuel	5,991	(4,436)	(2,453)
Other current assets	4,421	1,575	(376)
Accounts payable	2,050	(15,071)	(574)
Accrued retirement benefits	(2,523)	(2,227)	(47,923)
Other current liabilities	721	(3,038)	3,673
Risk management assets and liabilities	2,702	1,739	(1,302)
Other deferred assets	(3,513)	(3,495)	(702)
Other regulatory assets	(26,956)	(15,876)	(17,113)
Other deferred liabilities	887	(30,388)	31,536
Net Cash from Operating Activities	282,822	325,795	118,627
CASH FLOWS USED BY INVESTING ACTIVITIES:			
Additions to utility plant (excluding AFUDC-equity)	(143,216)	(187,058)	(220,806)
Proceeds from sale of asset	14,971	-	-
Customer advances for construction	(2,496)	(3,088)	1,140
Contributions in aid of construction	8,190	9,426	10,260
Investments and other property - net	(97)	(5,017)	1,611
Net Cash used by Investing Activities	(122,648)	(185,737)	(207,795)
CASH FLOWS USED BY FINANCING ACTIVITIES:			
Proceeds from issuance of long-term debt	37,726	353,534	697,739
Retirement of long-term debt	(148,707)	(462,144)	(489,434)
Investment by parent company	-	90,300	20,000
Dividends paid	(54,000)	(128,800)	(141,533)
Net Cash from/(used by) Financing Activities	(164,981)	(147,110)	86,772
Net Increase (Decrease) in Cash and Cash Equivalents	(4,807)	(7,052)	(2,396)
Beginning Balance in Cash and Cash Equivalents	14,359	21,411	23,807
Ending Balance in Cash and Cash Equivalents	$ 9,552	$ 14,359	$ 21,411
Supplemental Disclosures of Cash Flow Information:			
Cash paid during period for:			
Interest	$ 67,351	$ 69,966	$ 72,443
Income taxes	$ 752	$ 12	$ 19
Significant non-cash transactions:			
Accrued construction expenses as of December 31,	$ 11,570	$ 10,560	$ 24,374
Transfer of assets to accounts receivable	$ 16,830	$ -	$ -
Accrued dividends payable	$ 54,000	$ -	$ -

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

SIERRA PACIFIC POWER COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in Thousands)

	Year Ended December 31,		
	2010	2009	2008
NET INCOME	$72,375	$73,085	$90,582
OTHER COMPREHENSIVE INCOME (LOSS)			
Change in compensation retirement benefits liability and amortization (Net of taxes $116, $48 and $126 in 2010, 2009 and 2008, respectively)	$ (215)	$ (87)	$ (234)
OTHER COMPREHENSIVE LOSS	$ (215)	$ (87)	$ (234)
COMPREHENSIVE INCOME	$72,160	$72,998	$90,348

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

SIERRA PACIFIC POWER COMPANY
CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY
(Dollars in Thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholder's Equity
December 31, 2007	1,000	$4	$1,000,595	$ 3,325	$(2,084)	$1,001,840
Net Income				90,582		90,582
Capital contribution from parent			20,000			20,000
Tax benefit from stock options exercised			365			365
Compensation retirement benefits in (net of taxes ($857))				(1,593)		(1,593)
Change in compensation retirement benefits liability and amortization (net of taxes $126)					(234)	(234)
Dividends Declared				(233,000)		(233,000)
December 31, 2008	1,000	4	1,020,960	(140,686)	(2,318)	877,960
Net Income				73,085		73,085
Capital contribution from parent			90,300			90,300
Change in compensation retirement benefits liability and amortization (net of taxes $48)					(87)	(87)
Dividends Declared				(32,000)		(32,000)
December 31, 2009	1,000	4	1,111,260	(99,601)	(2,405)	1,009,258
Net Income				72,375		72,375
Tax benefit from stock options exercised			2			2
Change in compensation retirement benefits liability and amortization (net of taxes $116)					(215)	(215)
Dividends Declared				(108,000)		(108,000)
December 31, 2010	1,000	$4	$1,111,262	$(135,226)	$(2,620)	$ 973,420

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

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Basis of Presentation

The consolidated financial statements include the accounts of NV Energy, Inc. and its wholly-owned subsidiaries, Nevada Power Company, Sierra Pacific Power Company, Sierra Pacific Communications, Lands of Sierra, Inc., Sierra Energy Company dba e-three, Sierra Pacific Energy Company, Sierra Water Development Company, NVE Insurance and Sierra Gas Holding Company. All significant intercompany balances and intercompany transactions have been eliminated in consolidation.

The preparation of consolidated financial statements in conformity with GAAP 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 71% of the consolidated assets of NVE at December 31, 2010. NPC provides electricity to approximately 830,000 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 NVE include NPC's wholly-owned subsidiary, 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 29% of the consolidated assets of NVE at December 31, 2010. SPPC provides electricity to approximately 367,000 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. However, on January 1, 2011, SPPC sold its California assets, as discussed in Note 16, *Assets Held for Sale*. SPPC also provides natural gas service in Nevada to approximately 151,000 customers in an area of about 800 square miles in the Reno and Sparks areas. The consolidated financial statements of SPPC include the accounts of SPPC's wholly-owned subsidiaries, PPC, PPIC, 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 FERC.

Regulatory Accounting and Other Regulatory Assets

The Utilities' rates are subject to the approval of the PUCN and, in the case of SPPC, 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 regulatory accounting treatment as allowed by the Regulated Operations Topic of the FASC. However, on January 1, 2011, SPPC sold its California assets, as disclosed in Note 16, *Assets Held for Sale*. 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. The accounting guidance prescribes the method to be used to record the financial transactions of a regulated entity. The criteria for applying the accounting for regulated operations include the following: (i) rates are set by an independent third party regulator; (ii) regulated rates are designed to recover the specific costs 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 regulatory accounting treatment as allowed by the Regulated Operations Topic of the FASC are satisfied.

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 believes the existing regulatory assets are probable of recovery either because the Utilities received prior PUCN approval or due to regulatory precedent set for similar circumstances. Included in Note 3, *Regulatory Actions*, are details of other regulatory assets and liabilities, and their current regulatory treatment.

Equity Carrying Charges

In accordance with various regulatory orders, the Utilities' record carrying charges as allowed by the Regulated Operations Topic of the FASC. However, for financial reporting purposes the amounts representing equity carrying charges are not recognized until collected through regulated rates. As of December 31, 2010 and 2009, NPC and SPPC have accumulated approximately $12.0 million, and $1.1 million, and $2.5 million and $0.5 million, respectively, of equity related carrying charges that will be recognized into income when the corresponding regulatory assets are collected through rates. For further information, see Note 3, *Regulatory Actions*, Other Regulatory Assets table.

Deferred Energy Accounting

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.

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 in accordance with the provisions of the Regulated Operations Topic of the FASC. 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.

Nevada law requires the Utilities file annual DEAA applications 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.'' Nevada law also 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. See Note 3, *Regulatory Actions* for details regarding deferred energy balances.

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 or liability 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, post retirement and post employment benefits, vacations and payroll taxes; and an AFUDC which includes the cost of debt and equity capital associated with construction activity.

Utility Property

NVE, NPC and SPPC's gross utility property and CWIP are divided into the following major classes at December 31 (dollars in millions):

	2010			2009		
	NVE	NPC	SPPC	NVE	NPC	SPPC
Electric Generation assets	$ 4,056	$2,991	$1,065	$ 4,042	$2,990	$1,052
Electric Transmission assets	1,840	1,183	657	1,833	1,177	656
Electric Distribution assets	4,019	2,820	1,199	3,901	2,742	1,159
Electric General, Intangible plant	657	558	99	604	506	98
Electric CWIP	906	825	81	713	627	86
Natural Gas Distribution assets	303	-	303	294	-	294
Natural Gas General, Intangible plant	3	-	3	3	-	3
Natural Gas CWIP	2	-	2	3	-	3
Common Assets	191	-	191	157	-	157
Total Utility Property, Gross	**$11,977**	**$8,377**	**$3,600**	**$11,550**	**$8,042**	**$3,508**

AFUDC

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 2010, 2009 and 2008 were 8.32%, 8.57% and 9.06%, respectively. SPPC's AFUDC rates used during 2010, 2009 and 2008 were 7.85%, 7.96% and 8.54%, 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. However, on January 1, 2011, SPPC sold its California assets, as discussed in Note 16, *Assets Held for Sale*. 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, as authorized by the PUCN and stated as a percentage of the average depreciable property balances for those years, was approximately 2.99%, 2.74% and 2.56% during 2010, 2009 and 2008, respectively. SPPC's depreciation provision for 2010, 2009 and 2008, as authorized by the PUCN and stated as a percentage of the average cost of depreciable property, was approximately 3.02%, 3.07% and 2.77%, respectively.

The average estimated useful life for each major class of utility property, plant and equipment are as follows:

	Estimated Useful Lives	
	NPC	SPPC
Electric Generation	25 to 125 years	25 to 125 years
Electric Transmission	35 to 60 years	50 to 70 years
Electric Distribution	25 to 65 years	30 to 65 years
Gas Distribution	N/A	40 to 70 years
General Plant	5 to 50 years	5 to 65 years

Impairment of Long-Lived Assets

NVE, 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 the Property, Plant and Equipment Topic of the FASC.

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 and do not have any withdrawal restrictions.

Federal Income Taxes

NVE and the Utilities file a consolidated federal income tax return. Current income taxes are allocated based on NVE's and each Utility's respective taxable income or loss and tax credits as if each Utility filed a separate return.

NVE and the Utilities recognize deferred tax liabilities and assets for the future tax consequences of events that have been included in the financial statements or tax returns. 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. Deferred tax assets are also recorded for deductions incurred and credits earned that have not been utilized in tax returns filed or to be filed for tax years through the date of the financial statements. Management considers estimates of the amount and character of future taxable income by tax jurisdiction in assessing the likelihood of realization of deferred tax assets. If it is not more likely than not that a deferred tax asset will be realized in its entirety, a valuation allowance is recorded with respect to the portion estimated not likely to be realized.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more-likely-than-not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. NVE and the Utilities classify interest and penalties associated with unrecognized tax benefits as interest and other expense, respectively, within the income statement. No interest expense or penalties associated with unrecognized tax benefits have been recorded.

The Utilities reduce rates to reflect the current tax benefits associated with recognizing certain tax deductions sooner than when the expenses are recognized for financial reporting purposes. A regulatory asset is recorded for these amounts to reflect the future increases in income taxes payable that will be recovered from customers when these temporary differences reverse. The Utilities have been fully normalized since 1987. AFUDC-equity is recorded on an after-tax basis. Accordingly, a regulatory asset is recorded when AFUDC-equity is recognized. This regulatory asset reverses as the related plant is depreciated, resulting in an increase to the tax provision.

The Utilities also record regulatory liabilities for obligations to reduce rates charged customers for deferred taxes recovered from customers in prior years at corporate tax rates higher than the current tax rates. The reduction in rates charged customers will occur as the temporary differences resulting in the excess deferred tax liabilities reverse.

Investment tax credits are deferred and amortized over the estimated service lives of the related properties.

Revenues

Unbilled

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, line loss and the Utilities' current tariffs. Accounts receivable as of December 31, 2010, include unbilled receivables of $89 million and $60 million for NPC and SPPC, respectively. Accounts receivable as of December 31, 2009, include unbilled receivables of $103 million and $78 million for NPC and SPPC, respectively.

Alternative Revenues

As adopted by the PUCN in July 2010, the Utilities are authorized to recover lost revenue that is attributable to the measurable and verifiable effects associated with the implementation of efficiency and conservation programs approved by the PUCN. The Utilities account for the effects of such regulation in accordance with FASC 980-605-25, Alternative Revenue Programs which permits the recording of revenue if all of the following conditions are met: (1) the program allows for automatic adjustment of future rates, (2) the amount of revenues is objectively determinable and probable of recovery, and (3) the additional revenues will be collected within 24 months. See Note 3, *Regulatory Actions*, EEIR, for further discussion on the recording of such revenues.

REPR

REPR is a program that requires the Utilities to collect funds from customers and rebate all such collected amounts to customers based on qualified renewable energy programs, as such, REPR has no effect on Operating or Net Income. In 2010, REPR revenue and operating expense are presented net. REPR operating revenue and operating expense amounts presented net for the year ended December 31, 2010 for NVE, NPC and SPPC were $24.3 million, $11.1 million, and $13.2 million, respectively. REPR amounts for NVE and the Utilities for 2009 and 2008 were not material and were presented as operating revenues and as operating expense and did not have an effect on operating or net income.

Asset Retirement Obligations

The Asset Retirement and Environmental Liabilities Topic of the FASC provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the accounting guidance, 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 the accounting guidance 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.

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 and the Higgins Generating Station. Provisions of the lease require the lessees to remove the facilities upon request of the lessors at the expiration of the leases. Additionally, management has determined evaporative ponds, dry ash landfills, fuel storage tanks, asbestos and oils treated with Poly Chlorinated Biphenyl to have met the conditional asset retirement obligations as defined in the Asset Retirement and Environmental Liabilities Topic of the FASC.

The following table presents a reconciliation of the beginning and ending aggregate carrying amounts of asset retirement obligation for the years presented below (dollars in thousands):

	NVE		NPC		SPPC	
	2010	2009	2010	2009	2010	2009
Balance at January 1	$55,968	$ 57,627	$48,320	$ 50,216	$7,648	$7,411
Liabilities incurred in current period	-	7,888	-	7,888	-	-
Liabilities settled in current period	(34)	-	(34)	-	-	-
Accretion expense	3,877	4,258	3,383	3,776	494	482
Revision in estimated cash flows	(4,606)	(13,805)	(4,540)	(13,560)	(66)	(245)
Gain/Loss on settlement	(3)	-	(3)	-	-	-
Balance at December 31	$55,202	$ 55,968	$47,126	$ 48,320	$8,076	$7,648

Cost of Removal

In addition to the legal asset retirement obligations booked under the accounting guidance for asset retirement obligations, the Utilities have accrued for the cost of removing non-legal retirement obligations of other electric and gas assets. The amounts of such accruals included in regulatory liabilities in 2010 are approximately $208.8 million and $187.5 million for NPC and SPPC, respectively. In 2009, the amounts were approximately $192.9 million and $166.7 million.

Variable Interest Entities

In June 2009, the FASB amended existing guidance related to the consolidation of VIEs. NVE and the Utilities adopted this amendment on January 1, 2010. The amendment no longer allows the scope exception for contracts which an entity was unable to obtain financial information from to be excluded from the primary beneficiary determination. As a result, NVE and the Utilities will continually perform an analysis to determine whether their variable interests give it controlling financial interest in a VIE which would require consolidation. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both the following characteristics: a) the power to direct the activities of a VIE that most significantly impact the entity's economic performance, and b) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. To identify potential variable interests, management reviewed contracts under leases, long term purchase power contracts, tolling contracts and jointly owned facilities. The Utilities identified certain long-term purchase power contracts that could be defined as variable interests. However, the Utilities are not the primary beneficiary as defined above, as they primarily lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions. The Utilities' maximum exposure to loss is limited to the cost of replacing these purchase power contracts if the providers 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. As of December 31, 2010, the carrying amount of assets and liabilities in the Utilities' balance sheets that relate to their involvement with VIEs are predominately related to working capital accounts and generally represent the amounts owed by the Utilities for the deliveries associated with the current billing cycle under the contracts.

Franchise Fees and Universal Energy Charges

NPC and SPPC, as agents for some state and local governments collect from customers franchise fees and universal energy charges (UEC) levied by the state or local governments on our customers. NPC and SPPC present such fees on a net basis, as such, fees are excluded from revenue and expense.

Recent Accounting Standards Updates

Fair Value Measurements and Disclosures

In January 2010, the FASB issued an update on the Fair Value Measurements and Disclosure Topic as reflected in the FASB Accounting Standards Codification for recurring and nonrecurring fair value measurements. The new accounting guidance adds requirements for disclosures about transfers into and out of Levels 1 and 2 and separate disclosures about purchases, sales, issuances and settlements relating to Level 3 measurements. It also clarifies existing fair value disclosures about the level of disaggregation and about inputs and valuation techniques used to measure fair value. In addition, the accounting update amends guidance on employers' disclosures about postretirement benefit plan assets to require disclosures by classes of assets instead of by major categories of assets. The guidance was effective for NVE and the Utilities as of January 1, 2010, except for the disclosures about purchases, sales, issuances and settlements in the roll forward activity in Level 3 fair value measurements. Those disclosures will be effective for NVE and the Utilities as of January 1, 2011. The adoption of this guidance did not have, nor is expected to have, a significant impact on the disclosure requirements for NVE and the Utilities.

NOTE 2. SEGMENT INFORMATION

The Utilities operate three regulated business segments which are NPC electric, SPPC electric and SPPC natural gas service, which are reported in accordance with Segment Reporting of the FASC. Electric service is provided to Las Vegas and surrounding Clark County by NPC, and to northern Nevada and the Lake Tahoe area of California by SPPC. However, on January 1, 2011, SPPC sold its California assets, as discussed in Note 16, *Assets Held for Sale*. Natural gas services are provided by SPPC in the Reno-Sparks area of Nevada. Other information includes amounts below the quantitative thresholds for separate disclosure.

Operational information of the different business segments is set forth below based on the nature of products and services offered. NVE evaluates performance based on several factors, of which the primary financial measure is business segment gross margin. Gross margin, which the Utilities calculate as operating revenues less energy costs, provides a measure of income available to support the other operating expenses of the Utilities. Operating expenses are provided by segment in order to reconcile to operating income as reported in the consolidated financial statements for the years ended December 31 (dollars in thousands):

2010

	NVE Consolidated	NVE Other	NPC Electric	SPPC Total	SPPC Electric	SPPC Gas	SPPC Reconciling Eliminations[1]
Operating Revenues	$ 3,280,222	$ 23	$2,252,377	$1,027,822	$ 836,879	$190,943	
Energy Costs:							
Fuel for power generation	821,484	-	588,419	233,065	233,065	-	
Purchased power	648,881	-	505,239	143,642	143,642	-	
Gas purchased for resale	137,702	-	-	137,702	-	137,702	
Deferred energy	113,107	-	94,843	18,264	8,475	9,789	
	1,721,174	-	1,188,501	532,673	385,182	147,491	
Gross Margin	$ 1,559,048	$ 23	$1,063,876	$ 495,149	$ 451,697	$ 43,452	
Other operating expense	414,241	3,760	260,535	149,946			
Maintenance	104,567	-	71,759	32,808			
Depreciation and amortization	333,059	-	226,252	106,807			
Taxes other than income	62,746	235	37,918	24,593			
Operating Income	$ 644,435	$ (3,972)	$ 467,412	$ 180,995			
Assets	$11,669,668	$ 20,821	$8,301,824	$3,347,022	$3,022,257	$291,123	$33,643
Capital expenditures[2]	$ 629,496	$(13,094)	$ 499,374	$ 143,216	$ 131,579	$ 11,637	

2009

	NVE Consolidated	NVE Other	NPC Electric	SPPC Total	SPPC Electric	SPPC Gas	SPPC Reconciling Eliminations[1]
Operating Revenues	$ 3,585,798	$ 28	$2,423,377	$1,162,393	$ 957,130	$205,263	
Energy Costs:							
Fuel for power generation	881,768	-	587,647	294,121	294,121	-	
Purchased power	758,736	-	627,759	130,977	130,977	-	
Gas purchased for resale	153,607	-	-	153,607	-	153,607	
Deferred energy	289,076	-	207,611	81,465	73,829	7,636	
	2,083,187	-	1,423,017	660,170	498,927	161,243	
Gross Margin	$ 1,502,611	$ 28	$1,000,360	$ 502,223	$ 458,203	$ 44,020	
Other operating expense	453,413	2,699	279,865	170,849			
Maintenance	102,309	-	71,019	31,290			
Depreciation and amortization	321,921	-	215,873	106,048			
Taxes other than income	60,885	197	37,241	23,447			
Operating Income	$ 564,083	$ (2,868)	$ 396,362	$ 170,589			
Assets	$11,413,463	$(25,053)	$8,096,371	$3,342,145	$2,997,116	$305,434	$39,595
Capital expenditures	$ 843,132		$ 656,074	$ 187,058	$ 171,036	$ 16,022	

2008

	NVE Consolidated	NVE Other	NPC Electric	SPPC Total	SPPC Electric	SPPC Gas	SPPC Reconciling Eliminations[1]
Operating Revenues	$ 3,528,113	$ 25	$2,315,427	$1,212,661	$1,002,674	$209,987	
Energy Costs:							
Fuel for power generation	1,039,267	-	755,925	283,342	283,342	-	
Purchased power	974,343	-	680,816	293,527	293,527	-	
Gas purchased for resale	170,468	-	-	170,468	-	170,468	
Deferred energy	(10,265)	-	(6,947)	(3,318)	1,291	(4,609)	
	2,173,813	-	1,429,794	744,019	578,160	165,859	
Gross Margin	$ 1,354,300	$ 25	$ 885,633	$ 468,642	$ 424,514	$ 44,128	
Other operating expense	394,019	3,719	249,236	141,064			
Maintenance	94,069	-	63,282	30,787			
Depreciation and amortization	260,608	-	171,080	89,528			
Taxes other than income	53,525	152	32,069	21,304			
Operating Income	$ 552,079	$ (3,846)	$ 369,966	$ 185,959			
Assets	$11,347,870	$(20,712)	$7,904,147	$3,464,435	$3,113,539	$315,095	$35,801
Capital expenditures	$ 1,535,503		$1,314,697	$ 220,806	$ 202,011	$ 18,795	

(1) The reconciliation of segment assets at December 31, 2010, 2009 and 2008 to the consolidated total includes the following unallocated amounts:

	2010	2009	2008
Other investments	$ 5,956	$ 5,428	$ -
Cash	9,552	14,359	21,411
Deferred charges-other	18,135	19,808	14,390
	$33,643	$39,595	$35,801

(2) The capital expenditures for NVE Other at December 31, 2010 includes $13.1 million proceeds from the sale of assets between SPPC and SPCOM.

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. However, on January 1, 2011, SPPC sold its California assets, as discussed further in Note 16, *Assets Held for Sale*. 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.

As a result of regulation, the Utilities are required to file annual electric and gas DEAA cases by March 1, quarterly BTER updates for the Utilities' electric and gas departments and triennial GRCs. A DEAA case is filed to recover/refund any under/over collection of prior energy costs and the BTER updates recover current energy costs. The cumulative deferred energy balances include any balances remaining from the previously authorized DEAA filing, along with the under/over collection of the energy costs incurred since the last filing. A GRC filing is to set rates to recover operation and maintenance expenses, depreciation, taxes and provide a return on invested capital. Detailed below are Deferred Energy Costs which relate to the DEAA and BTER filings and further below are other regulatory assets and liabilities which primarily relate to the GRCs. Additionally, significant pending or settled rate cases are discussed below.

The following deferred energy amounts were included in the consolidated balance sheets as of December 31 for the years shown below (dollars in thousands):

	2010			
	NVE Total	NPC Electric	SPPC Electric	SPPC Gas
Nevada Deferred Energy				
Cumulative Balance authorized in 2010 DEAA[(1)]	$(220,064)	$(102,398)[(2)]	$(100,625)	$(17,041)
2010 Amortization	74,215	22,441	40,682	11,092
2010 Deferred Energy Over Collections[(3)]	(184,776)	(106,178)	(55,615)	(22,983)
Nevada Deferred Energy Balance at December 31, 2010 - Subtotal	$(330,625)	$(186,135)	$(115,558)	$(28,932)
Cumulative CPUC balance[(4)]	(3,210)	-	(3,210)	-
Reinstatement of deferred energy (effective 6/07, 10 years)	132,409	132,409	-	-
Total	$(201,426)	$ (53,726)	$(118,768)	$(28,932)
Deferred Assets				
Deferred energy	$ 117,623	$ 117,623	$ -	$ -
Current Liabilities				
Deferred energy	(315,839)	(171,349)	(115,558)	(28,932)
Liabilities held for sale	(3,210)	-	(3,210)	-
Total	$(201,426)	$ (53,726)	$(118,768)	$(28,932)

(1) These deferred costs include PUCN ordered adjustments.

(2) Refer to NPC DEAA under "Settled Regulatory Actions" below for separate discussion regarding the NPC rate offset of their 2010 cumulative balance against their deferred rate increase included in other regulatory assets.

(3) These deferred over collections are to be requested in March 2011 DEAA filings.

(4) Refer to Note 16, *Assets Held For Sale*.

	2009			
	NVE Total	NPC Electric	SPPC Electric	SPPC Gas
Nevada Deferred Energy				
Cumulative Balance authorized in 2009 DEAA(1)	$ 41,282	$ 74,885(1)	$ (24,870)	$ (8,733)
2009 Amortization	9,116	171	5,817	3,128
2009 Deferred Energy Over Collections(2)	(266,400)	(173,782)	(81,227)	(11,391)
Nevada Deferred Energy Balance at December 31, 2009 - Subtotal	(216,002)	(98,726)	(100,280)	(16,996)
Cumulative CPUC balance(3)	842	-	842	-
Western Energy Crisis Rate Case (effective 6/07, 3 years)	16,263	16,263	-	-
Reinstatement of deferred energy (effective 6/07, 10 years)	147,297	147,297	-	-
Total	$ (51,600)	$ 64,834	$ (99,438)	$(16,996)
Current Assets				
Other deferred charges(3)	$ 842	$ -	$ 842	$ -
Deferred Assets				
Deferred energy	138,963	138,963	-	-
Current Liabilities				
Deferred energy	(191,405)	(74,129)	(100,280)	(16,996)
Total	$ (51,600)	$ 64,834	$ (99,438)	$(16,996)

(1) These deferred costs include PUCN ordered adjustments and will be included as an offset to 2009 Deferred Energy Over-Collections within the February 2010 DEAA filings.

(2) These deferred over collections are to be requested in February 2010 DEAA filings, and include PUCN ordered adjustments.

(3) Refer to Note 16, *Assets Held For Sale*.

As discussed in Note 1, *Summary of Significant Accounting Policies*, 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, pending or potential legislation. Detailed below are

Other Regulatory Assets and Liabilities included in the balance sheet of NVE, NPC and SPPC and their current regulatory treatment as of December 31 (dollars in thousands):

NVE
OTHER REGULATORY ASSETS AND LIABILITIES

DESCRIPTION	Remaining Amortization Period	AS OF DECEMBER 31, 2010 Receiving Regulatory Treatment Earning a Return[1]	Receiving Regulatory Treatment Not Earning a Return	Pending Regulatory Treatment	2010 Total	As of December 31, 2009 Total
Regulatory assets						
Loss on reacquired debt	Term of Related Debt	$ 84,692	$ -	$ -	$ 84,692	$ 81,951
Income taxes	Various	-	257,078	-	257,078	261,633
Risk management		-	30,726	-	30,726	48,586
Lenzie Generating Station	2042	-	77,524	-	77,524	75,949
Mohave Generating Station and deferred costs	2015	12,158	-	13,691[2]	25,849	21,076
Clark Generating Station Units 1-3	2012	2,551	6,082	-	8,633	14,388
Piñon Pine	Various thru 2029	28,949	10,011	-	38,960	40,935
Plant assets	Various thru 2031	2,150	1,004	-	3,154	3,634
Asset retirement obligations			-	55,182[2]	55,182	51,916
Nevada divestiture costs	2013	5,929	-	-	5,929	10,442
Merger transition/transaction costs	2016	-	13,276	-	13,276	17,186
Merger severance/relocation	2016	-	7,396	-	7,396	9,518
Merger goodwill	2046	-	261,863	-	261,863	269,697
Conservation programs/EEPR	Various thru 2015	101,151	-	106,773[3]	207,924	175,720
Renewable energy programs	2012	2,627	-	-	2,627	-
Peabody coal costs		-	17,738	-	17,738	17,366
Deferred Rate Increase	2011	91,678	-	-	91,678	95,483
Legal fees - Western Energy Crisis	2010	-	-	-	-	697
Union contract OPEB change	2017	8,126	-	-	8,126	9,275
Impact fees	2013	6,225	-	1,922[2]	8,147	5,001
Severance programs	2013	4,024	-	-	4,024	-
Generation studies	2013	-	3,003	-	3,003	1,474
Obsolete inventory	2013	-	766	2,327[2]	3,093	2,828
Other costs	Various thru 2017	209	9,283	11,045[3]	20,537	4,023
Subtotal		$350,469	$695,750	$190,940	$1,237,159	$1,218,778
Pensions		-	269,472	-	269,472	264,892
Total regulatory assets		$350,469	$965,222	$190,940	$1,506,631	$1,483,670
Regulatory liabilities						
Cost of removal	Various	$382,634	$ -	$ -	$ 382,634	$ 348,150
Income taxes	Various	-	19,506	-	19,506	22,128
Tracy Combined Cycle	2043	4,700	-	-	4,700	-
Gain on property sales	2013	7,151	-	-	7,151	-
SO2 allowances	Various thru 2016	316	-	-	316	499
Depreciation - customer advances	2013	2,923	-	-	2,923	5,744
Renewable energy programs	2012	10,234	-	-	10,234	7,236
Impact fees		-	-	650[2]	650	1,120
Other		-	-	-	-	1,142
Total regulatory liabilities		$407,958	$ 19,506	$ 650	$ 428,114	$ 386,019

NPC
OTHER REGULATORY ASSETS AND LIABILITIES

DESCRIPTION	AS OF DECEMBER 31, 2010					As of December 31, 2009 Total
	Remaining Amortization Period	Receiving Regulatory Treatment		Pending Regulatory Treatment	2010 Total	
		Earning a Return[1]	Not Earning a Return			
Regulatory assets						
Loss on reacquired debt	Term of Related Debt	$ 43,765	$ -	$ -	$ 43,765	$ 45,229
Income taxes	Various	-	174,022	-	174,022	173,336
Risk management		-	20,261	-	20,261	23,334
Lenzie Generating Station	2042	-	77,524	-	77,524	75,949
Mohave Generating Station and deferred costs	2015	12,158	-	13,691[2]	25,849	21,076
Clark Generating Station Units 1-3	2012	2,551	6,082	-	8,633	14,388
Asset retirement obligations		-	-	48,970[2]	48,970	46,323
Nevada divestiture costs	2012	3,492	-	-	3,492	6,285
Merger transition/transaction costs	2014	-	9,072	-	9,072	11,863
Merger severance/relocation	2014	-	3,316	-	3,316	4,336
Merger goodwill	2044	-	164,586	-	164,586	169,536
Conservation programs/EEPR	2015	69,502	-	99,510[3]	169,012	144,894
Renewable energy programs		-	-	-	-	-
Peabody coal costs		-	17,738	-	17,738	17,366
Deferred Rate Increase	2011	91,678	-	-	91,678	95,483
Legal fees - Western Energy Crisis	2010	-	-	-	-	697
Generation studies	2012	-	496	-	496	827
Obsolete inventory		-	-	2,151[2]	2,151	2,062
Other costs	2012	-	3,596	7,821	11,417	3,785
Subtotal		$223,146	$476,693	$172,143	$ 871,982	$ 856,769
Pensions		-	133,410	-	133,410	129,709
Total regulatory assets		$223,146	$610,103	$172,143	$1,005,392	$ 986,478
Regulatory liabilities						
Cost of removal	Various	$208,795	$ -	$ -	$ 208,795	$ 192,944
Income taxes	Various	-	6,557	-	6,557	7,149
SO2 allowances	Various thru 2016	316	-	-	316	499
Depreciation - customer advances	2012	1,868	-	-	1,868	3,113
Renewable energy programs	2012	7,797	-	-	7,797	4,320
Impact fees		-	-	650[2]	650	1,120
Other		-	-	-	-	1,142
Total regulatory liabilities		$218,776	$ 6,557	$ 650	$ 225,983	$ 210,287

SPPC
OTHER REGULATORY ASSETS AND LIABILITIES

DESCRIPTION	AS OF DECEMBER 31, 2010					As of December 31, 2009 Total
	Remaining Amortization Period	Receiving Regulatory Treatment		Pending Regulatory Treatment	2010 Total	
		Earning a Return(1)	Not Earning a Return			
Regulatory assets						
Loss on reacquired debt	Term of Related Debt	$ 40,927	$ -	$ -	$ 40,927	$ 36,722
Income taxes	various	-	83,056	-	83,056	88,297
Risk management		-	10,465	-	10,465	25,252
Piñon Pine	Various thru 2029	28,949	10,011	-	38,960	40,935
Plant assets	Various thru 2031	2,150	1,004	-	3,154	3,634
Asset retirement obligations		-	-	6,212(2)	6,212	5,593
Nevada divestiture costs	2013	2,437	-	-	2,437	4,157
Merger transition/transaction costs	2016	-	4,204	-	4,204	5,323
Merger severance/relocation	2016	-	4,080	-	4,080	5,182
Merger goodwill	2046	-	97,277	-	97,277	100,161
Conservation programs/EEPR	2013	31,649	-	7,263(3)	38,912	30,826
Renewable energy programs	2012	2,627	-	-	2,627	-
Union contract OPEB change	2017	8,126	-	-	8,126	9,275
Impact fees	2013	6,225	-	1,922(2)	8,147	5,001
Severance programs	2013	4,024	-	-	4,024	-
Generation studies	2013	-	2,507	-	2,507	647
Obsolete inventory	2013	-	766	176(2)	942	766
Other costs	Various thru 2017	209	5,687	3,224(3)	9,120	238
Subtotal		$127,323	$219,057	$ 18,797	$ 365,177	$ 362,009
Pensions		-	131,734	-	131,734	130,283
Total regulatory assets		$127,323	$350,791	$ 18,797	$ 496,911	$ 492,292
Regulatory liabilities						
Cost of removal	Various	$173,839	$ -	$ -	$ 173,839	$ 155,206
Income taxes	Various	-	12,949	-	12,949	14,979
Tracy Combined Cycle	2043	4,700	-	-	4,700	-
Gain on property sales	2013	7,151	-	-	7,151	-
Depreciation - customer advances	2013	1,055	-	-	1,055	2,631
Renewable energy programs	2012	2,437	-	-	2,437	2,916
Total regulatory liabilities		$189,182	$ 12,949	$ -	$ 202,131	$ 175,732

(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.

(2) Pending regulatory treatment includes either amounts which have prior regulatory precedent or have been approved and are subject to prudency review.

(3) Assets which are allowed to earn a carrying charge until included in rates. Reference Note 1, *Summary of Significant Accounting Policies*, Equity Carrying Charges.

Pending Regulatory Actions

Nevada Power Company and Sierra Pacific Power Company

Ely Energy Center

In February 2011, NVE and the Utilities cancelled plans to construct the EEC due to increasing environmental and economic uncertainties. The PUCN had previously approved the Utilities spending on the EEC up to $130 million, of which the Utilities have spent and recorded as an other deferred asset approximately $67 million as of December 31, 2010. Management believes the amounts expended through December 31, 2010 are probable of recovery. In June 2009, the Utilities filed to withdraw the initial construction application under the Utility Environmental Protection Act (UEPA) filed in 2006 due to postponing the construction of the EEC. Simultaneously, the Utilities filed a new UEPA application for the construction of a transmission line. In the SPPC 2010 Electric GRC discussed below, the Utilities were ordered to file a separate application concurrent with the filing of NPC's GRC, expected in June 2011, to determine the reasonableness of the EEC project development costs and propose reclassification of these costs from a deferred debit to a regulatory asset.

Energy Efficiency Implementation Rate (EEIR) and Energy Efficiency Program Rate (EEPR)

EEIR

In 2009, the Nevada Legislature passed Senate Bill 358, which required the PUCN to adopt regulations authorizing an electric utility to recover lost revenue that is attributable to the measurable and verifiable effects associated with the implementation of efficiency and conservation programs approved by the PUCN. As a result, the PUCN opened Docket No. 0-07016 to amend and adopt the regulation. The regulation was adopted by the Legislature on July 22, 2010. The Utilities will account for the effects of such regulation in accordance with FASC 980-605-25, Alternative Revenue Programs. Accordingly, as of August 1, 2010, the Utilities are recording the amount of additional revenues which are objectively determinable and probable of recovery and are attributable to reduced kWh sales related to our energy efficiency programs, prior to their inclusion in rates. In March 2011, the Utilities will make an additional rate filing to clear the accumulated regulatory asset account between August 1, 2010 and December 31, 2010, with rates effective in October 2011. In October 2010, the Utilities filed to set base rates beginning mid 2011 to recover approximately $35.1 million and $7.6 million for NPC and SPPC, respectively, for estimated reduced kWh sales related to our energy efficiency programs in 2011. Annually, thereafter, the Utilities will make a filing in March, to adjust rates and set a clearing rate or EEIR for over or under collected balances, effective in October of the same year.

As a result of the Utilities' applications for interim base EEIR filed in October 2010, the PUCN's staff filed a Motion for Partial Summary Judgment (Motion) on December 1, 2010. The Motion contends that the Utilities' original filings, which requested recovery of lost revenues associated with the measurable and verifiable effects of energy efficiency programs for programs implemented prior to July 2010, were inconsistent with Nevada law. The Utilities opposed the Motion on December 16, 2010. The Commission heard oral argument on the Motion on January 20, 2011. On February 3, 2011, the PUCN denied the Motion without prejudice.

EEPR

In addition, the regulation approved the transition of the recovery of DSM program costs from general rates (filed every 3 years) to recovery through independent annual rate filings. Accordingly, in their filing made in October 2010, the Utilities have requested to set base rates beginning mid 2011 to recover the cost of implementing DSM program costs of approximately $70.6 million and $12.1 million for NPC and SPPC, respectively. Costs accumulated between August 1, 2010 and December 31, 2010 will be requested for recovery in the March 2011 filing with rates effective October 2011. Thereafter, annual filings will be made in March with rates effective October of the same year. Beginning August 1, 2010, the Utilities are authorized to net total DSM program costs with the DSM Base Rate recovery or EEPR and record the differential to a regulatory asset account and corresponding offset to expense. However, as ordered by the PUCN, and since there will be no EEPR until mid 2011, all DSM program costs are accumulated in a regulatory asset account. As of December 31, 2010, NPC's and SPPC's balance sheets included approximately $25.4 million and $5.7 million, respectively, with an offset to expense for this program. The new regulation will permit a more timely recovery of revenues to offset the expense of implementing demand side management programs.

Settled Regulatory Actions

Nevada Power Company

NPC Harry Allen Regulatory Asset Filing

In December 2010, NPC filed a petition with the PUCN seeking permission to establish a regulatory asset related to the 500 MW (nominally rated) expansion at the Harry Allen Generating Station. The petition seeks to recover foregone return, depreciation expense and incremental operating and maintenance expense incurred between June 1, 2011, the approved in service date, and December 31, 2011, that due to regulatory lag will not be recovered. In January 2011, the PUCN voted to set the petition for further proceeding.

NPC 2010 DEAA

In March 2010, NPC filed an application to create a new DEAA rate. In its application, NPC requested to refund $102 million of deferred fuel and purchased power costs. Separately, NPC filed a petition to offset the NPC DEAA over collection (credit balance) of $102 million against the deferred BTGR debit balance of $95.8 million. The BTGR debit balance of $95.8 million was a result of NPC's 2008 GRC, which granted NPC approval to defer billings of its rate increase from July 1, 2009 to December 31, 2009 in a regulatory asset for which NPC recognized revenues in 2009. The PUCN consolidated both dockets for hearing purposes.

In September 2010, the PUCN accepted a stipulation for the DEAA and BTGR offset applications, which will result in an overall revenue decrease of $9.2 million or 0.41% for the period October 1, 2010 through December 31, 2011.

NPC 2009 DEAA

In February 2009, NPC filed an application to create a new DEAA rate. In this application, NPC requested to increase rates by $72.1 million, an increase of 3.18%, while recovering $77.5 million of deferred fuel and purchased power costs. In September 2009, the PUCN ordered that the DEAA rate remain set at $0.00 per kWh, in addition, the PUCN also ordered a slight increase to the TRED charge and a slight decrease to the REPR which resulted in a net decrease to revenues of $4.6 million, or a 0.20% decrease. The PUCN found that NPC's purchases of fuel and power were prudent and approved those costs for the test period which were included as an offset to 2009 deferred energy over-collections within the 2010 DEAA filing.

NPC 2008 GRC

In December 2008, NPC filed its statutorily required GRC with the PUCN and further updated the filing in February and March 2009. The filing, as updated, requested an ROE of 11.0% and ROR of 8.88% and an increase to general revenues of $305.7 million.

The PUCN issued its order in June 2009, which resulted in the following significant items:

- Increase in general rates by $222.7 million, approximately a 9.8% increase;
- ROE and ROR of 10.5% and 8.53%, respectively;
- Authorized to recover the costs of major plant additions including the purchase of the Higgins Generating Station, construction of Clark Peaking Units, an upgrade to the emission control systems on existing units at the Clark Generating Station, installation of environmental equipment upgrades at the Reid Gardner Generating Station and new transmission and distribution projects;
- CWIP as of November 2008 in rate base for the construction of a 500 MW (nominally rated) combined cycle unit at the existing Harry Allen Generating Station site; and
- A two part implementation of the rate increase to be billed to customers. The part I rate increase was effective July 1, 2009 and resulted in a 3% increase to all core customer classes. The part II rate increase was effective January 1, 2010 and implemented the remainder of the increase to all core customer classes. The PUCN granted approval for NPC to track and record the difference between the 9.8% general rate increase and billings associated with the part I rate increase each month in a regulatory asset account and permitted NPC to record a carrying charge on these amounts. Reference Equity Carrying Charges in Note 1, *Summary of Significant Accounting Policies* for further discussion on the recognition of the carrying charge. This regulatory asset was used to offset the NPC 2010 DEAA over collection, as discussed above.

NPC 2008 DEAA and BTER Update

In February 2008, NPC filed applications to create a new DEAA rate and to update the going forward BTER. In these applications, NPC requested to decrease rates by $116.3 million, a decrease of 5.04% while recovering $36 million of deferred fuel and purchased power costs. The going forward BTER became effective April 1, 2008. The PUCN issued its order in September 2008 setting the DEAA rate for all customers at $0.00 per kWh effective October 1, 2008. The PUCN found that NPC's purchases of fuel and power were prudent and approved those costs for the test period.

Mohave Generating Station

NPC owns approximately 14% of the Mohave Generating Station. Southern California Edison is the operating partner of the Mohave Generating Station.

When operating, the Mohave Generating Station 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 the Mohave Generating Station 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 Generating Station, 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, the Mohave Generating Station Units 1 and 2 ceased operations as of January 2006 as the new emission limits were not met. Due to the lack of resolutions 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 Generating Station suspended operation, pending resolution of these issues. However, in June 2006, majority stake holder Southern California Edison 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 expired and the operating agreement between the Owners expired in July 2006. The Owners are discussing the negotiation of new agreements that would address the potential disposition of the assets and rights, title, interest and obligations in the Mohave Generating Station.

Included in other regulatory assets is approximately $12.2 million, which has been approved by the PUCN and included in rates. All other costs for Mohave Generating Station, including approximately $13.7 million of decommissioning costs continue to be accumulated in other regulatory assets as incurred and will be requested for recovery in future GRC's, see the Other Regulatory Assets/Liabilities table above.

In June 2009, Southern California Edison announced that the Mohave Generating Station will be dismantled and its operating permits terminated following a December 2005 suspension of operations due to pending environmental matters. NPC believes it will continue to recover the costs for the Mohave Generating Station through the regulatory process and does not expect the dismantling of the plant to have a material impact on its financial condition.

Sierra Pacific Power Company

SPPC California Divestiture Filing

In October 2009, SPPC and CalPeco filed an application with the CPUC requesting approval of the transaction in which SPPC has agreed to sell its California electric distribution and generation assets to CalPeco. Upon closing of the transaction, SPPC will transfer to CalPeco all of its California electric distribution and generation assets and approximately 46,000 retail electric customers. The CPUC held hearings in June 2010 and in October 2010 issued a decision approving the transaction. Separately in December 2009, SPPC filed an application with the PUCN requesting PUCN approval of the transaction. In July 2010, SPPC filed certain components of the transaction under its IRP process and requested consolidation with the previously filed application. The PUCN approved the transaction in December 2010. In January 2011, the assets were sold, see Note 16, *Assets Held for Sale*.

SPPC 2010 Nevada Gas DEAA

In March 2010, SPPC filed an application to create a new DEAA rate. In September, the PUCN accepted a stipulation to decrease rates by $8.3 million, a decrease of 4.69%, while refunding approximately $17 million of deferred gas costs. The new DEAA rate became effective October 1, 2010.

SPPC 2010 Nevada Electric DEAA

In March 2010, SPPC filed an application to create a new DEAA rate. In September, the PUCN accepted a stipulation to decrease rates by $47.0 million, a decrease of 6.31%, while refunding $101 million of deferred fuel and purchased power costs. The new DEAA rate became effective October 1, 2010.

SPPC 2010 Electric GRC

In June 2010, SPPC filed its statutorily required GRC for its Nevada electric operations and further updated the filing in July and August 2010. The filing, as updated, requested an ROE of 10.75% and ROR of 8.14% and an increase to general revenues of $29.3 million.

The PUCN issued its order in December 2010, which resulted in the following significant items:

- Increase in general rates by $13.1 million, approximately a 1.90% increase effective January 1, 2011;
- ROE and ROR of 10.10% and 7.86%, respectively;
- Authorized to recover new electric and common plant additions along with ordinary changes in operating expense, maintenance expense and administrative and general costs;
- Ordered to file a separate application concurrent with the filing of NPC's GRC, expected in June 2011, to determine the reasonableness of the EEC project development costs and propose reclassification of these costs from a deferred debit to a regulatory asset.

SPPC 2010 Gas GRC

In June 2010, SPPC filed a GRC for its gas operations and further updated the filing in July and August 2010. The filing, as updated, requested an ROE of 10.75% and ROR of 5.48% and an increase to general revenues of $4.3 million.

The PUCN issued its order in December 2010, which resulted in the following significant items:

- Increase in general rates by $2.7 million, approximately a 1.93% increase effective January 1, 2011;
- ROE and ROR of 10.00% and 5.15%, respectively;
- Authorized to recover new gas and common plant additions along with ordinary changes in operating expense, maintenance expense and administrative and general costs.

SPPC California GRC

In July 2008, SPPC filed a GRC with the CPUC and subsequently filed an amendment to the original filing in December 2008. SPPC requested an ROE of 11.4% and ROR of 8.81% and an increase in general revenues of $8.9 million. In July 2009, a settlement was filed with the CPUC, which includes the following:

- Increase in general rates of $5.5 million, approximately an 8% increase;
- ROE and ROR of 10.7% and 8.51%, respectively;
- Approval of authorization to recover the costs of major plant additions, which include the Tracy Generating Station, and distribution plant additions, as well as a decrease to the California Energy Efficiency Program; and
- Approval of a two-part mechanism to recover changes in non-energy cost adjustment clause costs incurred during the two years between rate cases.

The CPUC approved the settlement and rates were effective December 1, 2009. However, on January 1, 2011, SPPC sold its California assets, as discussed further in Note 16, *Assets Held for Sale*.

SPPC 2009 Nevada Electric DEAA

In February 2009, SPPC filed an application to create a new electric DEAA rate for Nevada customers. In this application, SPPC requested to decrease rates by $25.9 million, a decrease of 2.69%, while refunding $19.8 million of deferred fuel and purchased power costs. The PUCN issued its order in September 2009 decreasing rates by $30.8 million, a decrease of 3.19% and approving SPPC's purchases of fuel and power as prudent for the test period. The new credit DEAA rate became effective October 1, 2009.

SPPC 2009 Nevada Gas DEAA

In February 2009, SPPC filed an application to create a new gas DEAA rate for Nevada customers. In this application, SPPC requested to decrease rates by $8.7 million, a decrease of 4.71%, while refunding $8.7 million of deferred gas costs. The PUCN issued its order in September 2009 approving SPPC's requested rate decrease and approving SPPC's purchases of natural gas and propane as prudent for the test period. The new DEAA rate became effective October 1, 2009.

SPPC Nevada Gas DEAA and BTER Update

In December 2007, SPPC filed for the authority to implement quarterly BTER adjustments for its natural gas and liquefied propane gas services. The authority was approved in January 2008, and as a result, in February 2008, SPPC filed applications to create a new DEAA rate and to update the going forward BTER. In these applications, SPPC requested to decrease rates by $9.9 million, a decrease of 5.53%, while refunding an over collection of $11.4 million in deferred natural gas and liquid propane costs. The going forward BTER became effective April 1, 2008. The PUCN issued its order in October 2008 setting the DEAA rate at $0.00 per therm effective October 1, 2008 and approving SPPC's purchases of natural gas and propane for the test period as prudent.

SPPC Nevada Electric DEAA and BTER Update

In February 2008, SPPC filed applications to create a new DEAA rate and to update the going forward BTER. In these applications, SPPC requested to decrease rates by $42.1 million, a decrease of 4.57%, while refunding an over collection of $20.9 million in deferred fuel and purchased power costs. The going forward BTER became effective April 1, 2008. The PUCN issued its order in October 2008 setting the DEAA rate at $0.00 per kWh effective October 1, 2008. The PUCN found that SPPC's purchases of fuel and power were prudent and approved those costs for the test period.

SPPC California Energy Cost Adjustment Clause

In April 2008, SPPC filed to decrease rates by $12.2 million, a decrease of 15.2%. The CPUC approved the filing in August 2008. The rates requested in this filing were effective September 1, 2008. However, on January 1, 2011, SPPC sold its California assets, as discussed further in Note 16, *Assets Held for Sale*.

SPPC 2007 Nevada Electric GRC

In December 2007, SPPC filed its statutorily required electric GRC. The filing requested an ROE and ROR of 11.5% and 8.73%, respectively, and an increase to general revenues of $110.8 million.

The PUCN issued its order in June 2008, with rates effective July 1, 2008. The PUCN order resulted in the following significant items:

- Increase in general rates of $87.1 million, a 10.45% increase;
- ROE and ROR of 10.6% and 8.41%, respectively;
- Authorization to recover the costs of the new 541 MW (nominally rated) Tracy Generating Station; and
- Authorization to recover the projected operating and maintenance costs associated with the new Tracy Generating Station.

SPPC Piñon Pine

In its 2003 GRC, 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 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 IRP. While the convential 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 of May 24, 2004, the PUCN disallowed $43 million of unreimbursed costs associated with the Project. As a result, these amounts were expensed in 2004. SPPC filed a Petition for Judicial Review with the Second Judicial District Court of Nevada (District Court) in June 2004 (CV04-01434). On January 25, 2006, the District Court vacated the PUCN's disallowance in SPPC's 2003 GRC and remanded the case back to the PUCN for further review as to whether the costs were justly and reasonably incurred (''the 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 the 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 the Order, remanded the matter back to the PUCN for further review.

On March 18, 2008, the PUCN issued an order to place $5.8 million (Nevada jurisdiction) of the previously disallowed $43 million unreimbursed costs in a regulatory asset account without a carrying charge. As a result of this order and in accordance with FASC accounting for regulated operations and abandonments, SPPC recognized approximately $4.3 million in income for the year ended December 31, 2008. The remaining difference of $1.5 million will be recognized over an approximate six year period. The time for any party to appeal the PUCN's decision ended in June 2008 and no appeals were filed.

FERC Matters

California Wholesale Spot Market Refunds

NPC and SPPC are participants in a FERC proceeding wherein California parties have been authorized to recalculate, or mitigate, the prices they paid for wholesale spot market power between October 2, 2000 and June 20, 2001. Both of the Utilities made spot market sales that are eligible for mitigation, therefore the Utilities expect to pay refunds resulting from the recalculated energy prices. Parties have contested the FERC's decision to limit the timeframe for the recalculations and a Ninth Circuit decision remanded a related issue to the FERC, therefore NPC and SPPC are not able to determine the eventual magnitude of refunds that may result from this FERC process. NPC and SPPC are actively participating in this docket to ensure their interests are represented.

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 developed and filed a cost based filing, which justified a $6 million reduction to the estimated refunds resulting in a $13 million refund.

CAISO and CALPX currently owe NPC approximately $19 million for power delivered during the same timeframe for which NPC had fully reserved for in 2001. As such, if NPC is ordered to pay CAISO and CALPX the refunds discussed above, NPC would apply such payments towards NPC's receivable of $19 million from CAISO and CALPX.

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 timeframe would result in a $4 million refund.

CAISO and CALPX currently owe SPPC approximately $1 million for power delivered during the same timeframe and SPPC recorded a reserve against the $1 million receivable in 2001. In 2009, 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 the following as of December 31 (dollars in thousands):

	2010	2009
NVE		
Investments held in Rabbi Trust[1]	$29,348	$26,490
Cash Value-Life Insurance	2,646	2,512
Non-utility property of NEICO	5,659	5,338
Non-utility property of SPC[2]	-	4,130
Property not designated for Utility use	23,608	12,255
Other non-utility property	352	444
	$61,613	$51,169

	2010	2009
NPC		
Investments held in Rabbi Trust[1]	$23,810	$21,492
Cash Value-Life Insurance	2,646	2,512
Non-utility property of NEICO	5,659	5,338
Property not designated for Utility use	23,190	11,825
	$55,305	$41,167

	2010	2009
SPPC		
Investments held in Rabbi Trust[1]	$ 5,538	$ 4,998
Property not designated for Utility use	418	430
	$ 5,956	$ 5,428

(1) Rabbi trust assets represent non-qualified deferred compensation and certain defined benefit plans, which consist of actively traded money market and equity funds with quoted prices in active markets which are considered level 1 in the fair value hierarchy. The balance also includes life insurance policies, which are recorded at its cash surrender value of $9.5 million on the consolidated balance sheet, which are considered level 2 in the fair value hierarchy.

(2) SPC's, a wholly-owned subsidiary of NVE, assets were purchased by SPPC in May 2010 and transferred to the Utility.

NOTE 5. JOINTLY OWNED FACILITIES

At December 31, 2010 and 2009, NPC and SPPC owned the following undivided interests in jointly owned electric utility facilities (dollars in thousands):

	2010				
	% Owned	Plant in Service	Accumulated Depreciation	Net Plant in Service	CWIP
NPC					
Navajo Generating Station	11.3%	$249,646	$141,326	$108,320	$ 1
Reid Gardner Generating Station No. 4	32.2%	165,795	98,047	67,748	21,016
Silverhawk Generating Station	75.0%	250,790	47,194	203,596	183
		$666,231	$286,567	$379,664	$21,200
SPPC					
Valmy Generating Station	50.0%	$313,378	$210,165	$103,213	$ 5,605

	2009				
	% Owned	Plant in Service	Accumulated Depreciation	Net Plant in Service	CWIP
NPC					
Navajo Generating Station	11.3%	$249,193	$135,732	$113,461	$ 341
Reid Gardner Generating Station No. 4	32.2%	174,671	103,961	70,710	16,368
Silverhawk Generating Station	75.0%	246,098	39,715	206,383	2
		$669,962	$279,408	$390,554	$16,711
SPPC					
Valmy Generating Station	50.0%	$304,131	$195,479	$108,652	$ 3,023

The amounts for Navajo Generating Station 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 these jointly owned facilities. NPC's share of the operating expenses for these facilities is included in the corresponding operating expenses in its consolidated statement of income.

Reid Gardner Generating Station Unit No. 4 is owned by the CDWR (67.8%) and NPC (32.2%). NPC is the operating agent. Contractually, NPC is entitled to receive 25 MW of base load capacity and 232 MW of peaking capacity, subject to certain operating limitations. The contract expires in 2013. NPC's share of the operating expenses for this facility 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 SNWA. NPC's owns 75% and its share of direct operation and maintenance expenses is included in its accompanying consolidated income statements.

SPPC and Idaho Power Company each own a 50% undivided 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 Generating Station are included in its accompanying consolidated income statements.

NOTE 6. LONG-TERM DEBT

NVE's, NPC's and SPPC's long-term debt consists of the following as of December 31 (dollars in thousands):

	2010				2009			
	Consolidated	NVE Holding Co.	NPC	SPPC	Consolidated	NVE Holding Co.	NPC	SPPC
Long-Term Debt:								
Secured Debt								
General and Refunding Mortgage Securities								
8.25% NPC Series A due 2011	$ 350,000	$ -	$ 350,000	$ -	$ 350,000	$ -	$ 350,000	$ -
6.50% NPC Series I due 2012	130,000	-	130,000	-	130,000	-	130,000	-
5.875% NPC Series L due 2015	250,000	-	250,000	-	250,000	-	250,000	-
5.95% NPC Series M due 2016	210,000	-	210,000	-	210,000	-	210,000	-
6.65% NPC Series N due 2036	370,000	-	370,000	-	370,000	-	370,000	-
6.50% NPC Series O due 2018	325,000	-	325,000	-	325,000	-	325,000	-
6.75% NPC Series R due 2037	350,000	-	350,000	-	350,000	-	350,000	-
6.50% NPC Series S due 2018	500,000	-	500,000	-	500,000	-	500,000	-
7.375% Series U due 2014	125,000	-	125,000	-	125,000	-	125,000	-
7.125% Series V due 2019	500,000	-	500,000	-	500,000	-	500,000	-
5.375% Series X due 2040	250,000	-	250,000	-	-	-	-	-
6.25% SPPC Series H due 2012	-	-	-	-	100,000	-	-	100,000
6.00% SPPC Series M due 2016	450,000	-	-	450,000	450,000	-	-	450,000
6.75% SPPC Series P due 2037	251,742	-	-	251,742	251,742	-	-	251,742
5.45% SPPC Series Q due 2013	250,000	-	-	250,000	250,000	-	-	250,000
Variable Rate Debt (Secured by General and Refunding Mortgage Securities)								
NPC IDRB Series 2000A due 2020	98,100	-	98,100	-	98,100	-	98,100	-
NPC PCRB Series 2006 due 2036	37,700	-	37,700	-	37,700	-	37,700	-
NPC PCRB Series 2006A due 2032	37,975	-	37,975	-	37,975	-	37,975	-
SPPC PCRB Series 2006A due 2031	58,200	-	-	58,200	58,200	-	-	58,200
SPPC PCRB Series 2006B due 2036	75,000	-	-	75,000	75,000	-	-	75,000
SPPC PCRB Series 2006C due 2036	81,475	-	-	81,475	81,475	-	-	81,475
SPPC WFRB Series 2007A due 2036	-	-	-	-	-	-	-	-
Revolving Credit Facilities	15,000	-	-	15,000	125,000	-	110,000	15,000
Unsecured Debt								
Revenue Bonds								
5.30% NPC Series 1995D due 2011	-	-	-	-	14,000	-	14,000	-
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	-
Senior Notes								
7.803% NVE Senior Notes due 2012	-	-	-	-	63,670	63,670	-	-
8.625% NVE Senior Notes due 2014	-	-	-	-	230,039	230,039	-	-
6.75% NVE Senior Notes due 2017	191,500	191,500	-	-	191,500	191,500	-	-
6.25% NVE Senior Notes due 2020	315,000	315,000	-	-	-	-	-	-
Obligations under capital leases	55,735	-	55,735	-	47,047	-	47,047	-
Unamortized bond premium and discount, net	2,611	1	(11,748)	14,358	4,333	483	(11,958)	15,808
Current maturities	(355,929)	-	(355,929)	-	(134,474)	-	(119,474)	(15,000)
Total Long-Term Debt	$4,924,109	$506,501	$3,221,833	$1,195,775	$5,303,357	$485,692	$3,535,440	$1,282,225

Maturities of Long-Term Debt

As of December 31, 2010, NPC's, SPPC's and NVE'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):

	NVE Consolidated	NVE Holding Co.	NPC	SPPC
2011[(1)]	$ 354,465	$ -	$ 354,465	$ -
2012	134,822	-	134,822	-
2013	270,405	-	5,405	265,000
2014	128,513	-	128,513	-
2015	251,039	-	251,039	-
	1,139,244	-	874,244	265,000
Thereafter	4,138,183	506,500	2,715,266	916,417
	5,277,427	506,500	3,589,510	1,181,417
Unamortized Premium (Discount) Amount	2,611	1	(11,748)	14,358
Total	$5,280,038	$506,501	$3,577,762	$1,195,775

(1) Amounts may differ from current portion of long-term debt as reported on the consolidated balance sheet due to the timing difference of payments and the change in obligation.

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.

Lease Commitments

- In 1984, NPC entered into a 30-year capital lease for its Pearson Building with five-year renewal options beginning in year 2015. In February 2010, NPC amended this capital lease agreement to include the lease of the adjoining parking lot and to exercise, three of the five-year renewal options beginning in year 2015. There remain two additional renewal options which could extend the lease an additional ten years.
- 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.
- In 2007, NPC entered into a 20-year lease, with three 10-year renewal options, to occupy land and building for its Beltway Complex, and operations center in southern Nevada. As required by the Lease Topic of the FASC, NPC accounts for the building portion of the lease as a capital lease and the land portion of the lease as an operating lease. NPC transferred operations to the facilities in June 2009.
- In 2007, the Utilities entered into Master leasing agreements of which various pieces of equipment qualify as capital leases. The remaining equipment is treated as operating leases. Lease terms average seven years under the master lease agreement.

Future cash payments for these capital leases, combined, as of December 31, 2010, were as follows (dollars in thousands):

2011	$ 9,976
2012	9,828
2013	9,845
2014	7,435
2015	4,831
Thereafter	66,030
Total Minimum Lease Payments	$107,945
Less amounts representing interest	$ 52,210
Present Value of Net minimum lease payments	$ 55,735

Financing Transactions

NVE

6.25% Senior Notes

In November 2010, NVE issued and sold $315 million of its 6.25% Senior Notes, due 2020. Of the approximately $311 million in net proceeds, $307 million was used in December 2010 to redeem the approximately $230 million in the aggregate principal amount of 8.625% Senior Notes due 2014, and the approximately $63.7 million in the aggregate principal amount of 7.803% Senior Notes due 2012. The 8.625% Notes were redeemed at a purchase price of $1,028.75 for each $1,000 principal amount of the Notes, plus accrued interest. The 7.803% Notes were redeemed at a purchase price of $1,019.51 for each $1,000 principal amount of the Notes, plus accrued interest. The remaining net proceeds were used for general corporate purposes.

NPC

General and Refunding Mortgage Notes, Series X

In September 2010, NPC issued and sold $250 million of its 5.375% General and Refunding Mortgage Notes, Series X, due 2040. Of the approximately $247 million in net proceeds, $231 million was used in October 2010 to redeem (i) approximately $206 million in the aggregate principal amount of fixed rate unsecured tax-exempt local furnishing (''two-county'') bonds issued for NPC's benefit and (ii) approximately $20 million unsecured tax-exempt pollution control refunding revenue bonds issued for NPC's benefit. The remaining net proceeds of approximately $16 million were used to repay amounts outstanding under NPC's revolving credit facility.

$600 Million Revolving Credit Facility

In April 2010, NPC terminated its $589 million secured revolving credit facility which would have expired in November 2010 and replaced it with a $600 million secured revolving credit facility, maturing in April 2013. The fees on the $600 million revolving credit facility for the unused portion and on the amounts borrowed have increased from the prior facility reflecting current market conditions. The Administrative Agent for the facility remains Wells Fargo Bank, N.A. The rate for outstanding loans under the revolving credit facility will be at either an applicable base rate (defined as the highest of the Prime

Rate, the Federal Funds Rate plus ½ of 1.0% and the LIBOR Base Rate plus 1.0%) plus a margin, or a LIBOR rate plus a margin. The margin varies based upon NPC's credit rating by S&P and Moody's. Currently, NPC's applicable base rate margin is 1.25% and the LIBOR rate margin is 2.25%. The rate for outstanding letters of credit will be at the LIBOR rate margin plus a fee for the issuing bank.

The $600 million revolving credit facility contains a provision which reduces the availability under the credit facility by the negative mark-to-market exposure for hedging transactions with credit facility lenders or their energy trading affiliates. The reduction in availability limits the amount that NPC can borrow or use for letters of credit and would require that NPC prepay any amount in excess of that limitation. The amount of the reduction is calculated by NPC on a monthly basis, and after calculating such reduction, the NPC Credit Agreement provides that the reduction in availability under the revolving credit facility to NPC shall in no event exceed 50% of the total commitments then in effect under the revolving credit facility. The calculation of NPC's negative mark-to-market exposure as of November 30, 2010 was approximately $28.3 million, which amount was in effect for borrowings under the credit facility during the month of December 2010.

The NPC Credit Agreement contains one financial maintenance covenant that 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. In the event that NPC did not meet the financial maintenance covenant or there is a different event of default, the NPC Credit Agreement would restrict dividends to NVE. Moreover, so long as NPC's senior secured debt remains rated investment grade by S&P and Moody's (in each case, with a stable or better outlook), a representation concerning no material adverse change in NPC's business, assets, property or financial condition would not be a condition to the availability of credit under the facility. In the event that NPC's senior secured debt rating were rated below investment grade by either S&P or Moody's, or investment grade by either S&P or Moody's but with a negative outlook, a representation concerning no material adverse change in NPC's business, assets, property or financial condition would be a condition to borrowing under the revolving credit facility.

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*.

Redemption of Clark County, Nevada Industrial Development Revenue Bonds, Series 1997A

In November 2009, NPC provided a notice of redemption to the holders of all of the approximately $52.3 million aggregate principal amount of Clark County, Nevada Industrial Development Revenue Bonds, Series 1997A. The notes were redeemed in December 2009, at 100% of the stated principal amount plus accrued interest to the date of redemption. NPC redeemed these notes with the use of its revolving credit facility.

Maturity of Clark County Nevada Pollution Control Revenue Bonds, Series 2000B

In October 2009 the Clark County Nevada Pollution Control Revenue Bonds, Series 2000B, in the aggregate principal amount of $15 million, matured. In July 2008, these securities were converted from auction rate securities to variable rate demand notes. NPC purchased 100% of the bonds at that time, and remained the sole holder of these bonds until the maturity date. NPC financed the maturity with available cash.

General and Refunding Mortgage Notes, Series V

In March 2009, NPC issued and sold $500 million of its 7.125% General and Refunding Mortgage Notes, Series V due 2019. The net proceeds of the issuance were used to repay approximately $404 million of amounts outstanding under NPC's approximate $589 million revolving credit facility, and for general corporate purposes.

General and Refunding Mortgage Notes, Series U

In January 2009, NPC issued and sold $125 million of its 7.375% General and Refunding Mortgage Notes, Series U due 2014. The net proceeds of the issuance were used to repay approximately $124 million of amounts outstanding under NPC's revolving credit facility.

SPPC

Redemption of General and Refunding Mortgage Notes, Series H

In November 2010, SPPC provided a notice of redemption to the holders of its 6.25% General and Refunding Mortgage Notes, Series H, due 2012, in an aggregate principal amount of $100 million. The notes were redeemed in December 2010 at a purchase price of $1,069.61 for each $1,000 principal amount of the Notes, plus accrued interest. The redemption was funded predominantly with available cash on hand, with the balance being funded with a draw on its bank revolving credit facility.

$250 Million Revolving Credit Facility

In April 2010, SPPC terminated its $332 million secured revolving credit facility which would have expired in November 2010 and replaced it with a $250 million secured revolving credit facility, maturing in April 2013. The fees on the $250 million revolving credit facility for the unused portion and on the amounts borrowed have increased from the prior facility reflecting current market conditions. The Administrative Agent for the facility is Bank of America, N.A. The rate for outstanding loans under the revolving credit facility will be at either an applicable base rate (defined as the highest of the Prime Rate, the Federal Funds Rate plus ½ of 1.0% and the LIBOR Base Rate plus 1.0%) plus a margin, or a LIBOR rate plus a margin. The margin varies based upon SPPC's credit rating by S&P and Moody's. Currently, SPPC's applicable base rate margin is 1.25% and the LIBOR rate margin is 2.25%. The rate for outstanding letters of credit will be at the LIBOR rate margin plus a fee for the issuing bank.

The $250 million revolving credit facility contains a provision which reduces the availability under the credit facility by the negative mark-to-market exposure for hedging transactions with credit facility lenders or their energy trading affiliates. The reduction in availability limits the amount that SPPC can borrow or use for letters of credit and would require that SPPC prepay any amount in excess of that limitation. The amount of the reduction is calculated by SPPC on a monthly basis, and after calculating such reduction, the SPPC Credit Agreement provides that the reduction in availability under the revolving credit facility to SPPC shall in no event exceed 50% of the total commitments then in effect under the revolving credit facility. The calculation of SPPC's negative mark-to-market exposure as of November 30, 2010 was approximately $13.8 million, which amount was in effect for borrowings under the credit facility during the month of December 2010.

The SPPC Credit Agreement contains one financial maintenance covenant that requires SPPC 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. In the event that SPPC did not meet the financial maintenance covenant or there is a different event of default, the SPPC Credit Agreement would restrict dividends to NVE. Moreover, so long as SPPC's senior secured debt remains rated investment grade by S&P and Moody's (in each case, with a stable or better outlook), a representation concerning no material adverse change in SPPC's business, assets, property or financial condition would not be a condition to the availability of credit under the facility. In the event that SPPC's senior secured debt rating were rated below investment grade by either S&P or Moody's, or investment grade by either S&P or Moody's but with a negative outlook, a representation concerning no material adverse change in SPPC's business, assets, property or financial condition would be a condition to borrowing under the revolving credit facility.

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*.

Tender Offer for General and Refunding Mortgage Notes, Series P

In November 2009, SPPC provided notice of a cash tender offer to purchase up to $75 million aggregate principal amount of its 6.75% General and Refunding Mortgage Notes, Series P, due 2037. Those holders who tendered their Bonds by the early tender date of December 7, 2009 received a purchase price of $1,102.15 per $1,000 principal amount of Notes. Holders who validly tendered their Notes after the early tender date but before the tender expiration date of December 21, 2009 received a purchase price of $1,062.15 per $1,000 principal amount of Notes. In addition, holders received accrued and unpaid interest to, but not including the date of purchase. Approximately $73.3 million of the $325 million Series P Notes outstanding were validly tendered and accepted by SPPC. The tender offer was funded predominantly with cash on hand, with the balance being funded with borrowings under its revolving credit facility.

General and Refunding Mortgage Notes, Series M

On August 21, 2009, SPPC issued an additional $150 million in aggregate principal amount of its 6% General and Refunding Mortgage Notes, Series M, as part of the same series as the original Series M Notes issued in March 2006. Upon the issuance of these Notes, the aggregate principal amount of the Series M Notes outstanding is $450 million. The proceeds from the second issuance were used to repay amounts outstanding under SPPC's revolving credit facility.

Conversions

Conversion of Washoe County Water Facilities Refunding Revenue Bonds

In January 2009, SPPC converted the $40 million principal amount, Washoe County, Nevada Water Facilities Refunding Revenue Bonds Series 2007A bonds, due 2036 (the ''Water Bonds'') from auction rate securities to variable rate demand notes. The purpose of the conversion was to reduce interest costs and volatility associated with these bonds. SPPC purchased 100% of the Water Bonds on that date, with the use of its revolving credit facility and available cash, and will remain the sole holder of the Water Bonds until such time as SPPC determines to reoffer the Water Bonds to investors. These Water Bonds remain outstanding and have not been retired or cancelled. However, as SPPC is the sole holder of the Water Bonds, for financial reporting purposes the investment in the Water Bonds and the indebtedness is offset for presentation purposes.

NOTE 7. FAIR VALUE OF FINANCIAL INSTRUMENTS

The December 31, 2010, 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 NVE's consolidated long-term debt at December 31, 2010, is estimated to be $5.7 billion based on quoted market prices for the same or similar issues or on the current rates offered to NVE for debt of the same remaining maturities. The total fair value was estimated to be $5.7 billion as of December 31, 2009.

The total fair value of NPC's consolidated long-term debt at December 31, 2010, is estimated to be $3.9 billion 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 was estimated to be $3.8 billion at December 31, 2009.

The total fair value of SPPC's consolidated long-term debt at December 31, 2010, is estimated to be $1.3 billion 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 was estimated to be $1.3 billion as of December 31, 2009.

NOTE 8. DEBT COVENANT AND OTHER RESTRICTIONS

Dividends from Subsidiaries

Since NVE is a holding company, substantially all of its cash flow is provided by dividends paid to NVE by NPC and SPPC on their common stock, all of which is owned by NVE. In 2010, NPC and SPPC paid $74 million and $54 million in dividends, respectively, to NVE. At December 31, 2010, SPPC had a dividend payable to NVE for $54 million which was subsequently paid in January 2011.

On February 3, 2011, SPPC declared a $38 million dividend to NVE, to be paid in February 2011.

Since NPC and SPPC are public utilities, they are subject to regulation by state utility commissions, which impose limits on investment returns or otherwise may impact the amount of dividends that the Utilities may declare and pay.

Certain debt agreements entered into by NVE and the Utilities contain covenants which set restrictions on certain payments, including the amount of dividends they may declare and pay, and restrict the circumstances under which such dividends may be declared and paid.

Limits on Restricted Payments

NVE

Dividends are considered periodically by NVE's BOD and are subject to factors that ordinarily affect dividend policy, such as current and prospective earnings, current and prospective business conditions, regulatory factors, NVE's financial conditions and other matters within the discretion of the BOD, as well as dividend restrictions set forth in NVE's debt. The BOD will continue to review the factors described above on a periodic basis to determine if and when it is prudent to declare a dividend on NVE'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. In February, June and September 2010, NVE paid a cash dividend of $0.11 per share. In October 2010, the BOD increased the cash dividend to $0.12 per share, which was paid in December 2010. On February 3, 2011, NVE declared a cash dividend of $0.12 per share for common stock holders of record as of March 2011.

Certain NVE debt agreements contain covenants that limit the amount of restricted payments, including dividends that may be made by NVE. However, permitted payments, under these covenant calculations, exceed retained earnings, as such, retained earnings were free from any dividend restrictions as of December 31, 2010.

Dividend Restrictions Applicable to the Utilities

Since NVE is a holding company, substantially all of its cash flow is provided by dividends paid to NVE by NPC and SPPC on their common stock, all of which is owned by NVE. 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 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. As a result of the Utilities' credit rating on their senior secured debt at investment grade by S&P and Moody's, these restrictions are suspended and no longer in effect so long as the debt remains investment grade by both rating agencies. 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 NVE could be jeopardized.

Ability to Issue Debt

NVE

Certain debt of NVE (holding company) places restrictions on debt incurrence, liens and dividends, unless, at the time the debt is incurred, the ratio of cash flow to fixed charges for NVE's (consolidated) 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, 2010, NVE (consolidated) would be allowed to incur up to $1.9 billion of additional indebtedness, assuming an interest rate of 7%. The amount of additional indebtedness allowed would likely be impacted if there is a change in current market conditions or material change in our financial condition.

Notwithstanding this restriction, under the terms of the debt, NPC and SPPC would still be permitted to incur a combined total of up to $750 million in indebtedness and letters of credit under their respective revolving credit facilities. As of December 31, 2010, the combined total outstanding indebtedness and letters of credit under their respective revolving credit facilities was approximately $45.4 million not including any reductions for negative mark-to-market transactions. See NPC's and SPPC's *Ability to Issue Debt* sections for further discussion of the Utilities' limitations on ability to issue debt.

If the applicable series of 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 remain investment grade by both Moody's and S&P (see *Credit Ratings* above).

NPC

NPC's ability to issue debt is impacted by certain factors such as financing authority from the PUCN, financial covenants in its financing agreements and revolving credit facility agreements, and the terms of certain NVE debt. As of December 31, 2010, the most restrictive of the factors below is the PUCN authority. As such, NPC may issue up to $725 million in long-term debt, in addition to the use of its existing credit facilities. However, depending on NVE's or SPPC's issuance of long-term debt or the use of the Utilities' revolving credit facilities, the PUCN authority may not remain the most restrictive factor. The factors affecting NPC's ability to issue debt are further detailed below:

a. Financing authority from the PUCN - As of December 31, 2010, NPC has financing authority from the PUCN for the period ending December 31, 2013, consisting of authority (1) to issue additional long-term debt securities of up to $725 million; (2) to refinance up to approximately $672.5 million of long-term debt securities; and (3) ongoing authority to maintain a revolving credit facility of up to $1.3 billion.

b. Financial covenants within NPC's financing agreements - Under its $600 million revolving credit facility, NPC must 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. Based on December 31, 2010 financial statements, NPC was in compliance with this covenant and could incur up to $2.3 billion of additional indebtedness.

   All other financial covenants contained in NPC's financing agreements are suspended, as NPC's senior secured debt is rated investment grade. However, if NPC's senior secured debt ratings fall below investment grade by either Moody's or S&P, NPC would again be subject to the limitations under these additional covenants; and

c. Financial covenants within NVE's financing agreements - As discussed in NVE's *Ability to Issue Debt*, NPC is also subject to NVE's cap on additional consolidated indebtedness of $1.9 billion.

Ability to Issue General and Refunding Mortgage Securities

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 NPC's General and Refunding Mortgage Indenture (''Indenture'').

The Indenture creates a lien on substantially all of NPC's properties in Nevada. As of December 31, 2010, $4.2 billion of NPC's General and Refunding Mortgage Securities were outstanding. NPC had the capacity to issue $706.6 million of additional General and Refunding Mortgage Securities as of December 31, 2010. 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.

Property additions include plant-in-service and specific assets in CWIP. The amount of bond capacity listed above does not include eligible property in CWIP.

NPC also has the ability to release property from the lien of the mortgage indenture on the basis of net property additions, cash and/or retired bonds. To the extent NPC releases property from the lien of NPC's Indenture, it will reduce the amount of securities issuable under the Indenture.

SPPC

SPPC's ability to issue debt is impacted by certain factors such as financing authority from the PUCN, financial covenants in its financing agreements and its revolving credit facility agreement, and the terms of certain NVE debt. As of December 31, 2010, the most restrictive of the factors below is the PUCN authority. Based on this restriction, SPPC may issue up to $350 million of long-term debt securities, and maintain a credit facility of up to $600 million. However, depending on NVE's or NPC's issuance of long-term debt or the use of the Utilities' revolving credit facilities, the PUCN authority may not remain the most restrictive factor. The factors affecting SPPC's ability to issue debt are further detailed below:

a. Financing authority from the PUCN - As of December 31, 2010, SPPC has financing authority from the PUCN for the period ending December 31, 2012, consisting of authority (1) to issue additional long-term debt securities of up to $350 million; (2) to refinance approximately $348 million of long-term debt securities; and (3) ongoing authority to maintain a revolving credit facility of up to $600 million.

b. Financial covenants within SPPC's financing agreements - Under SPPC's $250 million revolving credit facility, the Utility must 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. Based on December 31, 2010 financial statements, SPPC was in compliance with this covenant and could incur up to $857 million of additional indebtedness.

All other financial covenants contained in SPPC's financing agreements are suspended, as SPPC's senior secured debt is rated investment grade. However, if SPPC's senior secured debt ratings fall below investment grade by either Moody's or S&P, SPPC would again be subject to the limitations under these additional covenants.

c. Financial covenants within NVE's financing agreements - As discussed in NVE's *Ability to Issue Debt*, SPPC is also subject to NVE's cap on additional consolidated indebtedness of $1.9 billion.

Ability to Issue General and Refunding Mortgage Securities

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 SPPC's General and Refunding Mortgage Indenture (''Indenture'').

The Indenture creates a lien on substantially all of SPPC's properties in Nevada. As of December 31, 2010, $1.5 billion of SPPC's General and Refunding Mortgage Securities were outstanding. SPPC had the capacity to issue $860.1 million of additional General and Refunding Mortgage Securities as of December 31, 2010. However, as a result of the sale of the California assets, as discussed in Note 16, *Assets Held for Sale*, SPPC's capacity to issue General and Refunding Mortgage Securities as of January 1, 2011, was reduced to $725.1 million. 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.

Property additions include plant in service and specific assets in CWIP. The amount of bond capacity listed above does not include eligible property in CWIP.

SPPC also has the ability to release property from the lien of the mortgage indenture on the basis of net property additions, cash and/or retired bonds. To the extent SPPC releases property from the lien of SPPC's Indenture, it will reduce the amount of securities issuable under the Indenture.

NOTE 9. DERIVATIVES AND HEDGING ACTIVITIES

NVE, NPC and SPPC apply the accounting guidance as required by the Derivatives and Hedging Topic of the FASC. The accounting guidance for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities, 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. The accounting guidance for derivative instruments also provides a scope exception for commodity 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 purchases and normal sales are accounted for under deferred energy accounting and not recorded on the consolidated balance sheets of NVE and the Utilities at fair value.

Commodity Risk

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. NVE 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 sale of power and the procurement and sale 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 assist the Utilities to reduce the risks associated with volatile electricity and natural gas markets.

Interest Rate Risk

In August 2009, NPC entered into two interest rate swap agreements which terminate in 2011, for an aggregated notional amount of $350 million associated with its $350 million 8.25% General and Refunding Mortgage Notes, Series A, due 2011. The interest rate swaps manage the existing fixed rate interest rate exposure with a variable interest rate in order to lower overall borrowing costs. As allowed by the Regulated Operations Topic of the FASC, as of December 31, 2010, the fair value of the interest rate swaps were recorded as a risk management asset with the corresponding offset recorded as a risk management regulatory liability and are included in the fair value table below.

Determination of Fair Value

As required by the Fair Value Measurements and Disclosure Topic of the FASC, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Risk management assets and liabilities in the recurring fair value measures table below include over-the-counter forwards, swaps, options and interest rate swaps. Total risk management assets or liabilities in the fair value table below do not include option premiums on commodity contracts which are not considered derivatives. Option premiums upon settlement are recorded in fuel and purchased power and are subsequently requested for recovery through the deferred energy mechanism. Option premium amounts included in risk management assets or liabilities on the balance sheets for NVE, NPC and SPPC were as follows (dollars in millions):

	2010			2009		
	NVE	NPC	SPPC	NVE	NPC	SPPC
Option Premiums						
Assets						
Current	$ 1.9	$ 1.4	$0.5	$11.9	$ 9.2	$2.7
Non-Current	-	-	-	1.9	1.4	0.5
Total Assets	$ 1.9	$ 1.4	$0.5	$13.8	$10.6	$3.2
Liabilities						
Current	$(0.4)	$(0.4)	$ -	$ -	$ -	$ -
Total Liabilities	$(0.4)	$(0.4)	$ -	$ -	$ -	$ -

Forwards and swaps are valued using a market approach that uses quoted forward commodity prices for similar assets and liabilities, which incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. Options are valued based on an income approach using an option pricing model that includes various inputs, such as forward commodity prices, interest rate yield curves and option volatility rates. Interest rate swaps are valued using a financial model which utilizes observable inputs for similar instruments based primarily on market price curves. The determination of the fair value for derivative instruments not only includes counterparty risk, but also the impact of NVE and the Utilities' nonperformance risk on their liabilities, which as of December 31, 2010, had an immaterial impact to the fair value of their derivative instruments.

The following table shows the fair value of the open derivative positions recorded on the consolidated balance sheets as of December 31, of NVE, NPC and SPPC and the related regulatory assets and/or liabilities that did not meet the normal purchase and normal sales exception criteria as required by the Derivatives and Hedging Topic of the FASC. Due to regulatory accounting treatment under which the Utilities operate, regulatory assets and liabilities are established to the extent that 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 derivative transactions until the period of settlement as of December 31 (dollars in millions):

	2010			2009		
	Level 2			Level 2		
	NVE	NPC	SPPC	NVE	NPC	SPPC
Derivative Contracts						
Risk management assets - current[1]	$ 2.1	$ 2.1	$ -	$ 15.7	$ 12.7	$ 3.0
Risk management assets - noncurrent	-	-	-	4.8	4.2	0.6
Total risk management assets	2.1	2.1	-	20.5	16.9	3.6
Risk management liabilities - current	32.9	22.4	10.5	66.9	39.1	27.8
Risk management liabilities - noncurrent	-	-	-	2.2	1.1	1.1
Total risk management liabilities	32.9	22.4	10.5	69.1	40.2	28.9
Risk management regulatory assets/liabilities - net[2]	$(30.8)	$(20.3)	$(10.5)	$(48.6)	$(23.3)	$(25.3)

(1) Risk management assets - current includes a $ 2.1 million cumulative gain for interest rate swaps with the offset recorded as a risk management regulatory liability above.

(2) When amount is negative it represents a risk management regulatory asset, when positive it represents a risk management regulatory liability. For the year ended December 31, 2010, NVE, NPC and SPPC would have recorded gains of $17.8 million, $3.0 million, and $14.8 million, respectively; however, as permitted by the Regulated Operations Topic of the FASC, NVE and the Utilities deferred these gains, which are included in the risk management regulatory asset amounts above.

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 their counterparties and the changes in market prices. Risk management assets and liabilities decreased as of December 31, 2010, as compared to December 31, 2009, primarily as a result of reduction in hedging transactions and the settlement of derivative contracts.

The following table shows the commodity volume for open derivative contracts related to natural gas contracts (amounts in millions):

	2010 Commodity Volume (MMBTU)			2009 Commodity Volume (MMBTU)		
	NVE	NPC	SPPC	NVE	NPC	SPPC
Commodity volume assets - current	-	-	-	47.1	40.7	6.4
Commodity volume assets - noncurrent	-	-	-	10.3	7.6	2.7
Total commodity volume of assets(1)	-	-	-	57.4	48.3	9.1
Commodity volume liabilities - current	18.1	12.9	5.2	51.7	32.7	19.0
Commodity volume liabilities - noncurrent	-	-	-	7.8	5.3	2.5
Total commodity volume of liabilities(1)	18.1	12.9	5.2	59.5	38.0	21.5

(1) The change in commodity volumes of assets and liabilities at December 31, 2010, as compared to December 31, 2009, is primarily due to the reduction in hedging transactions and the settlement of derivative contracts.

NOTE 10. INCOME TAXES (BENEFITS)

The following reflects the composition of taxes on income from continuing operations for the years ended December 31 (dollars in thousands):

	2010			2009			2008		
	NVE	NPC	SPPC	NVE	NPC	SPPC	NVE	NPC	SPPC
Current and other									
Federal	$ (15,354)	$ (886)	$ 1,081	$ (34,072)	$(34,318)	$ (488)	$44,647	$27,038	$13,663
State	957	22	935	12	-	12	12	-	12
Total current and other	(14,397)	(864)	2,016	(34,060)	(34,318)	(476)	44,659	27,038	13,675
Deferred									
Federal	132,716	93,591	41,973	114,053	97,878	34,335	54,341	45,830	26,087
State	(149)	711	(860)	548	256	292	693	378	315
Total deferred	132,567	94,302	41,113	114,601	98,134	34,627	55,034	46,208	26,402
Amortization of excess deferred taxes	(1,069)	(238)	(831)	(1,709)	(862)	(847)	(1,365)	(695)	(670)
Investment tax credits	(3,337)	(1,443)	(1,894)	(3,381)	(1,302)	(2,079)	(2,974)	(1,169)	(1,804)
Total provision for income taxes	$113,764	$91,757	$40,404	$ 75,451	$ 61,652	$31,225	$95,354	$71,382	$37,603

A reconciliation between income tax expense and the expected tax expense at the federal statutory rate for the years ended December 31 are as follows (dollars in thousands):

	2010			2009			2008		
	NVE	NPC	SPPC	NVE	NPC	SPPC	NVE	NPC	SPPC
Net income	$226,984	$185,943	$ 72,375	$182,936	$134,284	$ 73,086	$208,887	$151,431	$ 90,582
Total income tax expense	113,764	91,757	40,404	75,451	61,652	31,224	95,354	71,382	37,603
Pretax income	340,748	277,700	112,779	258,387	195,936	104,310	304,241	222,813	128,185
Statutory tax rate	35%	35%	35%	35%	35%	35%	35%	35%	35%
Federal income tax expense	119,262	97,195	39,473	90,435	68,578	36,509	106,484	77,985	44,865
Depreciation	4,090	1,813	2,277	(2,067)	1,695	(3,762)	1,132	1,209	(77)
AFUDC - equity	(9,839)	(8,830)	(1,009)	(8,496)	(7,359)	(1,137)	(13,454)	(9,071)	(4,383)
Investment tax credit amortization	(3,337)	(1,443)	(1,894)	(3,381)	(1,302)	(2,079)	(2,973)	(1,169)	(1,804)
Regulatory asset for goodwill	2,742	1,732	1,009	2,742	1,732	1,009	2,742	1,732	1,009
Research and development credit	(984)	(808)	(176)	(1,120)	(959)	(161)	(1,310)	(1,078)	(232)
Other - net	1,830	2,098	724	(2,662)	(733)	846	2,733	1,774	(1,775)
Provision for income taxes	$113,764	$ 91,757	$ 40,404	$ 75,451	$ 61,652	$ 31,225	$ 95,354	$ 71,382	$ 37,603
Effective tax rate	33.4%	33.0%	35.8%	29.2%	31.5%	29.9%	31.3%	32.0%	29.3%

The net deferred income tax liability consists of deferred income tax liabilities less related deferred income tax assets as of December 31 (dollars in thousands):

	2010			2009		
	NVE	NPC	SPPC	NVE	NPC	SPPC
Deferred tax assets						
Net operating loss and credit carryovers	$173,763	$ 82,529	$ 46,318	$208,118	$115,855	$ 41,282
Employee benefit plans	66,279	25,729	34,846	66,292	25,176	37,092
Customer advances	25,154	12,277	12,877	27,921	14,171	13,751
Gross-ups received on CIAC & customer advances	26,189	19,432	6,757	28,119	20,343	7,776
Deferred revenues	8,045	3,527	4,518	5,336	4,214	1,122
Deferred energy	70,499	18,804	51,695	18,060	-	40,752
Reserves	11,346	9,920	1,426	14,376	12,144	1,910
Other	27,843	19,155	7,867	33,198	21,294	9,782
Subtotal	409,118	191,373	166,304	401,420	213,197	153,467
Regulatory deferred tax assets						
Excess deferred income taxes	9,166	2,651	6,515	9,812	2,466	7,346
Unamortized investment tax credit	10,341	3,906	6,435	12,317	4,683	7,634
Subtotal	19,507	6,557	12,950	22,129	7,149	14,980
Total before valuation allowance	428,625	197,930	179,254	423,549	220,346	168,447
Valuation allowance	(1,455)	(1,455)	-	(1,430)	(1,430)	-
Total deferred tax assets after valuation allowance	$427,170	$196,475	$179,254	$422,119	$218,916	$168,447

	2010			2009		
	NVE	NPC	SPPC	NVE	NPC	SPPC
Deferred tax liabilities						
Excess of tax over book depreciation	$1,004,157	$ 661,672	$348,873	$ 881,282	$572,682	$308,600
Deferred Conservation Programs	78,755	58,627	20,128	59,387	49,059	10,328
Deferred energy	-	-	-	-	22,692	-
Regulatory assets	166,082	112,873	54,268	169,128	115,697	52,132
Other	36,707	21,092	15,101	35,907	21,915	13,478
Subtotal	1,285,701	854,264	438,370	1,145,704	782,045	384,538
Regulatory deferred tax liabilities						
Tax benefits flowed through to customers - property	116,850	86,284	30,567	117,212	82,958	34,254
Tax benefits flowed through to customers - goodwill	140,229	87,739	52,489	144,421	90,378	54,043
Subtotal	257,079	174,023	83,056	261,633	173,336	88,297
Total deferred tax liabilities	$1,542,780	$1,028,287	$521,426	$1,407,337	$955,381	$472,835
Net deferred income tax liability	$ 878,038	$ 664,346	$272,066	$ 745,714	$570,278	$231,071
Net regulatory deferred tax liability	237,572	167,466	70,106	239,504	166,187	73,317
Total net deferred tax liability	$1,115,610	$ 831,812	$342,172	$ 985,218	$736,465	$304,388

For balance sheet presentation, the regulatory tax asset is included in regulatory assets and the regulatory tax liability is included in regulatory liabilities. The regulatory tax asset balance 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 NVE. Offset against these amounts are future revenues to be refunded to customers (regulatory tax liabilities). The regulatory tax liability balance consists 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 similar to the accumulated deferred investment tax credit.

The following tables summarize as of December 31, 2010, the net operating loss and tax credit carryovers and associated carryover periods, and valuation allowance for amounts which NVE and the Utilities have determined that realization is uncertain (dollars in thousands):

	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
NVE Consolidated				
Federal net operating loss	$160,291	$ -	$160,291	2023-2030
Research and development credit	11,864	-	11,864	2023-2030
Arizona coal credits	1,608	1,455	153	2011-2015
Total	$173,763	$1,455	$172,308	

	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
NPC				
Federal net operating loss	$ 73,076	$ -	$ 73,076	2023-2030
Research and development credit	7,845	-	7,845	2023-2030
Arizona coal credits	1,608	1,455	153	2011-2015
Total	$ 82,529	$1,455	$ 81,074	

	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
SPPC				
Federal net operating loss	$ 42,299	$ -	$ 42,299	2023-2030
Research and development credit	4,019	-	4,019	2023-2030
Total	$ 46,318	$ -	$ 46,318	

At December 31, 2010, NVE has a gross Federal NOL carryover of $458.0 million, NPC of $208.8 million and SPPC of $120.9 million.

Considering all positive and negative evidence regarding the utilization of NVE's and the Utilities' deferred tax assets, it has been determined that NVE, NPC and SPPC are more-likely-than-not to realize all recorded deferred tax assets, except the Arizona coal credits on NVE and NPC. As such, these Arizona coal credits represent the only valuation allowance that has been recorded as of December 31, 2010 on NVE and NPC.

Accounting for Uncertainty in Income Taxes

Under Accounting for Uncertainty in Income Taxes, as reflected in the FASC, uncertain tax liabilities are all long-term and are included in the ''other deferred credits and liabilities'' line item on the balance sheet.

A summary of unrecognized tax benefits as of December 31 are as follows (dollars in thousands):

	2010			2009		
	NVE	NPC	SPPC	NVE	NPC	SPPC
Unrecognized tax benefits	$35,726	$25,490	$10,238	$38,229	$26,614	$10,509
Of the total, amounts related to tax positions that, if recognized, in future years would:						
Increase the effective tax rate	4,802	3,220	1,582	4,459	3,071	1,388

A reconciliation of the beginning and ending amount of unrecognized tax benefits as of December 31 are as follows (dollars in thousands):

	2010			2009		
	NVE	NPC	SPPC	NVE	NPC	SPPC
Balance at January 1	$38,229	$26,614	$10,509	$ 93,928	$ 48,487	$ 40,126
Increase in current period tax positions	317	102	214	3,325	2,787	500
Increase in prior period tax positions	118	65	53	11,773	9,246	2,527
Decrease in prior period tax positions	(2,938)	(1,291)	(538)	(70,797)	(33,906)	(32,644)
Balance at December 31	$35,726	$25,490	$10,238	$ 38,229	$ 26,614	$ 10,509

In December 2007, NVE and the Utilities filed a Form 3115, Application for Change in Accounting Method (''Application''), with the IRS requesting a change in accounting for deducting repair expenditures. In April 2009, NVE and the Utilities received notice from the IRS approving the Application. Accordingly, during the second quarter of 2009, NVE, NPC and SPPC recorded reductions to their unrecognized tax benefits for the repair positions taken in the prior period of approximately $64.4 million, $32.0 million and $32.2 million, respectively. Neither NVE nor the Utilities anticipate additional material changes in their uncertain tax position reserves in the next twelve months.

NVE and the Utilities classify interest and penalties related to income taxes as interest and other expense, respectively. NVE and the Utilities have not accrued interest or penalties as of December 31, 2010 and December 31, 2009. NVE and the Utilities do not expect unrecognized tax benefits to statutorily expire within the next twelve months.

NVE and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on NVE's and each subsidiaries' respective taxable income or loss and tax credits as if each subsidiary filed a separate return. The U.S. federal jurisdiction is the only ''significant'' tax jurisdiction for NVE. As of December 31, 2010, NVE's tax years 2005 through 2009 are subject to examination. As of December 31, 2010, NVE is no longer subject to examinations by U.S. federal, state, or local tax authorities for years before 2005, with few exceptions.

NOTE 11. RETIREMENT PLAN AND POST-RETIREMENT BENEFITS

NVE has a single employer defined benefit pension plan and other post-retirement plan covering substantially all employees of NVE and the Utilities. NVE allocates the unfunded liability and net periodic benefit costs for its pension benefit and other postretirement benefit plans to NPC and SPPC based upon the current, or in the case of the retirees, previous employment location. Certain grandfathered and union employees are covered under a benefit formula based on years of service and the employee's highest compensation for a period prior to retirement, while most employees are covered under a cash balance formula with vesting after three years of service. NVE also has other postretirement plans, including a defined contribution plan which provides medical and life insurance benefits for certain retired employees.

Plan Changes

Effective December 2010, under the terms of SPPC's new contract with IBEW No. 1245, as ratified in August 2010, the pension plan for most bargaining unit employees was changed from a traditional defined benefit pension plan to a defined benefit cash balance pension plan. Employees with combined age and service totaling 75 years or more were given the choice of staying with the current pension plan or switch to the new cash balance pension plan. This plan amendment, as indicated in the benefits obligations table below, reduced the 2010 projected benefit obligation for pension plans by approximately $10.4 million.

Additionally during 2010, benefits available to retired MPAT employees for health insurance coverage were amended. Retirees were given a choice between Health Reimbursement Accounts (HRA's) and Health Savings Accounts (HSA's). This plan, amendment as indicated in the benefit obligations table below, reduced the 2010 other post-retirement benefit obligation by approximately $0.7 million.

In September 2009, the post-retirement plan for existing retirees in the northern service area was amended to cap company contributions for retiree medical plans at 2009 levels in order to contain costs. As a result, NVE's obligation for the post-retirement medical plan was re-measured at September 30, 2009, resulting in a net reduction to the liability for other post-retirement benefits of $24.2 million, and a fourth quarter reduction in pension expense of approximately $1.0 million. The total change to other post-retirement benefit obligation at the December 31 re-measurement was $35.5 million and is noted in the table below. The annual impact of this change is estimated to be $4.0 million.

During 2009, in an effort to reduce costs, NVE implemented severance programs, as discussed in Note 17, *Severance Programs*, of the Notes to Financial Statements. Under the terms of the program, employees close to retirement age were offered special enhancements to bridge their pension and post-retirement benefits. As indicated in the table below, NVE recognized expense of $0.3 million for pension benefits and $2.8 million for other post-retirement benefits in 2009, under the special termination provisions of the Compensation Nonretirement Post-employment Benefits Topic of the FASC.

NVE also has a non-qualified Supplemental Executive Retirement Plan and a Restoration Plan for executives. NVE contributed $26.5 million to establish a rabbi trust primarily for these plans in 2009. Assets held in the trust for these non-contributory defined benefit plans consist of a variety of marketable securities and life insurance policies, none of which is NVE stock. At December 31, 2010, trust assets were $29.3 million and are reflected in NVE's consolidated balance sheet within ''Investments and other property, net''. NVE's obligation under these supplemental and restoration plans is included in ''Accrued retirement benefits'' in NVE's consolidated balance sheet, and amounted to $26.8 million at December 31, 2010. NVE is not required to make contributions to the plans.

Plan Obligations, Plan Assets and Funded Status as of December 31, 2010 and 2009

The following tables provide a reconciliation of benefit obligations, plan assets and the funded status of the plans. These reconciliations are based on a December 31 measurement date (dollars in thousands):

	Pension Benefits		Other Post-Retirement Benefits	
	2010	**2009**	**2010**	**2009**
Change in Benefit Obligations				
Benefit obligation, January 1	$ 757,748	$ 727,472	$ 154,287	$ 176,059
Service cost	18,910	18,838	2,466	2,421
Interest cost	42,872	44,145	8,736	10,072
Plan participants' contributions	-	-	1,924	1,677
Actuarial loss (gain)	54,890	7,054	9,166	7,617
Benefits paid	(58,002)	(40,077)	(12,495)	(10,953)
Plan amendments	(10,384)	-	(661)	(35,507)
Special termination benefits	-	316	-	2,818
Remeasurement adjustment	-	-	-	83
Benefit obligation, December 31	$ 806,034	$ 757,748	$ 163,423	$ 154,287
Change in Plan Assets				
Fair value of plan net assets, January 1	$ 670,794	$ 531,373	$ 93,298	$ 84,661
Actual return on plan assets	70,838	123,693	10,627	17,619
Employer contributions	41,698	55,805	294	294
Plan participants' contributions	-	-	1,924	1,677
Benefits paid	(53,390)	(40,077)	(12,495)	(10,953)
Fair value of plan net assets, December 31	$ 729,940	$ 670,794	$ 93,648	$ 93,298
Funded Status at December 31				
Funded status	$ (76,094)(1)	$ (86,954)(1)	$ (69,775)(1)	$ (60,989)(1)

(1) Amounts recognized as non-current liabilities (accrued retirement benefits) in the consolidated balance sheets as of December 31, 2010 and 2009.

The expected long-term rate of return on the pension and other post-retirement benefit plan assets is 6.75%, 7.10% and 8.00%, and 6.75% - 7.1%, 7.10% and 8.00%, respectively, in 2010, 2009 and 2008, respectively.

The following amounts would have been recognized in Accumulated Other Comprehensive Income, net of taxes, according to the provisions of the Compensation Retirement Benefits Topic of the FASC. Since NVE is able to recover expenses through rates, the amounts noted below will be recorded as Regulatory Assets for pension plans under the provisions of the Regulated Operations Topic of the FASC. Amounts recognized as of December 31 consist of (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
Net actuarial (gain)/loss	$ 263,015	$ 249,793	$ 71,650	$ 71,229
Prior service (credit)/cost	(24,343)	(15,753)	(37,149)	(40,377)
Accumulated other comprehensive income, pre-tax	238,672	234,040	34,501	30,852
Regulatory asset for pension plans	(232,717)	(234,040)	(34,501)	(30,852)
Accumulated other comprehensive income, pre-tax, at December 31	$ 5,955	$ -	$ -	$ -

The estimated amounts that will be amortized from the regulatory assets for pension plans and accumulated other comprehensive income into net periodic cost in 2011 are as follows (dollars in thousands):

	Pension Benefits	Other Postretirement Benefits
Actuarial (gain)/loss	$16,620	$ 4,333
Prior service (credit)/cost	$ (2,953)	$(3,947)

As of December 31, 2010 and 2009, the projected benefit obligation, accumulated benefit obligation, and fair value of plan net assets for pension plans with a projected benefit obligation in excess of plan net assets, and pension plans with an accumulated benefit obligation in excess of plan assets, were as follows (dollars in thousands):

	2010	2009
Projected benefit obligation, end of year	$806,034	$757,748
Accumulated benefit obligation, end of year	$772,846	$700,665
Fair value of plan net assets, end of year	$729,940	$670,794

Plan Assets

NVE'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. NVE contributed a total of $40.0 million in 2010 towards the pension plans.

NVE strives to maintain a reasonable and prudent amount of risk, and seeks to limit risk through diversification of assets. Also, NVE 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. NVE's investment guidelines prohibit investing the plan assets in real estate and NVE's stock.

NVE's long term strategy for the pension plan assets is to maximize risk adjusted returns while maintaining adequate liquidity to pay plan benefits. NVE is committed to prudent investments with ample diversification in terms of asset types, fund strategies, and investment managers. NVE maintained the target allocation of fixed income at 70% in order to minimize the earnings volatility of plan assets to match its liabilities. As such, NVE has elected to include an appropriate mix of indexed and actively managed investments to accomplish its strategy. The current allocation for pension plan net assets at December 31, 2010 is 65% fixed income, 19% domestic equity, 12% international equity, and 4% cash. The long-term target allocation for pension plan net assets is 70% fixed income, 20% U.S. equity, and 10% international equity. The fixed income investments are benchmarked against government and corporate credit bond indices. U.S. equity investments include large cap, mid-cap, and small-cap companies with an emphases towards small and mid-cap investments relative to the Russell 3000 Index. International equity is currently actively managed and includes investments in both established and emerging markets.

The current allocation for the other post-retirement benefit plan net assets at December 31, 2010 is 56% equity securities, 41% fixed income and 3% cash. The long term strategy for the other post-retirement benefit plan net assets is similar to the pension plan net assets strategy as described above. The target allocation for other post-retirement benefit assets is 60% equity and 40% fixed income. The equity is invested in indexed securities that track the S&P 500 Index. The fixed income is indexed and benchmarked against government and corporate credit bond indices.

The fair values of NVE's pension plan and other post-retirement benefits assets at December 31, 2010, within the fair value hierarchy as required by the Fair Value Measurements and Disclosures Topic of the FASC, by asset category are as follows (dollars in thousands):

Pension Plan Assets

Asset Category	Level 1	Level 2	Level 3	Total
Cash & Cash equivalents(1)	$ -	$ 29,698	$ -	$ 29,698
Equity:				
U.S. Equity Securities(2)	141,917	(23)	-	141,894
International Equity Securities	91,631	-	-	91,631
Fixed Income:				
U.S. Preferred Securities	59	-	-	59
International Preferred Securities	-	-	-	-
U.S. Fixed Income Securities(3)	111,866	326,642	-	438,508
International Fixed Income Securities	2,784	38,208	-	40,992
Other:				
U.S. Future Contracts	35	-	-	35
International Future Contracts	-	-	-	-
U.S. Convertible Securities	-	573	-	573
Total(4)	$348,292	$395,098	$ -	$743,390

Other Postretirement Benefit Assets

Asset Category	Level 1	Level 2	Level 3	Total
Cash & Cash equivalents[1]	$ -	$ 2,678	$ -	$ 2,678
Equity:				
U.S. Equity Securities[2]	50,235	-	-	50,235
International Equity Securities	2,397	-	-	2,397
Fixed Income:				
U.S. Preferred Securities	2	-	-	2
International Preferred Securities	-	-	-	-
U.S. Fixed Income Securities[3]	9,506	28,094	-	37,600
International Fixed Income Securities	73	999	-	1,072
Other:				
U.S. Future Contracts	1	-	-	1
International Future Contracts	-	-	-	-
U.S. Convertible Securities	-	15	-	15
Total[4]	$ 62,214	$ 31,786	$ -	$ 94,000

(1) Cash and cash equivalents consist of investment in commingled funds that are primarily comprised of money market holdings and marketable securities, U.S. Treasury bills and commercial paper valued and redeemable at cost.

(2) This category includes approximately 44% large-cap, 31% small and mid-cap, and 25% broad market domestic equity investments.

(3) Level 1 investments are comprised of fixed income securities that mainly invest in U.S. Treasury bonds. Level 2 investments consist of commingled funds that track the Barclays Capital Long Government and Corporate Credit Index.

(4) The fair value of NVE's pension plan and postretirement benefit assets does not reflect approximately $13.4 million and $0.4 million, respectively, in administrative trust net liabilities. As such, the fair value of the plans assets for both pension and postretirement benefits net of the $13.4 million and $0.4 million liability is approximately $729.9 million and $93.6 million, respectively, at December 31, 2010.

The actuarial assumptions used to determine December 31 benefit obligations and net periodic benefit costs were as follows:

	Benefit Obligations		Net Periodic Benefit Costs	
	2010	2009	2010	2009
Discount rate - pension	5.09%	5.80%	5.79%	6.09%
Discount rate - other benefits	5.20%	5.75%	5.75%	6.07%[1]
Rate of compensation increase	4.00%	4.50%	4.50%	4.50%
Expected long-term return on plan assets	N/A	N/A	6.75% - 7.1%	7.10%
Initial health care cost trend rate	8.00%	8.00%	8.00%	8.50%
Ultimate health care cost trend rate	4.75%	5.00%	5.00%	5.00%
Number of years to ultimate trend rate	8	7	7	6

(1) A discount rate of 5.37% was used for the September 30, 2009 remeasurement.

In selecting an assumed discount rate for fiscal year 2010 pension cost and for fiscal year-end 2010 disclosures, NVE's projected benefit payments were matched to the yield curve derived from a portfolio of over 300 high quality Aa bonds with yields within the 10th 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 (dollars in thousands):

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on the postretirement benefit obligation	$8,002	$(6,438)
Effect on total of service and interest cost components	$ 744	$ (589)

The expected ROR 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 ROR on reinvested assets.

There were no significant transactions between the plan and the employer or related parties during 2010, 2009, or 2008.

Net Periodic Cost

The components of net periodic pension and other postretirement benefit costs for NVE, NPC and SPPC for the years ended December 31, are presented below (dollars in thousands):

NVE

	Pension Benefits			Other Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
Service cost	$ 18,910	$ 18,837	$ 21,748	$ 2,466	$ 2,421	$ 2,562
Interest cost	42,872	44,145	42,818	8,736	10,072	10,732
Expected return on plan assets	(44,275)	(37,159)	(47,051)	(6,223)	(6,048)	(8,351)
Amortization of:						
Prior service (credit)/cost	(1,794)	(1,794)	(166)	(3,890)	(1,466)	(1,028)
Actuarial (gain)/loss	15,106	27,575	6,714	4,342	5,296	3,489
Settlement loss	-	-	-	-	-	338
Remeasurement adjustment	-	-	-	-	336	-
Total net benefit cost	$ 30,819	$ 51,604	$ 24,063	$ 5,431	$10,611	$ 7,742

The NVE total 2009 net periodic cost excludes special termination benefits of $0.3 million for pension and $2.8 million for other postretirement benefits, related to severance programs implemented in 2009. See Note 17, *Severance Programs*, for further discussion.

The average percentage of NVE net periodic costs capitalized during 2010, 2009 and 2008 was 34.0%, 36.6% and 37.1%, respectively.

NPC

	Pension Benefits			Other Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
Service cost	$ 9,567	$ 9,572	$ 12,798	$ 1,413	$ 1,325	$ 1,217
Interest cost	20,092	21,079	21,240	2,474	2,437	2,524
Expected return on plan assets	(21,447)	(17,847)	(22,554)	(2,270)	(2,067)	(2,702)
Amortization of:						
Prior service (credit)/cost	(1,733)	(1,733)	57	946	1,104	1,157
Actuarial (gain)/loss	7,056	13,192	3,321	1,199	1,272	808
Remeasurement adjustment	-	-	-	-	57	-
Total net benefit cost	$ 13,535	$ 24,263	$ 14,862	$ 3,762	$ 4,128	$ 3,004

The average percentage of NPC net periodic costs capitalized during 2010, 2009 and 2008 was 37.0%, 39.4% and 40.5%, respectively.

SPPC

	Pension Benefits			Other Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
Service cost	$ 8,016	$ 8,245	$ 7,998	$ 977	$ 1,028	$ 1,275
Interest cost	21,557	21,885	20,248	6,187	7,567	8,054
Expected return on plan assets	(21,723)	(18,321)	(23,270)	(3,844)	(3,894)	(5,512)
Amortization of:						
Prior service (credit)/cost	(104)	(104)	(137)	(4,851)	(2,586)	(2,201)
Actuarial (gain)/loss	7,876	13,701	3,085	3,109	3,990	2,633
Remeasurement adjustment	-	-	-	-	277	-
Total net benefit cost	$ 15,622	$ 25,406	$ 7,924	$ 1,578	$ 6,382	$ 4,249

The average percentage of SPPC net periodic costs capitalized during 2010, 2009 and 2008 was 34.2%, 36.4% and 36.5%, respectively.

The expected cash flows for the plans, including trust accounts, are as follows (dollars in thousands):

	Pension Benefit Payments	Other Postretirement Benefit Payments	Expected Federal Subsidy
2011	$ 50,661	$10,883	-
2012	52,911	10,754	-
2013	54,893	10,632	-
2014	56,713	10,754	-
2015	56,820	10,704	-
2016-2020	302,351	54,104	-

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.

In March 2010, the President signed into law comprehensive health care reform legislation under the Patient Protection and Affordable Care Act of 2010. One feature of this legislation is the elimination of the tax deductibility of employer health care costs for retiree prescription drug expenses that are reimbursed as part of the Medicare Part D federal subsidy. NVE has not participated in the subsidy program since 2008, and therefore does not expect any significant impact on its financial statements as a result of this legislation.

In June 2010, the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010 was signed into law. This legislation permits employers to choose between alternative amortization methods for shortfalls due to losses in asset market values. The legislation is designed to reduce contributions to defined benefit pension plans by allowing them to be spread over a longer period of time. NVE is currently evaluating the options and impact of this legislation, but does not believe it would need to avail itself of the benefits under this Act. NVE has not taken into account any possible impacts of this legislation in determining estimated future contributions.

NOTE 12. STOCK COMPENSATION PLANS

NVE'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 NVE'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, restricted stock units, performance units, performance shares, and other equity-based awards in cash. During 2010, NVE granted restricted stock units, performance units and performance shares under the long-term incentive plan. NVE also has an employee stock purchase plan which is available to all employees who meet minimum service requirements. The employees can choose to have amounts deducted from their paychecks which will be used to buy NVE's common stock at a discount. The plans are discussed in more detail below.

Total stock-based compensation expense for the following years was as follows (dollars in thousands):

	2010			
	Total	NVE	NPC	SPPC
Non-Qualified Stock Options	$ 71	$ 1	$ 51	$ 19
Performance Units and Performance Shares	7,145	54	4,966	2,125
Restricted Stock Units	902	10	610	282
Employee Stock Purchase Plan	376	28	134	214
Total Stock Compensation Expense	$8,494	$93	$5,761	$2,640

	2009			
	Total	NVE	NPC	SPPC
Non-Qualified Stock Options	$ 392	$ 5	$ 282	$ 105
Performance Units and Performance Shares	5,440	27	3,837	1,576
Restricted Stock Units	493	4	329	160
Employee Stock Purchase Plan	453	37	249	167
Total Stock Compensation Expense	$6,778	$73	$4,697	$2,008

	2008			
	Total	NVE	NPC	SPPC
Non-Qualified Stock Options	$1,006	$14	$ 701	$ 291
Performance Units and Performance Shares	2,468	30	1,657	781
Restricted Stock Units	294	5	211	78
Employee Stock Purchase Plan	288	24	149	115
Total Stock Compensation Expense	$4,056	$73	$2,718	$1,265

Non-Qualified Stock Options

Elected officers and key employees specifically designated by a committee of the BOD are eligible to be awarded non-qualified 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 be awarded; however, historically, dividend equivalents have not been granted. 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.

In 2010, 2009 and 2008, there were no grants of non-qualified stock options made to employees.

A summary of the status of NVE's non-qualified stock option plan as of December 31, 2010, 2009, and 2008, and changes during the year is presented below:

	2010		2009		2008	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at beginning of year	854,717	$15.40	1,278,557	$15.65	1,294,397	$15.77
Granted	-	$ -	-	$ -	-	$ -
Exercised	(44,730)	$ 8.83	(8,000)	$ 7.35	-	$ -
Forfeited	(81,299)	$18.18	(415,840)	$16.31	(15,840)	$24.93
Outstanding at end of year	728,688	$15.50	854,717	$15.40	1,278,557	$15.65
Options exercisable at year-end	728,688	$15.50	717,705	$14.84	956,431	$14.94
Intrinsic value of options exercised	$146,102	-	$ 21,120	-	-	-
Fair value of options vested	-	-	-	-	-	-

The fair value of each non-qualified 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 2007: Average Dividend Yield, 0%, Average Expected Volatility, 24.23%, Average Risk-Free Rate of Return, 4.41%, and Average Expected Life, 6 years.

The following table summarizes information about non-qualified stock options outstanding at December 31, 2010:

	Options Outstanding			Options Exercisable	
Year of Grant	Weighted Average Exercise Price	Number Outstanding at 12/31/10	Remaining Contractual Life	Weighted Average Exercise Price	Number Vested and Exercisable at 12/31/10
2001	$ 15.08	22,510	<1 years	$ 15.08	22,510
2002	$ 14.05	69,630	1 - 1.5 years	$ 14.05	69,630
2005	$ 10.10	98,950	4.2 - 4.4 years	$ 10.10	98,950
2006	$ 13.29	156,204	5.1 years	$ 13.29	156,204
2007	$ 18.25	381,394	6.1 - 6.8 years	$ 18.25	381,394
Weighted Average Remaining Contractual Life (years)	5.06			5.06	
Intrinsic Value	$509,568			$509,568	

Performance Shares

Performance Units

Performance Units, which were previously referred to as Performance Shares, vest at the end of a three-year period to the extent that specific stock price related performance targets are met, as determined by the Compensation Committee. If the established objectives are not met, the Performance Units are forfeited. Performance Units are typically paid in shares after vesting. Performance Units do not have any dividends, dividend equivalent rights or voting rights associated with them. Performance Units granted are measured based on NVE's total shareholder return relative to the average total shareholder return of companies listed in the S&P Super Composite Electric Utility Index throughout the three-year performance period. The Committee determined that the awards will vest according to the table shown below (a proportionate amount of shares will vest in the case of performance between the percentiles listed below):

Performance	Shares Vested
Below 35th Percentile	0% of grant
35th Percentile	50% of grant
50th Percentile	100% of grant
75th Percentile	150% of grant

Performance Shares

Performance Shares, which were previously referred to as Performance Based Restricted Shares or PBRS, vest at the end of a three-year period, based on average aggregate Corporate Goal performance under the Short Term Incentive Plan (STIP) and the average STIP payout over those three years. If the established objectives are not met, the Performance Shares are forfeited. Performance Shares are paid in shares, minus applicable taxes (based on the then fair market value of the shares) and do not entitle the recipient to dividends, dividend equivalent rights, or voting rights.

The following table summarizes Performance Units and Performance Shares activity for the following years:

	2010		2009		2008	
	Shares	Weighted-Average Grant Date Value	Shares	Weighted-Average Grant Date Value	Shares	Weighted-Average Grant Date Value
Nonvested shares at beginning of year	765,143	$11.73	389,681	$14.96	146,648	$14.41
Shares granted	750,918	$11.78	895,803	$10.90	518,121	$15.27
Shares vested	(665,956)	$12.08	(520,341)	$12.71	(268,057)	$14.13
Shares forfeited	(88,513)	$11.81	-	$ -	(7,031)	$14.82
Nonvested shares at end of year	761,592	$11.47	765,143	$11.73	389,681	$14.96
Fair value of shares issued	-	-	-	-	$3,813,555	-
Unrecognized compensation expense at end of year	$10,700,368	-	-	-	-	-
Weighted average remaining vesting period (years)	1.65	-	-	-	-	-

There were no payouts of performance units or performance shares in 2010 and 2009.

Compensation expense for performance units and performance shares is recognized ratably over the three-year vesting period. In the event the conditional criteria are not met, the awards are forfeited and the expense is reversed. Performance Units and Performance Shares are accounted for as liability awards and compensation costs are measured at each balance sheet date using NVE's closing stock price for that date. The closing trading price of NVE stock on December 31, 2010 was $14.05.

Restricted Stock Units

Elected officers and key employees specifically designated by a committee of the BOD are eligible to be awarded restricted stock units based on the guidelines in the plan. These grants vest over different periods as stated within the terms of each grant. The issuance of these shares is conditional upon the employee retaining employment with NVE throughout the entire vesting period.

	2010		2009		2008	
	Shares	Weighted-Average Grant Date Value	Shares	Weighted-Average Grant Date Value	Shares	Weighted-Average Grant Date Value
Nonvested shares at beginning of year	64,667	$11.41	32,750	$12.79	-	$ -
Shares granted	169,000	$11.65	66,000	$10.94	43,500	$13.04
Shares vested	(75,708)	$11.73	(33,083)	$11.85	(10,750)	$13.80
Shares forfeited	(8,180)	$11.14	(1,000)	$10.91	-	$ -
Nonvested shares at end of year	149,779	$11.53	64,667	$11.41	32,750	$12.79
Fair value of shares issued	-	-	-	-	-	-
Unrecognized compensation expense at end of year	$2,104,393	-	-	-	-	-
Weighted average remaining vesting period (years)	2.14	-	-	-	-	-

There were no payouts of restricted stock units in 2010, 2009 and 2008.

Compensation expense for restricted stock units is recognized ratably over the vesting period of each grant. If employment is terminated prior to the end of the vesting period, the award is forfeited and the expense is reversed. Restricted stock units are accounted for as liability awards and compensation costs are measured at each balance sheet date using NVE's closing stock price for that date. The closing trading price of NVE stock on December 31, 2010 was $14.05.

Employee Stock Purchase Plan

The employee stock purchase plan is available to all employees who meet minimum service requirements. In 2010, shareholders approved an additional 1,000,000 shares for distribution under the plan, bringing the total authorized up to an aggregate of 1,900,162 shares of common stock. 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 NVE's common stock. The option price discount is 15%, and the purchase price is the lesser of 85% of the market value on the offering commencement date, or 85% 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 NVE sold 147,457, 178,152 and 109,924 shares to employees in 2010, 2009 and 2008, respectively.

In accordance with the Stock Compensation Topic of the FASC, NVE recognized compensation expense in 2010, 2009 and 2008 related to the employee stock purchase plan. The expense for those years has been estimated for the employees' purchase rights on the date of grant, using the Black-Scholes option-pricing model. The following assumptions were used for 2010, 2009 and 2008, with an option life of six months:

Year	Average Dividend Yield	Average Expected Volatility	Average Risk-Free Rate of Return	Weighted-Average Fair Value
2010	2.79%	20.02%	0.22%	$2.55
2009	3.90%	28.89%	0.22%	$2.54
2008	0.00%	40.31%	1.22%	$2.56

NOTE 13. COMMITMENTS AND CONTINGENCIES

The Utilities enter into several purchase commitments for electric power, coal, natural gas and transportation, as well as, long-term service agreements, capital project commitments and operating leases. Detailed below are estimates of future commitments under these arrangements (dollars in thousands):

	NVE						
	2011	2012	2013	2014	2015	Thereafter	Total
Purchased Power	$ 425,819	$ 428,515	$438,834	$420,044	$433,230	$ 3,241,516	$ 5,387,958
Purchased Power-Not Commercially Operable	12,651	76,741	84,812	159,407	218,680	4,830,319	5,382,610
Coal & Natural Gas	520,039	207,830	55,479	52,590	50,763	147,253	1,033,954
Transportation	146,963	159,949	184,369	172,405	155,425	1,915,410	2,734,521
Long-Term Service Agreements	24,780	19,950	18,763	19,277	19,722	87,141	189,633
Capital Projects	236,099	134,887	43,139	-	-	-	414,125
Operating Leases	22,140	18,519	16,853	14,873	11,257	120,912	204,554
Total Commitments	$1,388,491	$1,046,391	$842,249	$838,596	$889,077	$10,342,551	$15,347,355

	NPC						
	2011	2012	2013	2014	2015	Thereafter	Total
Purchased Power	$ 327,200	$ 330,497	$328,093	$310,310	$315,565	$ 2,431,414	$ 4,043,079
Purchased Power-Not Commercially Operable	12,651	76,741	84,812	159,407	218,680	4,830,319	5,382,610
Coal & Natural Gas	362,046	149,013	38,461	34,406	35,220	147,253	766,399
Transportation	61,645	82,087	118,767	114,875	111,375	1,702,092	2,190,841
Long-Term Service Agreements	20,218	15,180	14,285	14,758	15,140	65,299	144,880
Capital Projects	227,969	66,964	42,986	-	-	-	337,919
Operating Leases	11,784	9,799	9,275	8,279	6,178	86,099	131,414
Total Commitments	$1,023,513	$ 730,281	$636,679	$642,035	$702,158	$ 9,262,476	$12,997,142

	SPPC						
	2011	2012	2013	2014	2015	Thereafter	Total
Purchased Power	$ 168,138	$ 168,226	$110,741	$109,734	$117,665	$ 810,102	$ 1,484,606
Purchased Power-Not Commercially Operable	-	-	-	-	-	-	-
Coal & Natural Gas	157,992	58,817	17,018	18,183	15,543	-	267,553
Transportation	85,319	77,861	65,602	57,530	44,050	213,318	543,680
Long-Term Service Agreements	4,562	4,770	4,478	4,519	4,582	21,842	44,753
Capital Projects	8,130	67,963	153	-	-	-	76,246
Operating Leases	7,911	6,275	5,134	4,149	2,635	34,813	60,917
Total Commitments	$ 432,052	$ 383,912	$203,126	$194,115	$184,475	$ 1,080,075	$ 2,477,755

Purchased Power

The Utilities have several contracts for long-term purchase of electric energy; the expiration of these contracts range from 2012 to 2039. While the Utilities are not required to make payment if power is not delivered under these contracts, estimated future payments are included in the tables above. Related party purchase power agreements have been eliminated from the NVE totals for the years 2011 and 2012.

Purchased Power - Not Commercially Operable

The Utilities entered into several contracts for long-term purchase of electric energy in which the facility remains under development. This represents the estimated payments under renewable energy power purchase contracts, which have been approved by the PUCN and are contingent upon the developers obtaining commercial operation and their ability to deliver power.

Coal & Natural Gas

The Utilities have several long-term contracts for the purchase of coal and natural gas; the expiration of these contracts range from 2011 to 2019.

Transportation

The Utilities have several long-term contracts for the transport of coal and natural gas. Also included in the transportation obligations is the TUA with GBT, of which NPC will be responsible for 95% and SPPC 5%. The TUA remains contingent upon final construction costs, and reaching commercial operation, which is expected in late 2012. The expiration of these transportation contracts range from 2011 to 2053.

Long-Term Service Agreements

The Utilities have long term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage.

Capital Projects

Capital projects at NPC include construction of the Harry Allen Generating Station and NV Energize and NPC's requirement to purchase the CDWR's share of the undepreciated cost of capital of Reid Gardner # 4 in 2013 (see Note 5, *Jointly Owned Properties*). Capital projects at SPPC include NV

Energize. Additionally, the Utilities have obligations regarding the construction of ON Line, of which NPC will be responsible for 95% and SPPC 5%.

Operating Leases

The Utilities have entered into various non-cancelable operating leases primarily for building, land and equipment. NPC's rent payments meeting the above described criteria for 2010, 2009 and 2008 were $13.6 million, $13.8 million and $10.8 million, respectively. SPPC's rent payments meeting the above described criteria for 2010, 2009 and 2008 were $14.0 million, $13.9 million and $12.1 million, respectively. Refer to Note 6, *Long-Term Debt, Lease Commitments*, for discussion regarding capital leases.

Environmental

NPC

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.

SPPC

North Valmy Generating Station

On June 22, 2009, SPPC received a request for information from the EPA - Region 9 under Section 114 of the Federal Clean Air Act requesting current and historical operations and capital project information for SPPC's North Valmy Generating Station located in Valmy, Nevada. SPPC co-owns and operates this coal-fired plant. Idaho Power Company owns the remaining 50%. The EPA's Section 114 information request does not allege any incidents of non-compliance at the plant, and there have been no other new enforcement-related proceedings that have been initiated by the EPA relating to the plant. SPPC completed its response to the EPA in December 2009 and will continue to monitor developments relating to this Section 114 request.

Litigation Contingencies

NPC and SPPC

Calpine Settlement

On September 19, 2007, NPC, SPPC and Calpine entered into a settlement agreement (the ''Settlement Agreement'') that resolved the issues and claims pertaining to three proofs of claim (Claim Nos. 5177, 5178 and 5179) filed by the Utilities against Calpine in Calpine's bankruptcy proceeding. The Settlement Agreement was approved by the United States Bankruptcy Court for the Southern District of New York on October 10, 2007, and by the FERC on December 28, 2007, in orders that are final and non-appealable.

Claim Nos. 5177 and 5179 filed by SPPC and NPC relate to complaints filed with FERC in December 2001 under Section 206 of the Federal Power Act seeking price reduction of forward wholesale power purchase contracts entered into prior to the FERC mandated price caps imposed in reaction to the Western U.S. energy crisis. The Settlement Agreement provided that, for Claim Nos. 5177 and 5179, SPPC and NPC would receive general unsecured claims in the Calpine bankruptcy proceeding of approximately $1.7 million and $1.3 million respectively, totaling $3 million. In February 2008, Calpine distributed shares of Calpine common stock to SPPC and NPC with respect to Claim Nos. 5177 and 5179, at the approximate value at the time of the distribution of approximately $1.3 million, and $1.1 million, respectively. The Utilities recognized these amounts as income for the year ended December 31, 2008.

Claim No. 5178 filed by NPC regarding Calpine's alleged breach of a 400 MW transmission service agreement (TSA) and a 2002 settlement agreement approved by the FERC. The Settlement Agreement provided that the claim shall be amended to reflect a general unsecured claim of $18 million against Calpine. NPC agreed to treat the distribution in respect to Claim No. 5178 as a prepayment for a new 400 MW TSA (''New TSA'') with a term commencing January 1, 2008 and ending approximately March 31, 2010, assuming no change in NPC's OATT service schedules and, in the event of any such changes, ending on the date the $18 million is depleted based on the applicable OATT service rate schedule. In February 2008, Calpine distributed shares of Calpine common stock to NPC having an approximate value at that time of $14.4 million, which will be recognized as transmission revenue over the term of the new TSA.

The distributions discussed above represent approximately 80% of the balance owed to NPC and SPPC under the three proofs of claims filed. Management cannot predict if the remaining 20% will be recovered due to the status of Calpine's bankruptcy proceedings, and as such has not recorded any further amounts as income. Subsequent to the distribution, NPC and SPPC sold all of their shares of Calpine common stock and recorded a gain of $1.8 million for the year ended December 31, 2008.

NPC

Lawsuit Against Natural Gas Providers

In April 2003, NVE (originally filed under the corporate name of SPR) and NPC filed a complaint in the U.S. District Court for the District of Nevada against several natural gas providers and traders seeking restitution of excessive prices paid for natural gas during the Western Energy Crisis. In July 2003, NVE and NPC filed a First Amended Complaint. A Second Amended Complaint was filed in June 2004, which named three different groups of defendants: (1) El Paso Corporation, El Paso Natural Gas Company, El Paso Merchant Energy, L.P., El Paso Merchant Energy Company, El Paso Tennessee Pipeline Company, El Paso Merchant Energy-Gas Company (''El Paso''); (2) Dynegy Marketing and Trade (''Dynegy''); and (3) Sempra Energy, Sempra Energy Trading Corporation, Southern California Gas Company, and San Diego Gas and Electric (''Sempra''). In December 2005, the District Court dismissed NVE and NPC's claims. NVE and NPC appealed this decision to the Ninth Circuit. Subsequently, NVE abandoned its appeal and the matter proceeded only with respect to NPC. In September 2007, the Ninth Circuit reversed the District Court's order. In November 2007, the Ninth Circuit denied the gas providers and traders' petition for rehearing. The Ninth Circuit remanded the case to the District Court for further proceedings. In January 2008, the defendants filed motions to dismiss, to which NPC responded in February 2008. In June 2008, NPC's claims survived the defendant's filed motions to dismiss and proceeded to discovery. In December 2008, NPC settled with Sempra for an immaterial amount. In June 2009, NPC reached settlement agreements with both Dynegy and El Paso. Any disputes between the parties have now been resolved and all claims have been dismissed.

Peabody Western Coal Company

NPC owns an 11% interest in the Navajo Generating Station which is located in Northern Arizona and is operated by Salt River. Other participants in the Navajo Generating Station are Arizona Public Service Company, Los Angeles Department of Water and Power and Tucson Electric Power Company (together with Salt River and NPC, the ''Navajo Joint Owners''). NPC also owns a 14% interest in the Mohave Generating Station which is located in Laughlin, Nevada and was operated by Southern California Edison (SCE) prior to the time it became non-operational on December 31, 2005.

Royalty Claim

In October 2004, the Navajo Generating Station's coal supplier, Peabody Western Coal Co. (Peabody WC), filed a complaint against the Navajo Joint Owners in Missouri State Court in St. Louis, alleging, among other things, a declaration that the Navajo Joint Owners are obligated to reimburse Peabody WC for any royalty, tax or other obligations arising out of a lawsuit that the Navajo Nation filed against Salt River, several Peabody Coal Company entities (including Peabody WC and collectively referred to as ''Peabody'') and SCE in June 1999 in the U.S. District Court for the District of Columbia (DC Lawsuit).

The Navajo Joint Owners were first served in the Missouri lawsuit in January 2005. The operating agent for the Navajo Generating Station, Salt River, defended the suit on behalf of the Navajo Joint Owners. In July 2008, the Court dismissed all counts against NPC, two without prejudice to their possible refiling at a later date. NPC is unable to predict whether any liability may arise from any of these matters, including from the ultimate outcome of the DC Lawsuit.

NPC is not a party to the DC Lawsuit although, as noted above, it is a participant in both the Navajo Generating Station and the Mohave Generating Station. The DC Lawsuit consists of various claims relating to the renegotiations of coal royalty and lease agreements and alleges, among other things, that the defendants obtained a favorable coal royalty rate for the lease agreements under which Peabody mines coal for both the Navajo Generating Station and the Mohave Generating Station by improperly influencing the outcome of a federal administrative process pursuant to which the royalty rate was to be adjusted. Initially, the DC Lawsuit sought $600 million in damages, treble damages and punitive damages of not less than $1 billion, and the ejection of defendants from all possessory interests and Navajo Tribal lands arising out of the primary coal lease. In July 2001, the U.S. District Court dismissed all claims against Salt River. In April 2010, the Navajo Nation amended their complaint; it no longer seeks treble damages. Factual discovery was completed in October 2010 and the parties are in settlement discussions. Management cannot predict the timing or outcome of a decision on this matter.

Retiree Health Care and Reclamation Claims

In addition to the above action before the Missouri State Court, Peabody further asserted in 1994 that the Navajo Joint Owners are liable under the CSA for Retiree Health Care Costs (RHCC) and Final Reclamation Costs (FRC), which Peabody WC is obligated to pay after the CSA expires and the Kayenta Mine closes. In 1996, Salt River and the Navajo Joint Owners filed a complaint in the Maricopa County (Arizona) Supreme Court seeking determinations that they are not liable for RHCC or FRC or, alternatively, that Peabody WC cannot recover RHCC and FRC until after the CSA ends. The case was dormant for several years, while Peabody WC pursued other RHCC and FRC claims arising out of similar coal contracts. Settlement discussions, led by Salt River on both the RHCC matter and the FRC claim reached final approvals with Peabody WC and the Navajo Joint Owners in July 2008 (Settlement Agreement and Mutual Release with Peabody). As of December 31, 2010, NPC has a $17.7 million liability recorded which management has assessed as the approximate amount to be paid, and recorded a corresponding other regulatory asset for such claims, which are currently being recovered through the deferred energy mechanism. The underlying lawsuit and arbitration have both been dismissed.

SPPC

Farad Dam

SPPC sold four hydro generating units, (10.3 MW total capacity), located in Nevada and California, for $8 million to TMWA in June 2001. The Farad Hydro (2.8 MW), has been out of service since the summer of 1996 due to a collapsed flume. The current estimate to rebuild the diversion dam, if management decides to proceed, is approximately $20 million. Under the terms of the contract with TMWA, SPPC is not entitled to receive the proceeds of sale relating to Farad unless and until it has reconstructed the Farad facility in a manner reasonably acceptable to TMWA or, alternatively SPPC assigns its casualty loss claim to TMWA and TMWA is reasonably satisfied regarding its rights with respect to such claim.

SPPC filed a claim with the insurers Hartford Steam Boiler Inspection and Insurance Co. and Zurich-American Insurance Company (collectively, the ''Insurers'') for the Farad flume and Farad 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 for Farad Dam. The case went to trial before the Court in April 2008. On September 30, 2008, the Court ruled that SPPC was not time barred from reconstructing Farad Dam, and has coverage for the full rebuild costs, subject to coverage sub-limits set forth in the insurance policies. The Court further ruled that SPPC is entitled to recover $4 million for costs incurred to date on Farad Dam and that SPPC shall have three years to rebuild the dam from the date of the Court's decision. In the event Farad Dam is not rebuilt, the Court determined SPPC would be entitled to actual cash value of approximately $1.3 million. SPPC has requested the court to reconsider the cash value to reflect rebuild costs and the Insurers opposed. The Insurers time to file an appeal on the Court's decision had been suspended pending the Court's determination on the cash value reconsideration. On July 10, 2009, the District Court declined SPPC's request to reconsider the cash value and further ordered that the three year period to replace the dam commences as of July 10th (''Order''). In early August 2009, SPPC appealed the District Court's $1.3 million cash value determination with the Ninth Circuit. Subsequently, in August 2009, the Insurers appealed the District Court's insurance coverage decision with the Ninth Circuit. The Ninth Circuit heard arguments on the appeal in November 2010 and further asked that the parties consider mediation settlement proceedings. In January 2011, the parties, including TMWA, agreed to engage in mediation settlement discussions. Mediation discussions are scheduled for early March, 2011.

Other Legal Matters

NVE 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.

NOTE 14. COMMON STOCK AND OTHER PAID-IN CAPITAL

Rights Agreement

In December 2005, the BOD voted to amend the Rights Agreement, dated as of February 2001 (as amended and restated, the ''Rights Agreement''), between NVE and Wells Fargo Bank Minnesota, N.A., to accelerate the final expiration date of the rights (''Rights'') issued there under to December 2005, and to terminate the Rights Agreement upon the expiration of the Rights. The BOD also adopted a policy governing future entry into a shareholder rights agreement or similar agreement (a ''shareholder rights plan''). NVE's policy is to seek shareholder approval prior to the adoption of a shareholder rights plan, unless the BOD, 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 NVE'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 it shall expire, unless ratified by shareholders, within one year of adoption.

Stock Ownership Plans

As of December 31, 2010, 11,749,161 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 2004 LTIP for officers and key employees allows for the issuance of NVE's common shares pursuant to awards that can be granted 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; restricted stock units; performance units; performance shares; bonus stock and cash.

NVE 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 NVE common stock. The purchase price of the stock is 85% of the market value on the offering date or the execution date, whichever is less.

Non-Employee Director Stock

The Non-Employee Director Stock Plan provides that a portion of NVE's outside directors' annual retainer be paid in NVE common stock. In addition, a retirement plan for outside directors was terminated prior to the merger between NVE and NPC in 1999 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 BOD, at the time the Director leaves the BOD.

The annual retainer for non-employee directors is $135,000, and the minimum amount to be paid in NVE stock is $75,000 per director. During 2010, 2009 and 2008, NVE granted the following total shares and related compensation to directors, respectively: 66,766, 96,796 and 85,412 shares, and $829,907, $969,582 and $1,014,818.

Common Stock Investment Plan

NVE offers a Common Stock Investment Plan (CSIP, or the Plan) for the purpose of promoting long-term ownership by providing a convenient method to purchase shares of our common stock and to reinvest cash dividends. New investors can purchase common stock directly from the company for as little as $250 for the first purchase. Existing shareholders can purchase additional shares up to once per month for as little as $50. Shares are purchased on the first business day of each month with the exception of months in which a dividend is paid where purchases are scheduled to be made on the date of the dividend payment. Through this Plan, shareholders can also choose to reinvest all or a portion (specified in increments of 10%) of cash dividends to purchase additional shares of common stock.

Dividends

	Dividends declared per share	
	2010	**2009**
First Quarter	$0.11	$0.10
Second Quarter	0.11	0.10
Third Quarter	0.11	0.10
Fourth Quarter	0.12	0.11

On February 3, 2011, NVE's BOD declared a quarterly cash dividend of $0.12 per share payable on March 16, 2011, to common shareholders of record on March 1, 2011.

During 2010 and 2009, NPC paid dividends to NVE of $74 million and $112.0 million, respectively. During 2010 and 2009, SPPC paid dividends to NVE of $54 million and $128.8 million, respectively. At December 31, 2010, SPPC had a dividend payable to NVE, which was subsequently paid in January 2011. On February 3, 2011, SPPC declared a $38 million dividend payable to NVE.

NOTE 15. EARNINGS PER SHARE (NVE)

The difference between basic EPS and diluted EPS is due to potentially dilutive common shares resulting from stock options, the non-employee director stock plan, the employee stock purchase plan, and the performance and restricted stock plans.

The following table outlines the calculation for earnings per share (EPS):

	Year Ended December 31,		
	2010	2009	2008
Basic EPS			
Numerator ($000)			
Net income	$ 226,984	$ 182,936	$ 208,887
Denominator			
Weighted-average number of common shares outstanding	235,048,347	234,542,292	234,031,750
Per Share Amounts			
Net income per share - basic	$ 0.97	$ 0.78	$ 0.89
Diluted EPS			
Numerator ($000)			
Net income	$ 226,984	$ 182,936	$ 208,887
Denominator(1)			
Weighted average number of shares outstanding before dilution	235,048,347	234,542,292	234,031,750
Stock options	34,590	27,596	39,556
Non-Employee Director stock plan	141,577	100,244	63,636
Employee stock purchase plan	5,909	7,331	4,615
Restricted Shares	78,920	12,389	1,842
Performance Shares	985,469	490,836	443,605
	236,294,812	235,180,688	234,585,004
Per Share Amounts			
Net income per share - diluted	$ 0.96	$ 0.78	$ 0.89

(1) The denominator does not include stock equivalents for options issued under the non-qualified stock option plan due to conversion prices being higher than market prices for all periods. Under this plan, an additional 701,658, 679,272 and 943,231 shares, respectively, would be included in each of these periods if the conditions for conversion were met.

NOTE 16. ASSETS HELD FOR SALE

Sale of California Electric Distribution and Generation Assets

On January 1, 2011, SPPC sold its California electric distribution and generation assets to CalPeco, CalPeco will do business as Liberty Energy-CalPeco. Cash proceeds from the sale were approximately $132 million, resulting in an immaterial after tax gain, which will be recorded in the first quarter of 2011. In connection with the sale of the assets, SPPC entered into a separate five year purchase power agreement to sell energy to CalPeco.

In accordance with FASB presentation accounting guidance for discontinued operations, ASC 205-10-20, the California asset sale met the ''assets held for sale'' criteria, but, did not meet the ''component-of-an-entity'' criteria. The California electric distribution and generation assets held for sale do not have cash flows that can be clearly distinguished operationally from the rest of the entity because they do not operate individually, but rather as a part of SPPC's whole operating system, which includes all of the electric distribution and generation assets owned by SPPC.

Below are the major classes of assets and liabilities held for sale and presented in the consolidated balance sheets as of December 31 (dollars in millions):

	2010	2009
Assets		
Utility Plant in Service	$196.8	$188.6
Less: Accumulated depreciation	55.8	55.4
Utility Plant in Service, net	141.0	133.2
CWIP	5.2	4.6
Other current assets	9.1	8.6
Deferred Charges	-	0.8
Assets Held for Sale	$155.3	$147.2
Liabilities		
Deferred Credits and Other Liabilities	$ 30.7	$ 25.7
Liabilities Held for Sale	$ 30.7	$ 25.7

Sale of Independence Lake

In May 2010, SPPC sold a lake and surrounding property located in the State of California, known as Independence Lake, for approximately $15 million. The gain on sale was approximately $14.7 million before taxes; however, approximately $7.1 million of the gain has been deferred as a regulatory liability and will be paid to SPPC's ratepayers over approximately three years.

NOTE 17. SEVERANCE PROGRAMS

In response to reduced load growth and reductions in capital construction, NVE and the Utilities conducted reviews of their current operating costs to align future operating and maintenance expenses with forecasted load growth. During 2009, NVE and the Utilities reduced their workforce by approximately 5% through a combination of voluntary and involuntary severance programs.

As a result of the severance programs, NPC and SPPC recorded other operating expense in 2010 of approximately $222 thousand and $864 thousand, respectively; and in 2009 NVE, NPC, and SPPC recorded other operating expense of approximately $197 thousand, $6.7 million, and $6.3 million, respectively, of severance costs primarily for their management, professional administrative and technical (MPAT) class of employees. See Note 11, *Pension and Other Post Retirement Benefits*, for additional details regarding severance costs.

NOTE 18. 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.

NVE

	2010 Quarter Ended			
	March	June	Revised September	December
Operating Revenues[1]	$714,489	$782,683	$1,128,039	$655,011
Operating Income as previously reported	$ 72,906	$124,730	$ 351,364	N/A
Terminated contracts[2]	N/A	N/A	$ (8,000)	N/A
Revised Operating Income	$ 72,906	$124,730	$ 343,364	$103,435
Net Income (Loss) as previously reported	$ (1,721)	$ 36,946	$ 182,746	N/A
Terminated contracts, net of taxes[2]	N/A	N/A	$ (5,200)	N/A
Revised Net Income (Loss)	$ (1,721)	$ 36,946	$ 177,546	$ 14,213
Net Income (Loss) per Share				
Basic as previously stated	$ (0.01)	$ 0.16	$ 0.78	N/A
Terminated contracts, net of taxes[2]	N/A	N/A	$ (0.02)	N/A
Revised Basic	$ (0.01)	$ 0.16	$ 0.76	$ 0.06
Diluted as previously stated	$ (0.01)	$ 0.16	$ 0.77	N/A
Terminated contracts, net of taxes[2]	N/A	N/A	$ (0.02)	N/A
Revised Diluted	$ (0.01)	$ 0.16	$ 0.75	$ 0.06

	2009 Quarter Ended			
	March	June	September	December
Operating Revenues[1]	$755,267	$838,641	$1,219,007	$772,883
Operating Income	$ 42,097	$ 94,299	$ 342,085	$ 85,602
Net Income (Loss)	$ (22,244)	$ 18,383	$ 182,646	$ 4,151
Net Income (Loss) per Share Basic & Diluted	$ (0.09)	$ 0.08	$ 0.78	$ 0.02

(1) As discussed in Note 1, *Significant Accounting Policies*, amounts for REPR are presented net. Revenues were reduced by approximately $2.5 million, $2.7 million and $3.5 million for the periods ending March 31, June 30 and September 30, 2010, respectively, which had no effect on operating income or net income. In 2009, REPR costs were not material and were included in operating expenses with a corresponding amount recorded to revenues and had no effect on net income.

(2) During the third quarter 2010, NPC terminated a long term service agreement for one of its generating stations. The termination payment was not material to the third quarter but would be material to the fourth quarter; therefore, management determined it more appropriate to revise third quarter 2010 for the termination payment.

(3) During the fourth quarter of 2009, NVE and the Utilities recorded expense related to severance programs of $13.2 million.

NPC

	2010 Quarter Ended			
	March	June	Revised September	December
Operating Revenues[1]	$425,799	$539,395	$870,950	$416,233
Operating Income as previously reported	$ 30,129	$ 93,670	$296,163	N/A
Terminated contracts[2]	N/A	N/A	$ (8,000)	N/A
Revised Operating Income	$ 30,129	$ 93,670	$288,163	$ 55,450
Net Income (Loss) as previously reported	$ (12,326)	$ 29,784	$164,128	N/A
Terminated contracts, net of taxes[2]	N/A	N/A	$ (5,200)	N/A
Revised Net Income (Loss)	$ (12,326)	$ 29,784	$158,928	$ 9,557

	2009 Quarter Ended			
	March	June	September	December
Operating Revenues[1]	$436,529	$575,769	$933,520	$ 477,559
Operating Income	$ (3,082)	$ 61,675	$292,900	$ 44,869
Net Income (Loss)	$ (35,151)	$ 12,501	$163,591	$ (6,657)[3]

(1) As discussed in Note 1, *Significant Accounting Policies*, amounts for REPR are presented net. Revenues were reduced by approximately $1.2 million, $1.4 million and $2.0 million for the periods ending March 31, June 30 and September 30, 2010, respectively, which had no effect on operating income or net income. In 2009, REPR costs were not material and were included in operating expenses with a corresponding amount recorded to revenues and had no effect on net income.

(2) During the third quarter 2010, NPC terminated a long-term maintenance contract. Adjustment to recognize $8 million settlement costs, net of $2.8 million tax savings.

(3) During the fourth quarter of 2009, NVE and the Utilities recorded expense related to severance programs of $6.7 million.

SPPC

	2010 Quarter Ended			
	March	June	September	December
Operating Revenues[1]	$288,682	$243,282	$257,084	$238,774
Operating Income	$ 43,404	$ 32,184	$ 56,223	$ 49,184
Net Income	$ 17,120	$ 11,315	$ 24,462	$ 19,478

	2009 Quarter Ended			
	March	June	September	December
Operating Revenues[1]	$318,731	$262,862	$285,479	$295,321
Operating Income	$ 45,701	$ 33,585	$ 49,850	$ 41,453
Net Income	$ 19,136	$ 14,804	$ 24,266	$ 14,879[2]

(1) As discussed in Note 1, *Significant Accounting Policies*, amounts for REPR are presented net. Revenues were reduced by approximately $1.3 million, $1.3 million and $1.5 million for the periods ending March 31, June 30 and September 30, 2010, respectively, which had no effect on operating income or net income. In 2009, REPR costs were not material and were included in operating expenses with a corresponding amount recorded to revenues and had no effect on net income.

(2) During the fourth quarter of 2009, NVE and the Utilities recorded expense related to severance programs of $6.3 million.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of disclosure controls and procedures.

NVE, NPC and SPPC management, under the supervision and with the participation of the company's Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of NVE, NPC and SPPC disclosure controls and procedures (as that term is defined in Rules 13a-15(e) or 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period, NVE, NPC and SPPC disclosure controls and procedures are effective.

(b) Reports on Internal Control Over Financial Reporting.

Management's Report on Internal Control Over Financial Reporting

NV Energy, Inc.

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

Although NVE 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.

NVE's management assessed the effectiveness of NVE's internal control over financial reporting as of December 31, 2010. In making this assessment, NVE 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, 2010, NVE's internal control over financial reporting is effective based on those criteria.

NVE's independent registered public accountants have issued an attestation report on NVE's internal control over financial reporting.

Nevada Power Company

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

Although NPC 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.

NPC's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010. In making this assessment, NPC 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, 2010, NPC's internal control over financial reporting is effective based on those criteria.

Sierra Pacific Power Company

The management of SPPC is responsible for establishing and maintaining adequate internal control over financial reporting. SPPC's internal control system was designed to provide reasonable assurance to the Company's management and BOD regarding the preparation and fair presentation of published financial statements.

Although SPPC 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.

SPPC's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010. In making this assessment, SPPC 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, 2010, SPPC's internal control over financial reporting is effective based on those criteria.

Attestation Report

This annual report does not include an attestation report of the independent registered public accountants regarding internal control over financial reporting of NPC and SPPC. The management reports of NPC and SPPC were not subject to attestation by the independent registered public accountants pursuant to the rules of the SEC that permit NPC and SPPC to provide only management's reports in their annual report.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
NV Energy, Inc.
Las Vegas, Nevada

We have audited the internal control over financial reporting of NV Energy, Inc. and subsidiaries (the ''Company'') as of December 31, 2010, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2010 of the Company and our report dated February 25, 2011 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP
Las Vegas, Nevada
February 25, 2011

(c) Changes in Internal Controls

None.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

DIRECTORS

The information required by this Item is incorporated by reference to the definitive proxy statement for our 2011 Annual Meeting of Stockholders to be filed with the SEC, other than the information regarding executive officers shown below, within 120 days after the end of our 2010 fiscal year (the ''2011 Proxy Statement'').

EXECUTIVE OFFICERS

The following are current executive officers of NVE, NPC and SPPC indicated and their ages as of December 31, 2010. There are no family relationships among them. Officers serve a term which extends to and expires at the annual meeting of the BOD or until a successor has been elected and qualified:

Michael W. Yackira, 59, President and Chief Executive Officer, NVE; President and Chief Executive Officer of NPC; Chief Executive Officer of SPPC

Mr. Yackira was elected to his current position as CEO of NVE effective August 2007. He was previously the Company's president and chief operating officer from February, 2007 until August, 2007. Prior to that, he served as executive vice president and chief financial officer from December 2003 to February 2007. Prior to that, he was Executive Vice President, Strategy and Policy, from January 2003 to December 2003. Previously, Mr. Yackira served as vice president and CFO of Mars Music, Inc. from 2001 to 2002. Prior to that, he was with Florida-based FPL Group, Inc. (now known as NextEra) from 1989 to 2000 where he held such positions as President of FPL Energy, Vice President, Finance and CFO of FPL Group and Senior Vice President of Market and Regulatory Services among other positions. Mr. Yackira also serves as a director of the Edison Electric Institute, the Nevada Development Authority, the Nevada Cancer Institute and the Council for a Better Nevada. Mr. Yackira serves on the board of trustees of UNLV Foundation and served as a director on United Way from 2007 to 2009. He further served as a director on the American Heart Association and as a Trustee for the Las Vegas Chamber of Commerce. Mr. Yackira holds a Bachelor of Science degree in Accounting from Lehman College, City University of New York. Mr. Yackira is a CPA. Mr. Yackira was elected a director of NVE, NPC and SPPC in February 2007.

Jeffrey L. Ceccarelli, 56, Senior Vice President, Energy Supply, NVE; President, SPPC

Mr. Ceccarelli was elected to his present position as Senior Vice President, Energy Supply on June 1, 2009. Prior to that, he served as Senior Vice President, Service Delivery & Operations since October 2004. From June 2000, he has held the position of President, SPPC. He previously held the position of Vice President, Distribution Services, New Business, in July 1999 for SPPC and NPC. A civil engineer, Mr. Ceccarelli has been with SPPC since 1972.

Roberto R. Denis, 61, Senior Vice President, Energy Delivery, NVE

Mr. Denis was elected to his present position of Senior Vice President, Energy Delivery on June 1, 2009 and holds the same position at NPC and SPPC. Prior to that he held the position of Senior Vice President, Energy Supply since October 2004. From August 2003 to October 2004 he held the position of Vice President, Energy Supply, for NPC and SPPC. From 2001 to 2003, he held the position of Vice President, Market & Regulatory Affairs, at FPL Energy, LLC., a subsidiary of FPL Group (now known as

NextEra). Prior to that, he held the position of Vice President of Market Services from 1999 to 2001 at FPL Energy, LLC.

Paul J. Kaleta, 55, Senior Vice President, General Counsel, Shared Services, and Secretary, NVE

Mr. Kaleta was elected to his present position in February 2006, and holds the same position at NPC and SPPC. Previously, he was General Counsel for Koch Industries, Inc. and various Koch subsidiaries from 1998 to 2005. Prior to that, he was Vice President and General Counsel of Niagara Mohawk Power Company for 8 years and, before that, in the private practice of law as an associate with Skadden, Arps, Slate, Meagher & Flom and as an associate and then equity member with Swidler Berlin, Chtd. (now Bingham McCutchen), both in Washington, D.C., for a total of 9 years. Mr. Kaleta serves as a Director of the United Way of Southern Nevada since June 2009. Mr. Kaleta also serves as a Director of I Have a Dream Foundation.

Dilek L. Samil, 55, Senior Vice President Finance, Chief Financial Officer and Treasurer, NVE

Ms. Samil was elected Senior Vice President Finance, Chief Financial Officer and Treasurer effective June 2010. Prior to joining NV Energy, she was President and Chief Operating Officer for CLECO Power LLC, after having been its Chief Financial Officer since 2001. She also has served as Vice President, Finance of FPL Energy (now known as NextEra), a leader in renewable energy development, and treasurer of FPL Group and Florida Power & Light Company.

Tony F. Sanchez, III, 44, Senior Vice President, Government and Community Strategy, NVE

Mr. Sanchez was elected to his current position effective August 1, 2007, and holds the same position at NPC and SPPC. Prior to joining NVE, Mr. Sanchez was a partner in the Nevada based law firm of Jones Vargas. Prior to that, Mr. Sanchez served as executive assistant to Nevada's then-Governor Bob Miller from 1998 to 1999. From 1995 to 1998, he held the position of assistant General Counsel for the PUCN. From 1992 to 1995, he worked as associate legislative counsel in Washington, D.C. handling energy and natural resource issues for Nevada's then-U.S. Senator Richard H. Bryan. He further currently serves on the boards of the Nevada Tax Payers Association, Nevada Partners, the Nevada Mining Association, the Clark County Public Education Foundation and the Nevada Partnership for Homeless Youth.

Robert E. Stewart, 62, Senior Vice President, Customer Relationship, NVE

Mr. Stewart was elected to his current position in August 9, 2009, and holds the same position at NPC and SPPC. From February 2008 to August 2009, he was the Vice President, Marketing for NVE. From January 1997 to February 2008, he worked as an independent consultant in several industries, including energy services and telecommunications. He was Vice President of Marketing for FPL Group, Inc. from June 1991 to November 1996. Prior to that, he worked at GTE for 19 years and was Vice President of Product Management at GTE Telephone Operations from June 1989 to June 1991. Mr. Stewart serves as Director of YMCA of Southern Nevada.

E. Kevin Bethel, 47, Vice President, Chief Accounting Officer, and Controller, NVE

Mr. Bethel joined NVE as Vice President and Chief Accounting Officer of NVE on November 2, 2007, effective December 10, 2007, and holds the same position at NPC and SPPC. He was subsequently elected Corporate Controller of NVE as well as Vice President, Chief Accounting Officer, and Controller of NPC and SPPC on February 8, 2008. Mr. Bethel served as Interim Chief Financial Officer and Treasurer of NVE and its subsidiaries from February 2010 through May 2010. Prior to joining NVE, Mr. Bethel served as Assistant Controller for American Electric Power, Inc. (AEP), in Columbus, Ohio where he held management positions in accounting from 2001 to 2007. From 2000 to 2001, he held a management position with CSW Energy until they merged with AEP. Before that, he held accounting management positions with The Williams Company in 1999, Central & South West Services from 1994 to 1999, and the Public Service Company of Oklahoma from 1991 to 1994. Mr. Bethel is a CPA.

Thomas R. Fair, 64, Vice President, Renewables

Mr. Fair was elected to his present position in February 2009, and holds the same position at NPC and SPPC. Previously, he was Executive, Renewable Energy from 2006 to 2009. Prior to that, he was Director, Environmental Services since 2004. Mr. Fair has held a number of executive positions in renewable energy development and environmental affairs with such companies as Florida-based FPL Energy (now knows as NextEra) and Niagara Mohawk.

Gary L. Lavey, 52, Vice President, Internal Audit and Chief Risk Officer, NVE

Mr. Lavey was appointed as Chief Risk Officer in May 2010. Mr. Lavey was elected as Vice President, Internal Audit of NVE in October 2008, effective January 1, 2009. He reports to the Audit Committee of the BOD. Prior to joining NVE, Mr. Lavey was vice president of Risk Management for CNG Financial (a privately held company) from 2006 to 2008. Prior to CNG, he held the position of Vice President of Global Risk Management for Cinergy Corporation (a publicly held company) from 1999 to 2006, and was President of their captive insurance company. Before that, he held risk management positions at Ameren Energy Inc. (a publicly held company) and LG&E Energy Marketing Inc. (a subsidiary of a publicly held company). Mr. Lavey is a CPA and began his career with PricewaterhouseCoopers.

Punam N. Mathur, 49, Vice President, Human Resources, NVE

Ms. Mathur was elected to her current position in April 2009. Prior to joining NVE, Ms. Mathur was Senior Vice President, Corporate Diversity and Community Affairs and a Corporate Officer of MGM MIRAGE, a gaming entertainment company, since 2005. She was Vice President of Corporate Diversity and Community Affairs of MGM MIRAGE from 2000 to 2005, and Director of Government Affairs and Community Relations for Mirage Resorts from 1996 to 2000. Prior to that, she held various positions with the Las Vegas Chamber of Commerce between 1990 and 1996, including Director of Marketing, Vice President of Marketing and Senior Vice President of Government Affairs. Ms. Mathur is on the executive committees of Three Square, a not-for-profit organization, and NV Partnership for Inclusive Education.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the 2011 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this Item is incorporated by reference to the 2011 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this Item is incorporated by reference to the 2011 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference to the 2011 Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements, Financial Statement Schedules and Exhibits

All other schedules have been omitted because they are not required or are not applicable, or the required information is shown in the financial statements or notes thereto. Columns omitted from schedules have been omitted because the information is not applicable.

3. Exhibits:

Exhibits are listed in the Exhibit Index on pages 217 to 226.

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, NV Energy, Inc., Nevada Power Company and Sierra Pacific Power Company (both d/b/a NV Energy) have each duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized. The signatures for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

NV ENERGY, INC.
NEVADA POWER COMPANY d/b/a NV ENERGY
SIERRA PACIFIC POWER COMPANY d/b/a NV ENERGY

By /s/ MICHAEL W. YACKIRA

Michael W. Yackira
Director and
Chief Executive Officer (Principal Executive Officer)
February 24, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of NV Energy, Inc., Nevada Power Company and Sierra Pacific Power Company (both d/b/a NV Energy) and in the capacities indicated on the 24th day of February, 2011.

/s/ Dilek L. Samil Dilek L. Samil Chief Financial Officer (Principal Financial Officer)	/s/ E. Kevin Bethel E. Kevin Bethel Chief Accounting Officer (Principal Accounting Officer)
/s/ Joseph B. Anderson, Jr. Joseph B. Anderson, Jr. Director	/s/ Glenn C. Christenson Glenn C. Christenson Director
/s/ Susan F. Clark Susan F. Clark Director	/s/ Stephen E. Frank Stephen E. Frank Director
/s/ Brian J. Kennedy Brian J. Kennedy Director	/s/ Maureen T. Mullarkey Maureen T. Mullarkey Director
/s/ John F. O'Reilly John F. O'Reilly Director	/s/ Philip G. Satre Philip G. Satre Director and Chairman of the Board
/s/ Donald D. Snyder Donald D. Snyder Director	/s/ Michael W. Yackira Michael W. Yackira Director and Chief Executive Officer (Principal Executive Officer)

NV Energy, Inc.

Schedule II - Consolidated Valuation and Qualifying Accounts

For The Years Ended December 31, 2010, 2009 and 2008

(Dollars in Thousands)

	Provision for Uncollectible Accounts
Balance at January 1, 2008	$ 36,145
Provision charged to income	16,686
Amounts written off, less recoveries	(19,947)
Balance at December 31, 2008	$ 32,884
Balance at January 1, 2009	$ 32,884
Provision charged to income	21,839
Amounts written off, less recoveries	(22,382)
Balance at December 31, 2009	$ 32,341
Balance at January 1, 2010	$ 32,341
Provision charged to income	15,551
Amounts written off, less recoveries	(19,208)
Balance at December 31, 2010	$ 28,684

Nevada Power Company

Schedule II - Consolidated Valuation and Qualifying Accounts

For The Years Ended December 31, 2010, 2009 and 2008

(Dollars in Thousands)

	Provision for Uncollectible Accounts
Balance at January 1, 2008	$ 30,392
Provision charged to income	16,858
Amounts written off, less recoveries	(16,629)
Balance at December 31, 2008	$ 30,621
Balance at January 1, 2009	$ 30,621
Provision charged to income	17,519
Amounts written off, less recoveries	(18,765)
Balance at December 31, 2009	$ 29,375
Balance at January 1, 2010	$ 29,375
Provision charged to income	13,147
Amounts written off, less recoveries	(16,094)
Balance at December 31, 2010	$ 26,428

Sierra Pacific Power Company

Schedule II - Consolidated Valuation and Qualifying Accounts

For The Years Ended December 31, 2010, 2009 and 2008

(Dollars in Thousands)

	Provision for Uncollectible Accounts
Balance at January 1, 2008	$ 5,753
Provision charged to income	(173)
Amounts written off, less recoveries	(3,318)
Balance at December 31, 2008	$ 2,262
Balance at January 1, 2009	$ 2,262
Provision charged to income	4,321
Amounts written off, less recoveries	(3,617)
Balance at December 31, 2009	$ 2,966
Balance at January 1, 2010	$ 2,966
Provision charged to income	2,404
Amounts written off, less recoveries	(3,114)
Balance at December 31, 2010	$ 2,256

2010 FORM 10-K EXHIBIT INDEX

(a) Exhibits Index

Certain of the following exhibits with respect to NV Energy, Inc. and its subsidiaries, Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy, are filed herewith. Certain other of such exhibits have heretofore been filed with the SEC and are incorporated herein by reference.

(* filed herewith)

(3) NV Energy, Inc.

- Restated Articles of Incorporation of NV Energy, Inc. effective December 23, 2008, as amended (filed as Exhibit 3.1 to Form 10-Q for the quarter ended March 31, 2009).
- By-laws of NV Energy, Inc., as amended through February 4, 2011 (filed as Exhibit 3.1 to Form 8-K dated February 9, 2011).

Nevada Power Company

- Restated Articles of Incorporation of Nevada Power Company, dated July 28, 1999 (filed as Exhibit 3(B) to Form 10-K for year ended December 31, 1999).
- Amended and Restated By-Laws of Nevada Power Company dated July 28, 1999 (filed as Exhibit 3(C) to Form 10-K for year ended December 31, 1999).

Sierra Pacific Power Company

- Restated Articles of Incorporation of Sierra Pacific Power Company dated October 25, 2006 (filed as Exhibit 3.1 to Form 10-Q for the quarter ended September 30, 2006).
- By-laws of Sierra Pacific Power Company, as amended through November 13, 1996 (filed as Exhibit (3)(A) to Form 10-K for the year ended December 31, 1996).

(4) NV Energy, Inc.

- Indenture between NV Energy, Inc. (under its former name, Sierra Pacific Resources) and The Bank of New York, dated May 1, 2000, for the issuance of debt securities (filed as Exhibit 4.1 to Form 8-K dated May 22, 2000).
- Agreement of Resignation, Appointment and Acceptence dated November 6, 2009 by and among NV Energy, Inc., The Bank of New York Mellon and The Bank of New York Trust Company, N.A. (filed as Exhibit 4.1 to Form 10-K for the year ended December 31, 2009).
- Officers' Certificate dated August 12, 2005, establishing the terms of NV Energy, Inc.'s (under its former name, Sierra Pacific Resources) 6¾% Senior Notes due 2017 (filed as Exhibit 4.1 to Form 10-Q for the quarter ended September 30, 2005).
- Form of NV Energy, Inc.'s (under its former name, Sierra Pacific Resources) 6¾% Senior Notes due 2017 (filed as Exhibit 4.2 to Form 10-Q for the quarter ended September 30, 2005).

- Officers' Certificate establishing the terms of NV Energy's 6.25% Senior Notes due 2020 (filed as Exhibit 4.1 to Form 8-K dated November 19, 2010).
- Form of NV Energy's 6.25% Senior Notes due 2020 (filed as Exhibit A to Exhibit 4.1 to Form 8-K dated November 19, 2010).

Nevada Power Company

- General and Refunding Mortgage Indenture, dated May 1, 2001, between Nevada Power Company and The Bank of New York, as Trustee (filed as Exhibit 4.1(a) to Form 10-Q for the quarter ended June 30, 2001).
- Agreement of Resignation, Appointment and Acceptance dated November 6, 2009 by and among Nevada Power Company d/b/a NV Energy, The Bank of New York Mellon and The Bank of New York Trust Company, N.A. (filed as Exhibit 4.2 to Form 10-K for the year ended December 31, 2009).
- First Supplemental Indenture, dated as of May 1, 2001, establishing Nevada Power Company's 8.25% General and Refunding Mortgage Bonds, Series A, due June 1, 2011 (filed as Exhibit 4.1(b) to Form 10-Q for the quarter ended June 30, 2001).
- Officer's Certificate establishing the terms of Nevada Power Company's 8.25% General and Refunding Mortgage Bonds, Series A, due June 1, 2011 (filed as Exhibit 4.I(c) to Form 10-Q for the quarter ended June 30, 2001).
- Form of Nevada Power Company's 8.25% General and Refunding Mortgage Bonds, Series A, due June 1, 2011 (filed as Exhibit 4.1(d) to Form 10-Q for the quarter ended June 30, 2001).
- Officer's Certificate establishing the terms of Nevada Power Company's 6½% General and Refunding Mortgage Notes, Series I, due 2012 (filed as Exhibit 4.1 to Form 10-Q for quarter ended June 30, 2004).
- Form of Nevada Power Company's 6½% General and Refunding Mortgage Notes, Series I due 2012 (filed as Exhibit 4.2 to Form 10-Q for quarter ended June 30, 2004).
- Officer's Certificate establishing the terms of Nevada Power Company's 5⅞% General and Refunding Mortgage Notes, Series L, due 2015 (filed as Exhibit 4(A) to Form 10-K filed for year ended December 31, 2005).
- Form of Nevada Power Company's 5⅞% General and Refunding Mortgage Notes, Series L, due 2015 (filed as Exhibit 4(B) to Form 10-K filed for year ended December 31, 2005).
- Officer's Certificate establishing the terms of Nevada Power Company's 5.95% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Exhibit 4(A) to Form 10-K for the year ended December 31, 2005).
- Form of Nevada Power Company's 5.95% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Exhibit 4(B) to Form 10-K for the year ended December 31, 2005).
- Officer's Certificate establishing the terms of Nevada Power Company's 6.650% General and Refunding Mortgage Notes, Series N, due 2036 (filed as Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2006).

- Form of Nevada Power Company's 6.650% General and Refunding Mortgage Notes, Series N, due 2036 (filed as Appendix A to Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2006).
- Officer's Certificate establishing the terms of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series O, due 2018 (filed as Exhibit 4.7 to Form S-4 filed June 7, 2006).
- Form of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series O, due 2018 (filed as Appendix A to Exhibit 4.7 to Form S-4 filed June 7, 2006).
- Officer's Certificate establishing the terms of Nevada Power Company's 6.750% General and Refunding Mortgage Notes, Series R, due 2037 (filed as Exhibit 4.1 to Form 8-K dated June 27, 2007).
- Form of Nevada Power Company's 6.750% General and Refunding Mortgage Notes, Series R, due 2037 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated June 27, 2007).
- Officer's Certificate establishing the terms of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series S, due 2018 (filed as Exhibit 4.1 to Form 8-K dated July 28, 2008).
- Form of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series S, due 2018 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated July 28, 2008).
- Officer's Certificate establishing the terms of Nevada Power Company d/b/a NV Energy's 7.375% General and Refunding Mortgage Notes, Series U, due 2014 (filed as Exhibit 4.1 to Form 8-K dated January 8, 2009).
- Form of Nevada Power Company d/b/a NV Energy's 7.375% General and Refunding Mortgage Notes, Series U, due 2014 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated January 8, 2009).
- Officer's Certificate establishing the terms of Nevada Power Company d/b/a NV Energy's 7.125% General and Refunding Mortgage Notes, Series V, due 2019 (filed as Exhibit 4.1 to Form 8-K dated February 25, 2009).
- Form of Nevada Power Company d/b/a NV Energy's 7.125% General and Refunding Mortgage Notes, Series V, due 2019 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated February 25, 2009).
- Officers' Certificate establishing the terms of Nevada Power Company d/b/a NV Energy's 5.375% General and Refunding Mortgage Notes, Series X, due 2040 (filed as Exhibit 4.1 to Form 8-K dated September 10, 2010).
- Form of Nevada Power Company d/b/a NV Energy's 5.375% General and Refunding Mortgage Notes, Series X, due 2040 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated September 10, 2010).

Sierra Pacific Power Company

- General and Refunding Mortgage Indenture, dated as of May 1, 2001, between Sierra Pacific Power Company and The Bank of New York as Trustee (filed as Exhibit 4.2(a) to Form 10-Q for the quarter ended June 30, 2001).

- Second Supplemental Indenture, dated as of October 30, 2006, to subject additional properties of Sierra Pacific Power Company located in the State of California to the lien of the General and Refunding Mortgage Indenture and to correct defects in the original Indenture (filed as Exhibit 4(A) to Form 10-K for the year ended December 31, 2006).
- Agreement of Resignation, Appointment and Acceptence dated November 6, 2009 by and among Sierra Pacific Power Company d/b/a NV Energy, The Bank of New York Mellon and The Bank of New York Trust Company, N.A. (filed as Exhibit 4.3 to Form 10-K for the year ended December 31, 2009).
- Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Exhibit 4.4 to Form 10-Q for the quarter ended March 31, 2006).
- Form of First Supplemental Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Exhibit 4.2 to Form 8-K dated August 18, 2009).
- Form of Sierra Pacific Power Company's 6% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Appendix A to Exhibit 4.2 to Form 8-K dated August 18, 2009).
- Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6.750% General and Refunding Mortgage Notes, Series P, due 2037 (filed as Exhibit 4.2 to Form 8-K dated June 27, 2007).
- Form of Sierra Pacific Power Company's 6.750% General and Refunding Mortgage Notes, Series P, due 2037 (filed as Appendix A to Exhibit 4.2 to Form 8-K dated June 27, 2007).
- Officer's Certificate establishing the terms of Sierra Pacific Power Company's 5.45% General and Refunding Mortgage Notes, Series Q, due 2013 (filed as Exhibit 4.1 to Form 8-K dated August 28, 2008).
- Form of Sierra Pacific Power Company's 5.45% General and Refunding Mortgage Notes, Series Q, due 2013 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated August 28, 2008).

(10) NV Energy, Inc., Nevada Power Company and Sierra Pacific Power Company:

- Transmission Use and Capacity Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2010).

NV Energy, Inc.

- Written description of employment arrangement for Jeffrey L. Ceccarelli (filed as Exhibit 10(C) to Form 10-K for year ended December 31, 2007).
- Employment Letter dated May 9, 2007 for Michael W. Yackira (filed as Exhibit 10(D) to Form 10-K for year ended December 31, 2007).
- Paul J. Kaleta Employment Letter dated January 9, 2006 (filed as Exhibit 10(A) to Form 10-K for the year ended December 31, 2005).

- Roberto Denis Employment Letter dated July 11, 2003 (filed as Exhibit 10(B) to Form 10-K for the year ended December 31, 2003).
- NV Energy, Inc. (under its former name, Sierra Pacific Resources) Executive Change of Control Policy, effective January 1, 2008 (filed as Exhibit 10.1 to Form 10-K for the year ended December 31, 2008).
- NV Energy, Inc. (under its former name, Sierra Pacific Resources) Amended and Restated 2004 Executive Long-Term Incentive Plan (filed as Appendix A to 2008 Proxy Statement).
- NV Energy, Inc. (under its former name, Sierra Pacific Resources) 2003 Non-Employee Director Stock Plan, as amended (filed as Exhibit 99.2 to Form S-8 dated October 19, 2007).
- NV Energy, Inc. Amended and Restated Employee Stock Purchase Plan (filed as Exhibit 10.1 to Form 10-K for the year ended December 31, 2009).
- Separation Agreement dated February 17, 2010, between NV Energy, Inc. and William D. Rogers (filed as Exhibit 10.2 to Form 10-K for the year ended December 31, 2009).
- Assistance Agreement dated March 12, 2010 between the U.S. Department of Energy and NV Energy, Inc. (filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2010).
- Dilek L. Samil Employment Letter dated April 28, 2010 (filed as Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2010).
- Form of Performance Unit Agreement (filed as Exhibit 10.1 to Form 8-K dated February 9, 2011).
- Form of Performance Share Agreement (filed as Exhibit 10.2 to Form 8-K dated February 9, 2011).
- Form of Restricted Stock Unit Agreement (filed as Exhibit 10.3 to Form 8-K dated February 9, 2011).

Nevada Power Company

- Collective Bargaining Agreement dated as of February 1, 2008, effective through February 1, 2011, between Nevada Power Company and the International Brotherhood of Electrical Workers Local Union No. 396 (filed as Exhibit 10.2 to Form 10-K for the year ended December 31, 2008).
- Asset Purchase Agreement dated April 21, 2008, between Reliant Energy Wholesale Generation, LLC, Reliant Energy Asset Management, LLC and Nevada Power Company (filed as Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2008).
- Joint Tenant Contract, dated September 18, 2007, between Nevada Power Company as Tenant, and Beltway Business Park Warehouse No. 2, LLC as Owner, relating to Nevada Power Company's South Operations Center facility (filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2007).
- Lease, dated December 11, 2006, between Nevada Power Company as lessee and Beltway Business Park Warehouse No. 2, LLC as lessor, relating to Nevada Power Company's South Operations Center facility (filed as Exhibit 10(A) to Form 10-K for the year ended December 31, 2006).

- Financing Agreement between Clark County, Nevada and Nevada Power Company, dated August 1, 2006 (relating to Clark County, Nevada $39,500,000 Pollution Control Refund Revenue Bonds Series 2006) (filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2006).
- Financing Agreement between Coconino County, Arizona Pollution Control Corporation and Nevada Power Company, dated August 1, 2006 (relating to Coconino County, Arizona $13,000,000 Pollution Control Corporation Refunding Revenue Bonds Series 2006B) (filed as Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2006).
- Financing Agreement between Coconino County, Arizona Pollution Control Corporation and Nevada Power Company, dated August 1, 2006 (relating to Coconino County, Arizona $40,000,000 Pollution Control Corporation Refunding Revenue Bonds Series 2006A) (filed as Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2006).
- Financing Agreement No. 1 between Clark County, Nevada and Nevada Power Company, dated June 1, 2000 (Series 2000A) (filed as Exhibit 10(O) to Form 10-K for the year ended December 31, 2000).
- Financing Agreement between Clark County, Nevada and Nevada Power Company dated October 1, 1995 (relating to Clark County, Nevada $76,750,000 Industrial Development Revenue Bonds, Series 1995A) (filed as Exhibit 10.75 to Form 10-K, File No. 1-4698, for the year ended December 31, 1995).
- Financing Agreement between Clark County, Nevada and Nevada Power Company dated October 1, 1995 (relating to Clark County, Nevada $85,000,000 Industrial Development Refunding Revenue Bonds, Series 1995B) (filed as Exhibit 10.76 to Form 10-K, File No. 1-4698, for the year ended December 31, 1995).
- Financing Agreement between Clark County, Nevada and Nevada Power Company dated October 1, 1995 (relating to Clark County, Nevada $76,750,000 Industrial Development Revenue Bonds, Series 1995A and $44,000,000 Industrial Development Refunding Revenue Bonds, Series 1995C) (filed as Exhibit 10.77 to Form 10-K, File No. 1-1698, for the year ended December 31, 1995).
- Financing Agreement between Clark County, Nevada and Nevada Power Company dated October 1, 1995 (relating to Clark County, Nevada $20,300,000 Pollution Control Refunding Revenue Bonds, Series 1995D) (filed as Exhibit 10.78 to Form 10-K, File No. 1-4698, for the year ended December 31, 1995).
- Participation Agreement Reid Gardner Unit No. 4 dated July 11, 1979 between Nevada Power Company and California Department of Water Resources (filed as Exhibit 5.34 to Form S-7, File No. 2-65097).
- Amended Mohave Project Coal Slurry Pipeline Agreement dated May 26, 1976 between Peabody Coal Company and Black Mesa Pipeline, Inc. (Exhibit B to Exhibit 10.18) (filed as Exhibit 5.36 to Form S-7, File No. 2-56356).
- Navajo Project Co-Tenancy Agreement dated March 23, 1976 between Nevada Power Company, Arizona Public Service Company, Department of Water and Power of the City of Los Angeles, Salt

River Project Agricultural Improvement and Power District, Tucson Gas & Electric Company and the United States of America (filed as Exhibit 5.31 to Form 8-K, File No. 1-4696, April 1974).

- Mohave Operating Agreement dated July 6, 1970 between Nevada Power Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company and Department of Water and Power of the City of Los Angeles (filed as Exhibit 13.26F to Form S-1, File No. 2-38314).
- Eldorado System Conveyance and Co-Tenancy Agreement dated December 20, 1967 between Nevada Power Company and Salt River Project Agricultural Improvement and Power District and Southern California Edison Company (filed as Exhibit 13.30 to Form S-9, File No. 2-28348).
- Mohave Project Plant Site Conveyance and Co-Tenancy Agreement dated May 29, 1967 between Nevada Power Company and Salt River Project Agricultural Improvement and Power District and Southern California Edison Company (filed as Exhibit 13.27 to Form S-9, File No. 2-28348).
- Sublease Agreement between Powveg Leasing Corp., as Lessor and Nevada Power Company as lessee, dated January 1, 1984 for lease of administrative headquarters (the primary term of the sublease ends in 2014 and the lessee has the option to extend the term up to 25 additional years) (filed as Exhibit 10.31 to Form 10-K, File No. 1-4698, for the year ended December 31, 1983).
- Revolving Credit Facility dated April 28, 2010 between Nevada Power Company and Wells Fargo, N.A., as administrative agent for the lenders (filed as Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2010).

Sierra Pacific Power Company

- Financing Agreement dated April 1, 2007 between Washoe County and Sierra Pacific Power Company (relating to Washoe County, Nevada $40,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2007A) (filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2007).
- Financing Agreement dated April 1, 2007 between Washoe County and Sierra Pacific Power Company (relating to Washoe County, Nevada $40,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2007B) (filed as Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2007).
- Financing Agreement dated November 1, 2006 between Humboldt County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Humboldt County, Nevada $49,750,000 Pollution Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006) (filed as Exhibit 10(B) to Form 10-K for the year ended December 31, 2006).
- Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $58,750,000 Gas Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006A) (filed as Exhibit 10(C) to Form 10-K for the year ended December 31, 2006).
- Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $75,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company

Project) Series 2006B) (filed as Exhibit 10(D) to Form 10-K for the year ended December 31, 2006).

- Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $84,800,000 Gas and Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006C) (filed as Exhibit 10(E) to Form 10-K for the year ended December 31, 2006).
- Lease dated January 30, 1986 between Sierra Pacific Power Company and Silliman Associates Limited Partnership relating to the Company's corporate headquarters building (filed as Exhibit (10)(I) to Form 10-K for the year ended December 31, 1992).
- Letter of Amendment dated May 18, 1987 to Lease dated January 30, 1986 between Sierra Pacific Power Company and Silliman Associates Limited Partnership relating to the company's corporate headquarters building (filed as Exhibit (10)(K) to Form 10-K for the year ended December 31, 1993).
- Collective Bargaining Agreement dated as of August 16, 2010, effective through August 15, 2013, between Sierra Pacific Power Company and the International Brotherhood of Electrical Workers Local Union No. 1245 (filed as Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2010).
- Revolving Credit Facility dated April 28, 2010 between Sierra Pacific Power Company and Bank of America, N.A., as administrative agent for the lenders (filed as Exhibit 10.4 to Form 10-Q for the quarter ended September 30, 2010).

(11) Nevada Power Company and Sierra Pacific Power Company

- Nevada Power Company and Sierra Pacific Power Company are wholly owned subsidiaries and, in accordance with the accounting guidance for earnings per share as reflected in the Earnings Per Share Topic of the FASC, earnings per share data have been omitted.

(12) NV Energy, Inc.

- *(12.1) Statement regarding computation of Ratios of Earnings to Fixed Charges.

Nevada Power Company

- *(12.2) Statement regarding computation of Ratios of Earnings to Fixed Charges.

Sierra Pacific Power Company

- *(12.3) Statement regarding computation of Ratios of Earnings to Fixed Charges.

(21) NV Energy, Inc.

- Nevada Power Company d/b/a NV Energy, a Nevada Corporation.
  Sierra Pacific Power Company d/b/a NV Energy, a Nevada Corporation.
  Lands of Sierra Inc., a Nevada Corporation.
  Sierra Energy Company dba e-three, a Nevada Corporation.

Sierra Gas Holdings Company, a Nevada Corporation.
Sierra Pacific Energy Company, a Nevada Corporation.
Sierra Water Development Company, a Nevada Corporation.
Sierra Pacific Communications, a Nevada Corporation.
NVE Insurance Company, Inc., a Nevada Corporation.

Nevada Power Company

- Nevada Electric Investment Company, a Nevada Corporation.
  Commonsite, Inc., a Nevada Corporation.

Sierra Pacific Power Company

- Piñon Pine Company, a Nevada Corporation.
  Piñon Pine Investment Company, a Nevada Corporation.
  Piñon Pine Investment Co. LLC, a Nevada Limited Liability Company.
  GPSF-B, a Delaware Corporation.
  SPPC Funding LLC, a Delaware Limited Liability Company.

(23) NV Energy, Inc., Nevada Power Company and Sierra Pacific Power Company

- *(23.1) Consent of Independent Registered Public Accounting Firm in connection with NV Energy, Inc.'s Registration Statement Nos. 333-168978 and No. 333-168984 on Form S-3/ASR and Registration Statement Nos. 333-92651 and No. 333-146822 on Form S-8.
- *(23.2) Consent of Independent Registered Public Accounting Firm in connection with Nevada Power Company's Registration Statement No. 333-168984-02 on Form S-3ASR.
- *(23.3) Consent of Independent Registered Public Accounting Firm in connection with Sierra Pacific Power Company's Registration Statement No. 168984-01 on Form S-3ASR.

(31) NV Energy, Inc., Nevada Power Company and Sierra Pacific Power Company

- *(31.1) Annual Certification of Chief Executive Officer of NV Energy, Inc. Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- *(31.2) Annual Certification of Chief Executive Officer of Nevada Power Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- *(31.3) Annual Certification of Chief Executive Officer of Sierra Pacific Power Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- *(31.4) Annual Certification of Chief Financial Officer of NV Energy, Inc. Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- *(31.5) Annual Certification of Chief Financial Officer of Nevada Power Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- *(31.6) Annual Certification of Chief Financial Officer of Sierra Pacific Power Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(32) NV Energy, Inc., Nevada Power Company and Sierra Pacific Power Company

- *(32.1) Certification of Chief Executive Officer of NV Energy, Inc. Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- *(32.2) Certification of Chief Executive Officer of Nevada Power Company Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- *(32.3) Certification of Chief Executive Officer of Sierra Pacific Power Company Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- *(32.4) Certification of Chief Financial Officer of NV Energy, Inc. Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- *(32.5) Certification of Chief Financial Officer of Nevada Power Company Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- *(32.6) Certification of Chief Financial Officer of Sierra Pacific Power Company Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(99) Sierra Pacific Power Company

- Asset Purchase Agreement between Sierra Pacific Power Company d/b/a NV Energy and California Pacific Electric Company, LLC dated April 22, 2009 (filed as Exhibit 99.2 to Form 8-K dated January 5, 2011).

EXHIBIT 12.1

NV ENERGY, INC.
RATIOS OF EARNINGS TO FIXED CHARGES
(Dollars in Thousands)

	Year Ended December 31,				
	2010	2009	2008	2007	2006
EARNINGS AS DEFINED:					
Net Income	$226,984	$182,936	$208,887	$197,295	$279,792
Income Taxes	113,764	75,451	95,354	87,555	145,605
Fixed Charges	363,773	360,896	335,868	310,876	336,024
Capitalized Interest (allowance for borrowed funds used during construction)	(23,355)	(20,229)	(29,527)	(25,967)	(17,119)
Preferred Stock Dividend Requirement	-	-	-	-	(3,602)
Total	$681,166	$599,054	$610,582	$569,759	$740,700
FIXED CHARGES AS DEFINED:					
Interest Expensed and Capitalized[(1)]	$363,773	$360,896	$335,868	$310,876	$332,422
Preferred Stock Dividend Requirement	-	-	-	-	3,602
Total	$363,773	$360,896	$335,868	$310,876	$336,024
RATIO OF EARNINGS TO FIXED CHARGES	1.87	1.66	1.82	1.83	2.20

(1) Includes amortization of premiums, discounts, and capitalized debt expense and interest component of rent expense.

For the purpose of calculating the ratios of earnings to fixed charges, ''Earnings'' represents net income adjusted for income taxes and fixed charges excluding capitalized interest. For the year ended December 31, 2006, ''Earnings'' represents net income adjusted for pre-tax preferred stock dividend requirement of SPPC, income taxes and fixed charges excluding capitalized interest. ''Fixed charges'' represent the aggregate of interest charges on long-term debt (whether expensed or capitalized), the portion of rental expense deemed to be attributable to interest, and the pre-tax preferred stock dividend requirement of SPPC.

EXHIBIT 12.2

NEVADA POWER COMPANY
RATIOS OF EARNINGS TO FIXED CHARGES
(Dollars in Thousands)

	Year Ended December 31,				
	2010	2009	2008	2007	2006
EARNINGS AS DEFINED:					
Net Income	$185,943	$134,284	$151,431	$165,694	$224,540
Income Taxes	91,757	61,652	71,382	78,352	117,510
Fixed Charges	240,830	247,290	210,067	190,836	190,333
Capitalized Interest (allowance for borrowed funds used during construction)	(21,443)	(17,184)	(20,063)	(13,196)	(11,614)
Total	$497,087	$426,042	$412,817	$421,686	$520,769
FIXED CHARGES AS DEFINED:					
Interest Expensed and Capitalized (1)	$240,830	$247,290	$210,067	$190,836	$190,333
Total	$240,830	$247,290	$210,067	$190,836	$190,333
RATIO OF EARNINGS TO FIXED CHARGES	2.06	1.72	1.97	2.21	2.74

(1) Includes amortization of premiums, discounts, and capitalized debt expense and interest component of rent expense

For the purpose of calculating the ratios of earnings to fixed charges, ''Earnings'' represents net income adjusted for income taxes and fixed charges excluding capitalized interest. ''Fixed charges'' represent the aggregate of interest charges on long-term debt (whether expensed or capitalized) and the portion of rental expense deemed attributable to interest.

EXHIBIT 12.3

SIERRA PACIFIC POWER COMPANY
RATIOS OF EARNINGS TO FIXED CHARGES
(Dollars in Thousands)

	Year ended December 31,				
	2010	2009	2008	2007	2006
EARNINGS AS DEFINED:					
Net Income	$ 72,375	$ 73,085	$ 90,582	$ 65,667	$ 57,709
Income Taxes	40,404	31,225	37,603	26,009	27,829
Fixed Charges	72,815	74,955	84,478	75,655	79,093
Capitalized Interest (allowance for borrowed funds used during construction)	(1,912)	(3,044)	(9,464)	(12,771)	(5,505)
Total	$183,682	$176,221	$203,199	$154,560	$159,126
FIXED CHARGES AS DEFINED:					
Interest Expensed and Capitalized (1)	$ 72,815	$ 74,955	$ 84,478	$ 75,655	$ 79,093
Total	$ 72,815	$ 74,955	$ 84,478	$ 75,655	$ 79,093
RATIO OF EARNINGS TO FIXED CHARGES	2.52	2.35	2.41	2.04	2.01

(1) Includes amortization of premiums, discounts, and capitalized debt expense and interest component of rent expense

For the purpose of calculating the ratios of earnings to fixed charges, ‘‘Earnings’’ represent net income before, solely with respect to the year ended December 31, 2006, pre-tax preferred stock dividend requirement adjusted for income taxes and fixed charges excluding capitalized interest. ‘‘Fixed charges’’ represent the aggregate of interest charges on long-term debt (whether expensed or capitalized) and the portion of rental expense deemed attributable to interest.

EXHIBIT 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER REQUIRED BY SECTION 302(A) OF THE SARBANES-OXLEY ACT OF 2002

NV ENERGY, INC.
(“Registrant”)

I, Michael W. Yackira, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2010 of NV Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit

committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 25, 2011

/s/ Michael W. Yackira

Michael W. Yackira
President and Chief Executive Officer
NV Energy, Inc.
(Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER REQUIRED BY SECTION 302(A) OF THE SARBANES-OXLEY ACT OF 2002

NEVADA POWER COMPANY (dba NV ENERGY) (“Registrant”)

I, Michael W. Yackira, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2010 of Nevada Power Company (dba NV Energy);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit

committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 25, 2011

/s/ Michael W. Yackira

Michael W. Yackira
President and Chief Executive Officer
Nevada Power Company (dba NV Energy)
(Principal Executive Officer)

EXHIBIT 31.3

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER REQUIRED BY SECTION 302(A) OF THE SARBANES-OXLEY ACT OF 2002

SIERRA PACIFIC POWER COMPANY (dba NV ENERGY) ("Registrant")

I, Michael W. Yackira, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2010 of Sierra Pacific Power Company (dba NV Energy);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit

committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 25, 2011

/s/ Michael W. Yackira

Michael W. Yackira
Chief Executive Officer
Sierra Pacific Power Company (dba NV Energy)
(Principal Executive Officer)

EXHIBIT 31.4

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER REQUIRED BY SECTION 302(A) OF THE SARBANES-OXLEY ACT OF 2002

NV ENERGY, INC.
("Registrant")

I, Dilek L. Samil, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2010 of NV Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit

committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 25, 2011

/s/ Dilek L. Samil

Dilek L. Samil
Chief Financial Officer
NV Energy, Inc.
(Principal Financial Officer)

EXHIBIT 31.5

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER REQUIRED BY SECTION 302(A) OF THE SARBANES-OXLEY ACT OF 2002

NEVADA POWER COMPANY (dba NV ENERGY)
("Registrant")

I, Dilek L. Samil, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2010 of Nevada Power Company (dba NV Energy);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit

committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 25, 2011

/s/ Dilek L. Samil

Dilek L. Samil
Chief Financial Officer
Nevada Power Company (dba NV Energy)
(Principal Financial Officer)

EXHIBIT 31.6

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER REQUIRED BY SECTION 302(A) OF THE SARBANES-OXLEY ACT OF 2002

SIERRA PACIFIC POWER COMPANY (dba NV ENERGY) (“Registrant”)

I, Dilek L. Samil, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2010 of Sierra Pacific Power Company (dba NV Energy);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit

committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 25, 2011

/s/ Dilek L. Samil

Dilek L. Samil
Chief Financial Officer
Sierra Pacific Power Company (dba NV Energy)
(Principal Financial Officer)

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

**NV ENERGY, INC.
("Registrant")**

In connection with this report of NV Energy, Inc. on Form 10-K for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof, I, Michael W. Yackira, President and Chief Executive Officer of registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. This report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in this report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

/s/ Michael W. Yackira

Michael W. Yackira
President and Chief Executive Officer
NV Energy, Inc.
(Principal Executive Officer)
February 25, 2011

This Certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent the registrant specifically incorporates it by reference.

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

NEVADA POWER COMPANY (dba NV ENERGY)
(“Registrant”)

In connection with this report of Nevada Power Company (dba NV Energy) on Form 10-K for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof, I, Michael W. Yackira, President and Chief Executive Officer of registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. This report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in this report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

/s/ Michael W. Yackira

Michael W. Yackira
President and Chief Executive Officer
Nevada Power Company (dba NV Energy)
(Principal Executive Officer)
February 25, 2011

This Certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent the registrant specifically incorporates it by reference.

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.3

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

SIERRA PACIFIC POWER COMPANY (dba NV ENERGY)
(“Registrant”)

In connection with this report of Sierra Pacific Power Company (dba NV Energy) on Form 10-K for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof, I, Michael W. Yackira, Chief Executive Officer of registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. This report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in this report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

/s/ Michael W. Yackira

Michael W. Yackira
Chief Executive Officer
Sierra Pacific Power Company (dba NV Energy)
(Principal Executive Officer)
February 25, 2011

This Certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent the registrant specifically incorporates it by reference.

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.4

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

NV ENERGY, INC.
(''Registrant'')

In connection with this report of NV Energy, Inc. on Form 10-K for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof, I, Dilek L. Samil, Chief Financial Officer of registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. This report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in this report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

/s/ Dilek L. Samil

Dilek L. Samil Chief Financial Officer
NV Energy, Inc.
(Principal Financial Officer)
February 25, 2011

This Certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent the registrant specifically incorporates it by reference.

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.5

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

NEVADA POWER COMPANY (dba NV ENERGY)
(“Registrant”)

In connection with this report of Nevada Power Company (dba NV Energy) on Form 10-K for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof, I, Dilek L. Samil, Chief Financial Officer of registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. This report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in this report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

/s/ Dilek L. Samil

Dilek L. Samil
Chief Financial Officer
Nevada Power Company (dba NV Energy)
(Principal Financial Officer)
February 25, 2011

This Certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent the registrant specifically incorporates it by reference.

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.6

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

SIERRA PACIFIC POWER COMPANY (dba NV ENERGY)
("Registrant")

In connection with this report of Sierra Pacific Power Company (dba NV Energy) on Form 10-K for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof, I, Dilek L. Samil, Chief Financial Officer of registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. This report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in this report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

/s/ Dilek L. Samil

Dilek L. Samil
Chief Financial Officer
Sierra Pacific Power Company (dba NV Energy)
(Principal Financial Officer)
February 25, 2011

This Certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent the registrant specifically incorporates it by reference.

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.