2001 ANNUAL REPORT

CALPINE

CALPINE

50 WEST SAN FERNANDO STREET
SAN JOSE, CALIFORNIA 95113
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April 12, 2002

Dear Fellow Calpine Shareholders,

2001 was the most tumultuous year the power industry has ever faced. In spite of this, it was a great year for Calpine, and helped prepare our company for the even greater challenges of 2002 and the tremendous opportunities in the years ahead. Most important, Calpine's business model has been validated and our long-range vision reinforced.

Calpine – 2001

Year of Dramatic Growth

Capacity (at 12/31/01)	11,100 mw	up 90%
Energy Generated	45 million mwh	up 75%
Revenue	$7.6 billion	up 198%
Earnings	$641.1 million	up 71%
EBITDA, as adjusted	$1.6 billion	up 57%
Employees (at 12/31/01)	3,719	up 75%

Let's look back at last year. It started with the California energy crisis. Electricity prices were driven through the roof by increased demand, supply shortages, high gas prices and a deeply flawed deregulation program. Calpine's view has always been that deregulation must lead to lower prices, more reliable service and more environmentally friendly power generation.

We stepped back from the California spot market when power prices began their wild ride and opted instead for bilateral contracts with load-serving entities — municipal and investor-owned utilities. We responded to Governor Davis' request for long-term contracts and entered into base load and peaking contracts at prices lower than our competitors. We could do this because we have the most efficient power plants in the state and were able to lock in gas costs through our Calpine Natural Gas Company (CNG) and through hedges negotiated by Calpine Energy Services. We've cooperated with the state to renegotiate these contracts in a way that benefits both parties.

Throughout the crisis, Calpine was seen by state authorities as part — and a big part — of the solution. We were never accused of "gouging" and no lawsuits were filed against us. Blackouts were averted last summer in large measure because Calpine brought on line three new power plants — Sutter, Los Medanos and South Point — with 1,657 megawatts in time for the summer peak demand. These were the only large, new plants to come on line in the state last summer.

Other challenges the industry faced in 2001 made headline news for months: Pacific Gas and Electric's bankruptcy, September 11, Enron's bankruptcy, recession and mild weather across the nation. The impacts on Calpine were lower electricity prices, liquidity and earnings challenges, lower credit ratings, uncertainty on credit rating criteria and significantly tighter capital markets. We're overcoming these obstacles in 2002 and will come through the challenging times a stronger, more focused company:

- We're continuing our construction program in 2002, but have slowed down the development of new projects until future energy prices are more certain and we have construction funding available at attractive rates.
- We've reduced overhead and cut all discretionary spending.
- We're overkilling the liquidity concerns by lowering our costs and raising additional capital.

Here are some highlights of Calpine's activities in 2001 and our plans for 2002:

Financing

Since September 11, Calpine has raised $5.4 billion in a number of capital transactions, demonstrating that even in the most difficult financial markets the company has the unequalled ability to raise large amounts of capital. Altogether, Calpine has raised $26.5 billion since our first debt offering in 1994.

Credit Rating

Calpine's credit rating was increased by two of the three rating agencies to investment-grade just before the Enron bankruptcy. It has since been lowered as the agencies apply more conservative standards across the power industry. We remain committed to strengthening our balance sheet and achieving an investment-grade credit rating from all rating agencies.

Financial Reporting

We've always adhered strictly to Generally Accepted Accounting Principles (GAAP) in our financial reporting. Nonetheless, the accounting rules under which we must operate are complex. In an effort to explain our reports so that they can be readily understood and are completely transparent, we have expanded our 10-K report (included with this Annual Report) and included explanations and examples when appropriate. We would appreciate your feedback. Let us know how well we've succeeded in making this complex accounting report more understandable.

Power Portfolio

Our portfolio of power plants grew in 2001 to 11,100 mw as we brought nearly 4,000 mw of new plants on line, and purchased power plants with a capacity of 1,475 mw. This is the largest fleet of modern power generating facilities in North America and a highly efficient plant in the United Kingdom. At year-end 2001, 27 Calpine plants totaling 15,200 mw were under construction. These units will go on line this year and next.

Calpine – International

In 2001, we made our first investment outside North America. We have identified Europe as a market where Calpine can apply the skillset we've developed in the United States. Europe is a large, industrialized economy; deregulation is proceeding under the European Union, and gas is becoming the fuel of choice across the continent. We acquired a new, highly efficient 1,200-mw project — a cogenerator at a large chemical complex — in the United Kingdom. We plan to expand from this foothold in the years ahead.

Natural Gas

With the acquisition of Encal Energy Ltd., an outstanding Calgary-based gas company, CNG expanded to become a major gas producer in Canada and the United States. CNG's total proven reserves at year-end 2001 were 1.3 trillion cubic feet equivalent. By owning gas reserves and operating gas fields, Calpine is able to hedge future gas costs against fixed power prices and gain invaluable marketing intelligence, enabling the company to assure gas supply to its power plants at below-market prices. Our goal is to produce, from Calpine-owned gas fields, at least 25% of the gas we consume.

Geothermal

Calpine continues to operate as the world's largest geothermal company. The integration of 19 power plants and the related steam fields at The Geysers, north of San Francisco, has been a resounding success. A second pipeline is being built that will allow us to inject additional treated wastewater into The Geysers' steam fields in order to expand and extend this resource.

In June 2001, we opened a visitors' center in Middletown, California, which includes displays describing geothermal power, a history of The Geysers, and many other exhibits. Power plant and steam field tours are conducted from here daily. So far, more than 12,000 guests have visited the center.

Calpine is proceeding through a long, arduous process to permit a new 50-mw geothermal power plant at Glass Mountain, California, 30 miles south of the Oregon border — the largest undeveloped geothermal field in North America.

Calpine People

Challenging times require excellent people, and I'm proud to say that Calpine is rich in that respect, with the finest, most talented employees in the industry. Our staff has grown to over 3,700 people — the real strength of our company. With their continued focus and support, I'm confident our company will emerge even stronger and better positioned than before.

Looking Ahead

The demand for electric power is continuing to grow in America even as the older, inefficient and highly polluting power plants that make up the bulk of this country's power generation face increasing economic and environmental challenges.

A healthy, growing America will need power and Calpine will be there to provide it. Our goal remains to become the largest and most profitable power company in North America. We're well on our way to making this happen.

PETE CARTWRIGHT
Chairman, Chief Executive Officer and President

FINANCIAL HIGHLIGHTS

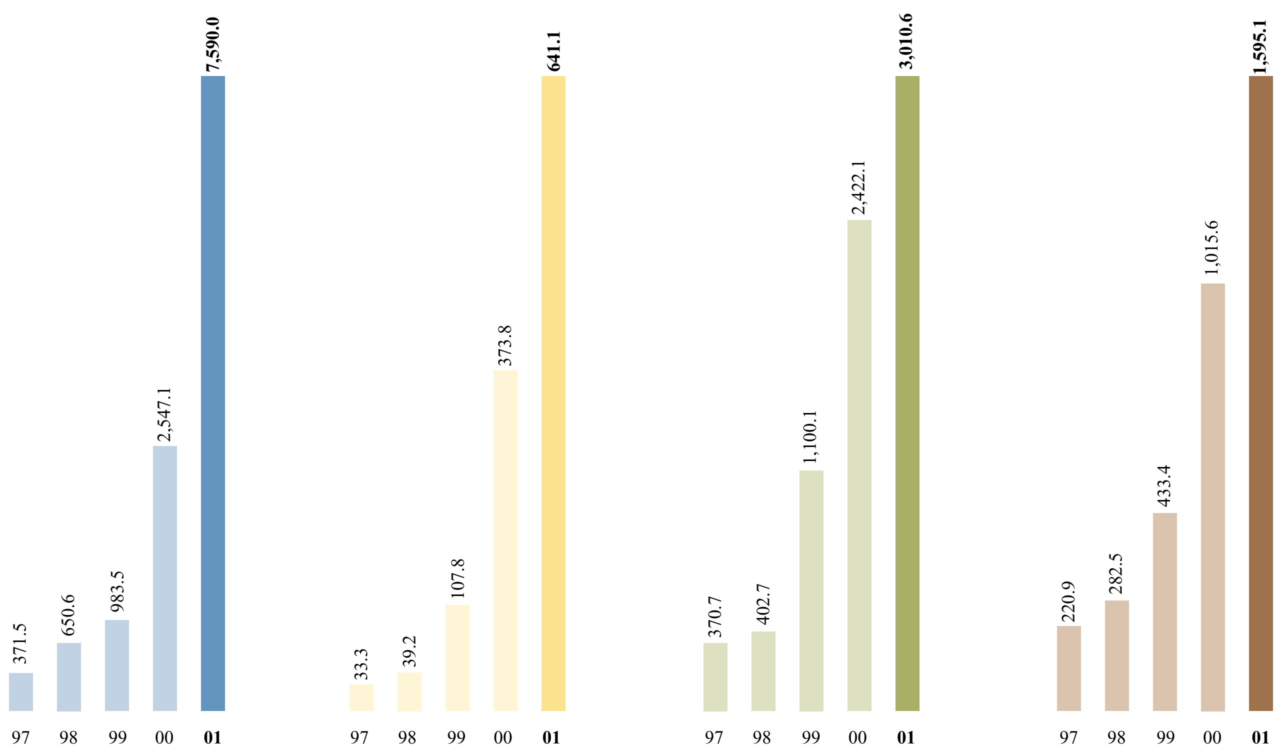
For the years ended December 31 (in millions, except per share amounts)	1997	1998	1999	2000	2001
Revenue	$ 371.5	$ 650.6	$ 983.5	$ 2,547.1	**$ 7,590.0**
Gross Profit	134.5	184.6	318.8	847.0	**1,331.5**
Net Income[1]	33.3	39.2	107.8	373.8	**641.1**
Diluted EPS[2]	0.18	0.21	0.45	1.20	**1.85**
Diluted EPS From Recurring Operations[3]	0.18	0.21	0.45	1.20	**1.92**
Weighted Shares Outstanding[4]	184.6	185.1	238.7	297.5	**317.9**

(1) Net Income before extraordinary items and cumulative effect of a change in accounting principle.

(2) Earnings per share before extraordinary items and cumulative effect of a change in accounting principle.

(3) Earnings per share, before deduction of merger expense in connection with the Encal Energy Ltd. pooling-of-interests transaction, and before extraordinary items and cumulative effect of a change in accounting principle.

(4) Before dilutive effect of certain convertible securities.



REVENUE
($ in millions)

NET INCOME[1]
($ in millions)

STOCKHOLDERS' EQUITY
($ in millions)

EBITDA, as adjusted[5]
($ in millions)

(5) This non-GAAP measure is defined as net income less income from unconsolidated investments, plus cash received from unconsolidated investments, plus provision for tax, plus interest expense, plus one-third of operating lease expense, plus depreciation and amortization, plus distributions on our company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts ("HIGH TIDES"). EBITDA, as adjusted, is presented not as a measure of operating results, but rather as a measure of our ability to service debt. EBITDA, as adjusted, should not be construed as an alternative to either (i) income from operations (determined in accordance with generally accepted accounting principles) or (ii) cash flows from operating activities (determined in accordance with generally accepted accounting principles).

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2001

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-12079

Calpine Corporation

(A Delaware Corporation)

I.R.S. Employer Identification No. 77-0212977

50 West San Fernando Street
San Jose, California 95113
Telephone: (408) 995-5115

Securities registered pursuant to Section 12(b) of the Act:
Calpine Corporation Common Stock, $.001 Par Value Registered on the New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (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 registrant's 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. ☐

Aggregate market value of the voting stock held by non-affiliates of the registrant as of March 26, 2002: $3.7 billion. Common stock outstanding as of March 26, 2002: 307,602,191 shares.

DOCUMENTS INCORPORATED BY REFERENCE.

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved.

(1) Designated portions of the Proxy Statement relating to the 2002 Annual Meeting of Shareholders . . . . Part III (Items 10, 11, 12 and 13)

FORM 10-K
ANNUAL REPORT
For the Year Ended December 31, 2001

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PART I

Item 1. *Business*

In addition to historical information, this report contains forward-looking statements. Such statements include those concerning Calpine Corporation's ("the Company's") expected financial performance and its strategic and operational plans, as well as all assumptions, expectations, predictions, intentions or beliefs about future events. You are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties that could cause actual results to differ materially from the forward-looking statements such as, but not limited to, (i) unseasonable weather patterns that reduce demand for power and natural gas, (ii) systemic economic slowdowns, which can adversely affect consumption of power by businesses and consumers, (iii) the timing and extent of deregulation of energy markets and the rules and regulations adopted on a transitional basis with respect thereto, (iv) the timing and extent of changes in commodity prices for energy, particularly natural gas and electricity, (v) commercial operations of new plants that may be delayed or prevented because of various development and construction risks, such as a failure to obtain financing and the necessary permits to operate or the failure of third-party contractors to perform their contractual obligations, (vi) cost estimates are preliminary and actual costs may be higher than estimated, (vii) a competitor's development of a lower-cost gas-fired power plant, (viii) risks associated with marketing and selling power from power plants in the newly-competitive energy market, or (ix) the successful exploitation of an oil or gas resource that ultimately depends upon the geology of the resource, the total amount and cost to develop recoverable reserves, and operational factors relating to the extraction of natural gas. All information set forth in this filing is as of March 29, 2002, and Calpine undertakes no duty to update this information. Readers should carefully review the "Risk Factors" section of this document as well as in other documents filed with the Securities and Exchange Commission, including, but not limited to, the Quarterly Reports on Form 10-Q to be filed by the Company in fiscal year 2002.

OVERVIEW

Calpine is a leading independent power company engaged in the development, acquisition, ownership and operation of power generation facilities and the sale of electricity predominantly in the United States, but also in Canada and the United Kingdom. Calpine also is the world's largest producer of renewable geothermal energy, and we own 1.3 trillion cubic feet equivalent of proved natural gas reserves in Canada and the United States. We have experienced significant growth in all aspects of our business over the last five years. Currently, we own interests in 64 power plants having a net capacity of 12,090 megawatts. We also have 24 gas-fired projects under construction having a net capacity of 14,142 megawatts and have 34 projects in advanced development with a net capacity of 15,100 megawatts. Construction of these advanced development projects will proceed if and when market fundamentals are sound, our return on investment criteria are expected to be met, and financing is available on attractive terms. The completion of the projects currently under construction would give us interests in 86 power plants located in 21 states, 3 Canadian provinces and the United Kingdom, having a net capacity of 26,232 megawatts. Of this total generating capacity, 97% will be attributable to gas-fired facilities and 3% will be attributable to geothermal facilities. As a result of our expansion program, our net income, fully diluted earnings per share and assets have grown significantly from 1997 to 2001, as shown in the table below, although we do not anticipate our growth to continue at these rates in view of our revised construction and advanced development activities described within this document.

	1997	2001	Compound Annual Growth Rate
	(Dollars in millions, except per share amounts)		
Net income	$ 33.3	$ 648.1	110%
Fully diluted earnings per share(1)	0.18	1.85	79%
Fully diluted earnings per share from recurring operations(2)	0.18	1.92	81%
Total assets	1,643.2	21,309.3	90%

(1) before extraordinary items

(2) before deduction of merger expense in connection with the Encal Energy Ltd. pooling-of-interests transaction, and before extraordinary items and cumulative effect of a change in accounting principle.

In the last few years we have built our wholly owned subsidiary Calpine Energy Services ("CES") into an effective power and gas marketing, risk management and asset optimization organization. We continue to exploit our world class development capabilities as we add power facilities in most of the major markets where natural gas is the fuel "on the margin", meaning that incremental demand is generally met by gas-fired plants. We are also developing the system operations management teams and information technology capabilities to enhance the economic performance of our systems of assets in our major markets and to provide load-following and other ancillary services to our customers. These operational optimization systems, combined with the marketing and risk management capabilities of CES, enable us to add value to traditional commodity products in a way that not all competitors can match.

We have acquired gas reserves (1.3 trillion cubic feet equivalent of proved reserves on hand at December 31, 2001) and a seasoned oil and gas production and management team to give us a broader range of fuel sourcing options. Our construction organization has assembled what we believe to be the best-in-industry team of construction management professionals to ensure that our projects are built using our standard Calpine design specifications at the lowest feasible cost consistent with our exacting operational standards. We have established strategic alliances with the best equipment manufacturers in the world for gas turbine generators, steam turbine generators and heat recovery steam generators.

With a vision of enhancing the performance of our modern portfolio of gas-fired power plants and lowering our maintenance costs, we have readied our wholly owned subsidiary Power Systems Manufacturing to design and manufacture certain combustion system and turbine blade parts.

As we build the nation's most modern and efficient portfolio of gas-fired generation assets and establish the low-cost position, we believe Calpine has uniquely positioned itself to compete in the deregulated marketplace of the future. The ultimate goal and sustaining principle of deregulation is to lower the price of power to consumers while not sacrificing reliability. While we expect power prices to rise and fall over time as a function of economic activity, weather patterns and supply and demand relationships, we take a long-term view of the market and have the discipline to stay the course and realize the benefits of our investments. We believe that our vertically integrated low-cost approach to power generation gives us a competitive advantage within our industry.

THE MARKET

The electric power industry represents one of the largest industries in the United States and impacts nearly every aspect of our economy, with an estimated end-user market of over $240 billion of electricity sales in 2001. The power generation industry historically has been largely characterized by electric utility monopolies producing electricity from old, inefficient, high-cost generating facilities selling to a captive customer base. Industry trends and regulatory initiatives have transformed the existing market into a more competitive market where end-users in certain power markets may purchase electricity from a variety of suppliers, including independent power producers, power marketers, regulated public utilities and others.

The North American Electric Reliability Council ("NERC") estimates that in the United States, peak summer electric demand in 2001 totaled approximately 709,000 megawatts ("MW"), while summer generating capacity in 2001 totaled approximately 793,000 MW, creating a reserve margin of 84,000 MW, or 11.8% of peak summer demand. Reserve margins are generally targeted to be 15-20% to provide for load forecasting errors, scheduled and unscheduled plant outages and local area grid protection. NERC forecasts average annual growth of 1.95% from 2001 to 2010 in the United States in peak summer demand. We believe this growth rate to be conservative and that a 2.5% annual growth rate is more realistic based on actual compounded annual growth rates reported by NERC and based on other analysts. Summer generating capacity fuel sources in the United States are estimated to be comprised of coal (38.0%); nuclear (12.3%);

hydro (9.7%); gas (17.2%); oil (5.5%); dual fuel (12.4%); and other (4.9%). At the end of 2001, Calpine's 9,860 MW of net operating generating capacity in the United States consisted of 9,010 MW gas-fired and 850 MW geothermal and represented approximately 1.2% of total estimated summer generating capacity in the United States, 6.6% of the 136,000 MW estimated total gas-fired summer generating capacity and 47.2% of the 1,800 MW estimated total geothermal summer generating capacity in the United States.

NERC similarly estimates that in Canada, peak winter electric demand in 2001 totaled approximately 87,000 MW, while winter generating capacity in 2001 totaled approximately 100,000 MW, creating a reserve margin of 13,000 MW, or 14.9% of peak winter demand. NERC forecasts average annual growth of 1.39% in Canada from 2001 to 2010 in peak winter demand. Winter generating capacity fuel sources in Canada are estimated to be comprised of coal (19.0%); nuclear (15.0%); hydro (53.1%); gas (5.7%); oil (5.4%); and other (1.8%).

There is a significant need for additional power generating capacity throughout the United States, both to satisfy increasing demand, as well as to replace old and inefficient generating facilities. We estimate that as much as 20%, or approximately 160,000 MW, of U.S. summer generating capacity is vulnerable to environmental or economic replacement by new state-of-the-art facilities. Due to environmental and economic considerations, we believe this new capacity will be provided predominantly by gas-fired facilities. We believe that these market trends will create substantial opportunities for efficient, low-cost power producers that can produce and sell energy to customers at competitive rates.

Our business model assumes that between 2002 and 2006 approximately 155,000 MW of new generating capacity additions will need to occur in the United States based on a 2.5% annual growth rate in peak summer demand, 20,000 MW of retirements due to environmental and economic obsolescence, and a 15.5% reserve margin at the end of 2006. We expect to provide a significant portion of the new generating capacity subject to the availability of capital on attractive terms. In the near-term we believe commodity prices will be low, but our long-term view remains optimistic.

STRATEGY

Our corporate vision is to repower America and, in so doing, to become the nation's largest and most profitable power producer. We will concentrate on markets in North America, primarily in the United States, and, to a lesser extent, on select Western European markets.

Our timeline to achieve this position and our other strategic objectives is flexible. Construction of our advanced development projects will proceed if and when market fundamentals are sound, our return on investment criteria are expected to be met, and financing is available on attractive terms. Our plans to grow our asset base rely primarily on our internal development and construction program and to a lesser extent on attractive acquisitions. The key elements of our growth plan are as follows:

- *Development of new and expansion of existing power plants.* We are actively pursuing the development of new and expansion of both baseload and peaking capacity at our existing highly efficient, low-cost, gas-fired power plants that replace old and inefficient generating facilities and meet the demand for new generation. Our strategy is to develop power plants in strategic geographic locations that enable us to leverage existing power generation assets and operate the power plants as integrated electric generation systems. This allows us to achieve significant operating synergies and efficiencies in fuel procurement, power marketing, and operations and maintenance. The new plants we will bring on line will be predominantly natural gas-fired facilities, both combined-cycle base load plants and simple-cycle peakers, using state of the art, highly efficient and environmentally friendly gas turbine generator technology.

- *Acquisition of power plants.* Our strategy is to acquire power generating facilities that meet our stringent acquisition criteria and provide significant potential for revenue, cash flow and earnings growth, and that provide the opportunity to enhance the operating efficiencies of the plants. We have significantly expanded and diversified our project portfolio through numerous acquisitions of power generation facilities to date.

- *Enhancement of existing power projects' performance and efficiency.* We continually seek to maximize the power generation potential of our operating assets and to minimize our operating and maintenance expenses and fuel costs. This will become even more significant as our portfolio of power generation facilities expands to 86 power plants with a net capacity of 26,232 megawatts after completion of our new projects currently under construction. We focus on operating our plants as an integrated system of power generation, which enables us to minimize costs and maximize operating efficiencies. We believe that achieving and maintaining a low cost of production will be increasingly important to compete effectively in the power generation industry.

Our strategy is to become the most profitable generator by (1) achieving the low-cost position in the industry by applying our fully integrated areas of expertise to the cost-effective development, construction, financing, fueling, and operation of the most modern and efficient power generation facilities and by achieving economies of scale in general and administrative support costs, and (2) enhancing the value of the power we generate in the marketplace (a) by operating our plants as a system, (b) by geographic deployment of marketing specialists to sell directly to load-serving entities and, to the extent allowable, to industrial customers, in each of the markets in which we participate, (c) by offering load-following and other ancillary services to our customers, and (d) by providing effective marketing, risk management and asset optimization activities through our CES organization. This approach uses our expertise in design, engineering, procurement, finance, construction management, fuel and resource acquisition, operations and power marketing, which we believe provides us with a competitive advantage. Although not a core aspect of our business, we may enter into contracts for the sale or purchase of power or gas in markets where we presently do not have generation assets to establish relationships with customers and gain market experience where we expect to have generation assets in the future. We are also evaluating various relationships with potential partners to strengthen our ability to conduct risk management activities.

Our financing strategy is to achieve an investment grade credit and bond rating from the major rating agencies within the next few years. We intend to focus on various debt and sale-leaseback financings for our operating plants with a goal of retaining maximum system operating flexibility. The availability of capital at attractive terms will be a key requirement to enable us to meet our strategic objectives. Our risk management strategy, over time, is to hedge approximately two-thirds of our spark spread exposure in symmetry with our target debt-to-capitalization ratio. Spark spread is the margin between the value of the electricity sold and the cost of fuel to generate that electricity. Our fuel strategy is to produce from our own reserves about 25% of our fuel consumption needs as a natural hedge against gas price volatility, while providing a secure and reliable source of fuel and lowering our fuel costs over time.

COMPETITION

The power generation industry is characterized by intense competition, and we encounter competition from utilities, industrial companies and other independent power producers in the development, acquisition and operation of power generation facilities. In recent years, there has been increasing competition in an effort to obtain power sales agreements, and this competition has contributed to a reduction in electricity prices in certain markets. In addition, many states are implementing or considering regulatory initiatives designed to increase competition in the domestic power generation industry and increase access to electric utilities' transmission and distribution systems for independent power producers and electricity consumers. This changing environment will help create opportunities to compete for new customers and profits.

We believe that although the domestic power industry is undergoing consolidation and that, although acquisition opportunities are available, we are likely to confront significant competition for attractive acquisition opportunities. We may also be constrained in pursuing these alternatives by our access to capital at reasonable rates. This competition has put pressure on electric utilities to lower their costs, including the cost of purchased electricity, and increasing competition in the supply of electricity in the future will increase this pressure. See "Item 1 — Business — Recent Developments — California Power Market." Achieving and maintaining a low cost of production, including managing fuel costs, will be increasingly important to compete effectively in the power generation industry. We believe that our vertically integrated low cost approach to power generation gives us a competitive advantage within our industry.

RECENT DEVELOPMENTS

Construction Program — Following a comprehensive review of our power plant development program, we announced in January 2002 the adoption of a revised capital expenditure program, contemplating the completion during 2002 and 2003 of 27 power projects (representing 15,200 MW) currently under construction. Three of these projects have subsequently achieved full or partial commercial operations, the Magic Valley Generating Station, the Gilroy Peaking Energy Center and the Aries Power Project. Construction of an additional 34 advanced-stage development projects (representing 15,100 MW) will be placed on "hot standby" following completion of advanced development activities pending further review, reducing previously forecasted 2002 capital spending by as much as $2 billion. Construction of these advanced stage development projects is expected to proceed when there is marked need for additional generating resources at prices that will allow us to meet our established investment criteria, and when capital is available to us on attractive terms. Moreover, our entire construction program is flexible and subject to continuing review and revision based upon such criteria.

On March 12, 2002, we announced a new turbine program that reduces previously forecasted capital spending by approximately $1.2 billion in 2002 and $1.8 billion in 2003. The revision includes adjusted timing of turbine delivery and related payment schedules and also cancellation orders. As a result of the cancellation, we will record a pre-tax charge of $161 million in the first quarter of 2002.

Financing — On December 26, 2001, we completed an offering of $1 billion in aggregate principal amount of 4% Convertible Senior Notes Due 2006 ("Convertible Senior Notes") issued directly by Calpine. On each of December 31, 2001, and January 3, 2002, we sold an additional $100 million in aggregate principal amount of these Convertible Senior Notes, pursuant to partial exercises of a $200 million option to purchase additional Convertible Senior Notes granted to the initial purchaser. As a result of these additional closings, the initial purchaser's option was exercised in full and an aggregate principal amount of $1.2 billion of Convertible Senior Notes was issued by Calpine. Proceeds from these offerings will be used to retire our Zero-Coupon Convertible Debentures Due April 30, 2021, ("Zero Coupons"), either in open-market purchases, negotiated transactions or upon exercise by holders of a put option in April 2002, and for general corporate purposes.

From December 2001 through February 2002 we repurchased $314.5 million in aggregate principal amount of our Zero Coupons in open-market purchases.

In March 2002 we closed a new $1.6 billion secured credit facility. The $1.6 billion includes a new $1.0 billion revolving credit facility expiring on May 24, 2003, and a new two-year $600 million loan that will be available upon satisfaction of certain conditions. We also amended our existing $400 million revolving credit facility. The security for these facilities includes Calpine's interests in its natural gas properties, the Saltend power plant in the U.K. and Calpine's equity investment in nine U.S. power plants. The proceeds of the borrowings will be used to finance Calpine's capital expenditures and, subject to limits in Calpine's existing bond indentures, for other general corporate purposes. The lead banks in the new credit facility are The Bank of Nova Scotia, Citibank, Bank of America, Bayerische Landesbank Girozentrale, Credit Suisse First Boston, Deutsche Bank, The Toronto-Dominion Bank and ING Barings.

The Enron bankruptcy has created significant financial uncertainty in the power generation sector. On December 14, 2001, Moody's Investors Service ("Moody's") downgraded our long-term debt from Baa3 (its lowest investment grade rating) to Ba1 (its highest non-investment grade rating) after reviewing our near-term cash flow, liquidity sources and financial flexibility. We remain on credit watch with negative implications at Moody's. In addition, on December 19, 2001, Fitch, Inc. ("Fitch") downgraded our long-term debt from BBB– (its lowest investment grade rating) to BB+ (its highest non-investment grade rating). On March 12, 2002, Fitch further downgraded our senior unsecured debt to BB. On March 25, 2002, Standard & Poor's downgraded our corporate credit rating from BB+ to BB and our senior unsecured debt from BB+

to B+. Many other issuers in the power generation sector have also been downgraded by one or more of the ratings agencies during this period. As described above, we have raised funds in both the capital market and the bank credit market during this period of uncertainty, and we continue to believe that Calpine has adequate liquidity and access to capital to support its needs.

Enron Bankruptcy — On December 2, 2001, Enron Corp. ("Enron"), a significant customer accounting for 22% of our 2001 revenue, filed for reorganization under Chapter 11 of the United States Bankruptcy Code. As previously reported, we had entered into a master netting agreement with Enron on November 14, 2001, and had decreased our trading activity with Enron for several months prior to its bankruptcy filing. Based on legal analysis of our netting arrangements, we believe that we have no net collection exposure to Enron. See Management's Discussion and Analysis of Financial Condition and Results of Operation — Liquidity and Capital Resources for a further discussion of the Enron bankruptcy and netting agreement.

California Long-Term Supply Contracts — On December 11, 2001, Calpine announced that it was meeting with officials from the State of California at their request to discuss whether, and if so how, the long-term contracts with DWR could be modified. No definitive modifications have been agreed to and the discussions have been ongoing.

However, we currently have a dispute with DWR concerning payment of the capacity payment on the 495-megawatt peaking contract dated February 28, 2001. The contract provides that CES may earn a capacity payment by committing to supply electricity to DWR from a source other than the peaker units designated in the contract either through substitution of those designated units or by providing replacement energy. DWR has made certain assertions challenging CES' right to substitute units or provide replacement energy and has withheld capacity payments in the amount of $9.5 million since December 2001. The resolution of this dispute is part of the ongoing discussions regarding modifications to the contracts.

On February 25, 2002, both the California Public Utilities Commission ("CPUC") and the California Electric Oversight Board filed complaints under Section 206 of the Federal Power Act with the Federal Energy Regulatory Commission ("FERC") (EL02-60-000 and EL02-62-000, respectively) alleging that the prices and terms of the long-term contracts with the California Department of Water Resources ("DWR") are unjust and unreasonable and counter to the public interest. Calpine is a respondent and the four long-term contracts entered into by Calpine are subject to the complaint. The FERC has noticed this proceeding and responsive filings are due from the respondents on or before March 22, 2002. Calpine believes that the complaints are without merit and intends to defend its position vigorously.

On March 6, 2002, in accordance with the state legislation that authorized DWR to enter into the long-term power contracts, the CPUC issued a Rate Agreement, which dedicates a portion of the retail rate paid by electricity customers of the California investor-owned utilities to a fund to pay holders of bonds to be issued by DWR and to a fund to pay electricity suppliers such as Calpine. The proceeds from those bonds will be used in part to fund the Electric Power Fund established by the state legislation authorizing DWR to enter into long-term power contracts with the power suppliers whose recourse in the event of a default by DWR is to the Electric Power Fund. Proceeds from the bonds will also be used to repay the state of California General Fund. The bonds have not been issued, but representatives of the State have indicated that the bonds should be issued in the near future.

FERC Investigation into California Wholesale Markets — On February 13, 2002, FERC initiated an investigation of potential manipulation of electric and natural gas prices in the western United States. This investigation was initiated as a result of allegations that Enron and others, through their affiliates, used its market position to distort electric and natural gas markets in the West. The scope of the investigation is to consider whether, as a result of any manipulation in the short-term markets for electric energy or natural gas or other undue influence on the wholesale markets by any party since January 1, 2000, the rates of the long-term contracts subsequently entered into in the West are potentially unjust and unreasonable. FERC has stated that it may use the information gathered in connection with the investigation to determine how to proceed on any existing or future complaint brought under Section 206 of the Federal Power Act involving long-term power contracts entered into in the West since January 1, 2000, or to initiate a Federal Power Act Section 206 or Natural Gas Act Section 5 proceeding on its own initiative.

Securities Class Action Lawsuits. Over the past several weeks, five shareholder lawsuits have been filed against Calpine and certain of its officers in the United States District Court, Northern District of California. The action captioned *Weisz vs. Calpine Corp., et al.*, filed March 11, 2002, is a purported class action on behalf of purchasers of Calpine stock between March 15, 2001 and December 13, 2001. The four other actions, captioned *Local 144 Nursing Home Pension Fund vs. Calpine Corp., Lukowski vs. Calpine Corp., Hart vs. Calpine Corp.,* and *Atchison vs. Calpine Corp.*, were filed between March 18, 2002 and March 26, 2002. The complaints in these four actions are virtually identical, and each was filed by the same law firm, in conjunction with other law firms as co-counsel. All four lawsuits are purported class actions on behalf of purchasers of Calpine's securities between January 5, 2001 and December 13, 2001.

The complaints in these five actions allege that, during the purported class periods, defendants Calpine and certain senior executives issued false and misleading statements about Calpine's financial condition in violation of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, as well as Rule 10b-5. These actions seek an unspecified amount of damages, in addition to other forms of relief. We expect that these actions, as well as any related actions that may be filed in the future, will be consolidated by the court into a single securities class action. We consider the lawsuits to be without merit, and we intend to defend vigorously against these allegations.

Public Utilities Commission of the State of California v. Sellers of Long Term Contracts to the California Department of Water Resources; California Electricity Oversight Board v. Sellers of Long Term Contracts to the California Department of Water Resources. In February 2002, both the California Public Utilities Commission and the California Electric Oversight Board filed complaints under Section 206 of the Federal Power Act with the Federal Energy Regulatory Commission (FERC) (EL02-60-000 and EL02-62-000, respectively) alleging that the prices and terms of the long-term contracts with the California Department of Water Resources (DWR) are unjust and unreasonable and counter to the public interest. Calpine Energy Services, L.P. (CES) is a respondent and the four long-term contracts entered into between CES and DWR are subject to the complaint. *(see, Risk Factors — California Long-Term Supply Agreements)* The FERC has noticed this proceeding and responsive pleadings were due from the respondents on or before March 22, 2002. Calpine believes that the complaints are without merit and intends to defend its position vigorously.

Litigation — On March 5, 2002, Calpine sued Automated Credit Exchange ("ACE") in the Superior Court of the State of California for the County of Alameda, for negligence and breach of contract to recover reclaim trading credits, a form of emission reduction credits that should have been held in Calpine's account with U.S. Trust Company (US Trust). ACE is a broker in emission reduction credits based in Pasadena, California. Calpine had paid ACE for Nitrogen oxide (NOx) coastal credits that were to be purchased by ACE and held by US Trust. The credits were to be held by US Trust pursuant to a Credit Holding Agreement, which provided, among other things, that US Trust was to hold the credits until receiving instructions from ACE to disburse the Credits. ACE had agreed that (i) upon prior written instruction from Calpine, to instruct US Trust to take such actions as may be directed by Calpine to disburse the credits held in escrow pursuant to the Credit Holding Agreement and (ii) not to take any action, or otherwise instruct US Trust to take any action, concerning the credits held in escrow pursuant to the Credit Holding Agreement without prior written instruction from Calpine.

DESCRIPTION OF FACILITIES

At March 20, 2002, Calpine had interests in 64 power generation facilities representing 12,090 megawatts of net capacity. Of these 64 projects, 45 are gas-fired power plants with a net capacity of 11,240 megawatts, and 19 are geothermal power generation facilities with a net capacity of 850 megawatts. We also have 22 gas-fired projects and 2 project expansions currently under construction with a net capacity of 14,142 megawatts, and have 34 projects in advanced development with a net capacity of 15,100 megawatts. Construction of these advanced development projects will proceed if and when market fundamentals are sound, our return on investment criteria are expected to be met, and financing is available on attractive terms. Each of the power generation facilities currently in operation produces electricity for sale to a utility, other third-party end user, or to an intermediary such as a trading company. Thermal energy produced by the gas-fired cogeneration facilities is sold to governmental and industrial users.

The gas-fired and geothermal power generation projects in which we have an interest produce electricity and thermal energy that are sold pursuant to long-term power sales agreements or into the spot market. Revenue from a power sales agreement usually consists of two components: energy payments and capacity payments. Energy payments are based on a power plant's net electrical output, and payment rates are typically either at fixed rates or indexed to fuel costs. Capacity payments are based on a power plant's net electrical output and/or its available capacity. Energy payments are earned for each kilowatt-hour of energy delivered, while capacity payments, under certain circumstances, are earned whether or not any electricity is scheduled by the customer and delivered.

Upon completion of our projects under construction, we will provide operating and maintenance services for 82 of the 86 power plants in which we have an interest. Such services include the operation of power plants, geothermal steam fields, wells and well pumps, gas fields, gathering systems and gas pipelines. We also supervise maintenance, materials purchasing and inventory control, manage cash flow, train staff and prepare operating and maintenance manuals for each power generation facility that we operate. As a facility develops an operating history, we analyze its operation and may modify or upgrade equipment or adjust operating procedures or maintenance measures to enhance the facility's reliability or profitability. These services are sometimes performed for third parties under the terms of an operating and maintenance agreement pursuant to which we are generally reimbursed for certain costs, paid an annual operating fee and may also be paid an incentive fee based on the performance of the facility. The fees payable to us may be subordinated to any lease payments or debt service obligations of financing for the project.

In order to provide fuel for the gas-fired power generation facilities in which we have an interest, natural gas reserves are acquired or natural gas is purchased from third parties under supply agreements. We attempt to manage a gas-fired power facility's fuel supply so that we protect the plant's spark spread — the margin between the value of the electricity sold and the cost of fuel to generate that electricity.

We currently hold interests in geothermal leaseholds in Lake and Sonoma Counties in northern California ("The Geysers") that produce steam that is supplied to geothermal power generation facilities owned by us for use in producing electricity.

Certain power generation facilities in which we have an interest have been financed primarily with project financing that is structured to be serviced out of the cash flows derived from the sale of electricity and thermal energy produced by such facilities and provides that the obligations to pay interest and principal on the loans are secured almost solely by the capital stock or partnership interests, physical assets, contracts and/or cash flow attributable to the entities that own the facilities. The lenders under non-recourse project financing generally have no recourse for repayment against us or any of our assets or the assets of any other entity other than foreclosure on pledges of stock or partnership interests and the assets attributable to the entities that own the facilities. Increasingly, our plan has been to refinance project-specific construction financing with long-term capital market financing after construction projects enter commercial operation.

Substantially all of the power generation facilities in which we have an interest are located on sites which we own or are leased on a long-term basis. See "Item 2. Properties."

Set forth below is certain information regarding our operating power plants and plants under construction as of March 20, 2002.

	Number of Plants	Megawatts Baseload Capacity	Peaking Capacity	Calpine Net Interest Baseload	Calpine Net Interest Peaking
In operation					
Geothermal power plants	19	850	850	850	850
Gas-fired power plants	45	10,354	12,653	9,038	11,240
Under construction					
New facilities	22	12,223	14,209	11,683	13,589
Expansion projects (two)	—	365	553	365	553
	86	23,792	28,265	21,936	26,232

Operating Power Plants

Power Plant	Country, US State or Can. Province	Baseload Capacity (MW)	Peaking Capacity (MW)	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)	Calpine Net Interest Peaking (MW)	2001 Generation MWh
Geothermal Power Plants							
Sonoma County (12 plants)	CA	512.0	512.0	100.0%	512.0	512.0	3,789,094
Lake County (2 plants)	CA	145.0	145.0	100.0%	145.0	145.0	1,061,720
Calistoga	CA	73.0	73.0	100.0%	73.0	73.0	536,906
Sonoma	CA	53.0	53.0	100.0%	53.0	53.0	385,647
West Ford Flat	CA	27.0	27.0	100.0%	27.0	27.0	228,679
Bear Canyon	CA	20.0	20.0	100.0%	20.0	20.0	150,149
Aidlin	CA	20.0	20.0	100.0%	20.0	20.0	144,061
Total Geothermal Power Plants (19)		850.0	850.0		850.0	850.0	6,296,256
Gas-Fired Power Plants							
Saltend Energy Center	UK	1,200.0	1,200.0	100.0%	1,200.0	1,200.0	3,326,988
Broad River Energy Center	SC	—	840.0	100.0%	—	840.0	429,110
Pasadena Power Plant	TX	751.0	787.0	100.0%	751.0	787.0	4,754,618
Magic Valley Generating Station	TX	687.0	750.0	100.0%	687.0	750.0	—
South Point Energy Center	CA	526.0	555.0	100.0%	526.0	555.0	1,904,851
Los Medanos Energy Center	CA	493.0	555.0	100.0%	493.0	555.0	1,099,577
Sutter Energy Center	AZ	516.0	547.0	100.0%	516.0	547.0	1,656,203
Lost Pines 1 Energy Center	TX	522.0	545.0	50.0%	261.0	272.5	1,006,008
Westbrook Energy Center	ME	487.0	525.0	100.0%	487.0	525.0	2,464,070
Hidalgo Energy Center	TX	502.0	502.0	78.5%	394.1	394.1	2,164,502
Texas City Power Plant	TX	465.0	471.0	100.0%	465.0	471.0	3,162,396
RockGen Energy Center	WI	—	460.0	100.0%	—	460.0	112,584
Clear Lake Power Plant	TX	335.0	412.0	100.0%	335.0	412.0	2,574,481
Aries Power Project	MO	516.0	591.0	50.0%	258.0	295.5	—
Rumford Power Plant	ME	237.0	251.0	100.0%	237.0	251.0	1,746,382
Hog Bayou Energy Center	AL	246.6	246.6	100.0%	246.6	246.6	124,490
Tiverton Power Plant	RI	240.0	240.0	100.0%	240.0	240.0	1,764,918
Gordonsville Power Plant	VA	233.0	238.0	50.0%	116.5	119.0	81,900
Pine Bluff Energy Center	AR	213.3	213.3	100.0%	213.3	213.3	447,000

Power Plant	Country, US State or Can. Province	Baseload Capacity (MW)	Peaking Capacity (MW)	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)	Calpine Net Interest Peaking (MW)	2001 Generation MWh
Lockport Power Plant	NY	177.0	198.0	11.4%	20.1	22.5	176,928
Channel Energy Center (simple-cycle)	TX	190.0	190.0	100.0%	190.0	190.0	474,000
DePere Energy Center	WI	—	180.0	100.0%	—	180.0	142,559
Morris Power Plant	IL	155.0	177.5	86.0%	134.0	146.4	507,844
Bayonne Power Plant(1)	NJ						35
Dighton Power Plant	MA	162.0	168.0	100.0%	162.0	168.0	713,457
Androscoggin Energy Center	ME	160.0	160.0	32.3%	51.7	51.7	250,236
Auburndale Power Plant	FL	143.0	153.0	100.0%	143.0	153.0	1,046,265
Grays Ferry Power Plant	PA	143.0	148.0	40.0%	57.2	59.2	273,486
Gilroy Peaking Energy Center	CA	—	135.0	100.0%	—	135.0	—
Gilroy Power Plant	CA	112.0	131.0	100.0%	112.0	131.0	972,343
Pryor Power Plant	OK	109.0	124.0	80.0%	87.2	99.2	312,419
Sumas Power Plant	WA	120.0	122.0	0.1%	0.1	0.1	550,837
Parlin Power Plant	NJ	89.0	118.0	80.0%	71.2	94.4	387,456
King City Power Plant	CA	103.0	115.0	100.0%	103.0	115.0	853,059
Kennedy International Airport Power Plant (“KIAC”)	NY	95.0	105.0	100.0%	95.0	105.0	504,186
Pittsburg Power Plant	CA	64.0	71.0	100.0%	64.0	71.0	442,273
Newark Power Plant	NJ	47.0	58.0	80.0%	37.6	46.4	393,262
Bethpage Power Plant	NY	52.0	53.7	100.0%	52.0	53.7	344,429
Greenleaf 1 Power Plant	CA	50.0	50.0	100.0%	50.0	50.0	392,868
Greenleaf 2 Power Plant	CA	50.0	50.0	100.0%	50.0	50.0	342,580
Whitby Cogeneration	ON	50.0	50.0	50.0%	25.0	25.0	49,793
King City Energy Center	CA	—	45.0	100.0%	—	45.0	—
Stony Brook Power Plant	NY	36.0	40.0	100.0%	36.0	40.0	247,044
Watsonville Power Plant	CA	29.0	30.0	100.0%	29.0	30.0	208,743
Agnews Power Plant	CA	26.5	28.6	100.0%	26.5	28.6	220,749
Philadelphia Water Project	PA	22.0	23.0	66.4%	14.6	15.3	2,323
Total Gas-Fired Power Plants (45)		10,354.4	12,652.7		9,037.7	11,239.5	38,629,252
Total Operating Power Plants (64)		11,204.4	13,502.7		9,887.7	12,089.5	44,925,508
Consolidated Projects		9,805.4	11,995.7		9,359.1	11,516.5	43,542,293
Equity (Unconsolidated) Projects		1,399.0	1,507.0		528.6	573.0	1,383,215

(1) We sold our 7.5% interest in this facility on March 12, 2001.

Projects Under Construction

Power Plant	Fuel	Country, US State or Can. Province	Baseload Capacity (MW)	Peaking Capacity (MW)	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)	Calpine Net Interest Peaking (MW)
Projects Under Construction							
Acadia Energy Center	Gas	LA	1,080.0	1,239.0	50.0%	540.0	619.5
Oneta Energy Center	Gas	OK	960.3	1,137.8	100.0%	960.3	1,137.8
Freestone Energy Center	Gas	TX	1,002.8	1,051.6	100.0%	1,002.8	1,051.6
Deer Park Energy Center	Gas	TX	773.0	1,007.0	100.0%	773.0	1,007.0
Delta Energy Center	Gas	CA	798.0	874.0	100.0%	798.0	874.0
Baytown Power Plant	Gas	TX	704.0	834.0	100.0%	704.0	834.0
Decatur Energy Center	Gas	AL	659.0	794.0	100.0%	659.0	794.0
Morgan Energy Center	Gas	AL	660.0	790.0	100.0%	660.0	790.0
Hillabee Energy Center	Gas	AL	710.0	770.0	100.0%	710.0	770.0
Pastoria Energy Center	Gas	CA	750.0	750.0	100.0%	750.0	750.0
Hermiston Power Project	Gas	OR	530.0	630.0	100.0%	530.0	630.0
Osprey Energy Center	Gas	FL	530.0	590.0	100.0%	530.0	590.0
Washington Parish Energy Center	Gas	LA	509.0	565.0	100.0%	509.0	565.0
Ontelaunee Energy Center	Gas	PA	511.0	541.0	100.0%	511.0	541.0
Corpus Christi Energy Center	Gas	TX	522.7	522.7	100.0%	522.7	522.7
Carville Energy Center	Gas	LA	522.7	522.7	100.0%	522.7	522.7
Zion Energy Center	Gas	IL	—	495.0	100.0%	—	495.0
Channel Energy Center (combined-cycle)*	Gas	TX	365.0	438.0	100.0%	365.0	438.0
Calgary Energy Centre	Gas	AB	250.0	300.0	100.0%	250.0	300.0
Santa Rosa Energy Center	Gas	FL	252.0	252.0	100.0%	252.0	252.0
Island Cogeneration	Gas	BC	250.0	250.0	100.0%	250.0	250.0
Goldendale Energy Center	Gas	WA	248.0	248.0	100.0%	248.0	248.0
Auburndale Expansion*	Gas	FL	—	115.0	100.0%	—	115.0
Yuba City Energy Center	Gas	CA	—	45.0	100.0%	—	45.0
Total Projects Under Construction (22)			12,587.5	14,761.8		12,047.5	14,142.3

* Expansion projects not included in total of 86 projects in which Calpine has an interest.

ACQUISITIONS OF POWER PROJECTS AND PROJECTS UNDER CONSTRUCTION

We have extensive experience in the development and acquisition of power generation projects. We have historically focused principally on the development and acquisition of interests in gas-fired and geothermal power projects, although we may also consider projects that utilize other power generation technologies. We have significant expertise in a variety of power generation technologies and have substantial capabilities in each aspect of the development and acquisition process, including design, engineering, procurement, construction management, fuel and resource acquisition and management, power marketing, financing and operations.

Acquisitions

We will consider the acquisition of an interest in operating projects as well as projects under development where we would assume responsibility for completing the development of the project. In the acquisition of power generation facilities, we generally seek to acquire 100% ownership of facilities that offer us attractive opportunities for earnings growth, and that permit us to assume sole responsibility for the operation and maintenance of the facility. In evaluating and selecting a project for acquisition, we consider a variety of factors, including the type of power generation technology utilized, the location of the project, the terms of any existing power or thermal energy sales agreements, gas supply and transportation agreements and wheeling agreements, the quantity and quality of any geothermal or other natural resource involved, and the actual condition of the physical plant. In addition, we assess the past performance of an operating project and prepare financial projections to determine the profitability of the project.

Although our preference is to own 100% of the power plants we acquire or develop, there are situations when we take less than 100% ownership. Reasons why we may take less than a 100% interest in a power plant may include, but are not limited to: (a) our acquisitions of other independent power producers such as Cogeneration Corporation of America in 1999 and SkyGen Energy LLC in 2000 in which minority interest projects were included in the portfolio of assets owned by the acquired entities (Grays Ferry Power Plant (40% now owned by Calpine) and Androscoggin Energy Center (32.3% now owned by Calpine), respectively); (b) opportunities to co-invest with non-regulated subsidiaries of regulated electric utilities, which under PURPA are restricted to 50% ownership of cogeneration qualifying facilities — such as our investment in Gordonsville Power Plant (50% owned by Calpine and 50% owned by Edison Mission Energy, which is wholly-owned by Edison International Company); and (c) opportunities to invest in merchant power projects with partners who bring marketing, funding, permitting or other resources that add value to a project. An example of this is Acadia Energy Center, which is under construction in Louisiana (50% owned by Calpine and 50% owned by Cleco Midstream Resources, an affiliate of Cleco Corporation).

Projects Under Construction

The development and construction of power generation projects involves numerous elements, including evaluating and selecting development opportunities, designing and engineering the project, obtaining power sales agreements in some cases, acquiring necessary land rights, permits and fuel resources, obtaining financing, procuring equipment and managing construction. We intend to focus primarily on opportunities where we are able to capitalize on our expertise in implementing an innovative and fully integrated approach to project development in which we control the entire development process. Utilizing this approach, we believe that we are able to enhance the value of our projects throughout each stage of development in an effort to maximize our return on investment.

Subject to the constraints mentioned above under "Recent Developments — Construction Program", we are pursuing the development of highly efficient, low-cost power plants to provide competitively priced and environmentally friendly power to electricity markets. We intend to sell all or a portion of the power generated by such plants into the competitive market through a portfolio of short, medium and long-term power sales agreements.

Acadia Energy Center. On March 6, 2000, we announced that we entered into a partnership agreement with Cleco Midstream Resources, an affiliate of Pineville, Louisiana-based Cleco Corporation, to build, own and operate the 1,239-megawatt natural gas-fired Acadia Energy Center near Eunice, Louisiana. We have a 50% net interest in this facility. Construction began in mid 2000 and commercial operation is expected in mid 2002. On October 20, 2000, we jointly announced with Cleco Corporation the signing of a 20-year contract with Aquila Energy, a wholly owned subsidiary of UtiliCorp United, for 580 megawatts of the output of the Acadia Energy Center. Under terms of a tolling agreement, starting July 1, 2002, Aquila Energy will supply the natural gas needed to generate 580 megawatts of electricity and will own and market the produced power.

Oneta Energy Center. On July 20, 2000, we acquired the development rights to construct, own and operate the Oneta Energy Center from Panda Energy, International, Inc. Oneta is a 1,138-megawatt, natural gas-fired energy center under construction in Coweta, Oklahoma, southeast of Tulsa. We anticipate that the first phase of the Oneta Energy Center will commence commercial operation in mid 2002.

Freestone Energy Center. On June 15, 2000, we announced that we acquired the rights to develop, build, own and operate the Freestone Energy Center from New Orleans, Louisiana-based Entergy Corp. Freestone is a 1,052-megawatt, natural gas-fired energy center located in Freestone County, Texas, near

Fairfield, about 80 miles southeast of Dallas. Construction commenced in the summer of 2000 and commercial operation is expected to begin in the summer of 2002.

Deer Park Energy Center. In March 2001 we announced plans to build, own and operate a 1,007-megawatt, natural gas-fired energy center in Deer Park, Texas. The proposed Deer Park Energy Center will supply steam to Shell Chemical Company, and electric power generated at the facility will be sold on the wholesale market. Construction began in mid-2001. The first, second and third phases of the project are expected to begin commercial operation in February 2003, August 2003, and June 2004, respectively.

Delta Energy Center. In February 1999 we, together with Bechtel Enterprises, announced plans to develop an 874-megawatt, natural gas-fired cogeneration energy center in Pittsburg, California. In November 2001 we acquired Bechtel's interest in the project. The Delta Energy Center will provide steam and electricity to the nearby Dow Chemical Company facility and market the excess electricity into the California power market. Construction began in April 2000 and we expect commercial operation to commence in the spring of 2002.

Baytown Power Plant. In October 1999 we announced plans to build, own and operate an 834-megawatt, natural gas-fired cogeneration power plant at Bayer Corporation's chemical facility in Baytown, Texas. The Baytown Power Plant will supply Bayer with all of its electric and steam requirements for 20 years and market excess electricity into the Texas wholesale power market. Construction commenced in early 2000 and commercial operation is expected to commence in the summer of 2002.

Decatur Energy Center. On February 2, 2000, we announced plans to build, own and operate a 794-megawatt, natural gas-fired cogeneration energy center at Solutia Inc.'s Decatur, Alabama chemical facility. Under a 20-year agreement, Solutia will lease a portion of the facility to meet its electricity needs and purchase its steam requirements from us. Excess power from the facility will be sold into the Southeastern Wholesale Power Market under a variety of short, medium and long-term contracts. We will also build a new intrastate natural gas pipeline to fuel the energy center. Construction began in September 2000 and commercial operation for the first phase is scheduled for mid 2002.

Morgan Energy Center. On June 27, 2000, we announced plans to build, own and operate a natural gas-fired cogeneration energy center at the BP Amoco chemical facility in Decatur, Alabama. The Morgan Energy Center will generate approximately 790 megawatts of electricity in addition to supplying steam for BP Amoco's facility. Construction began in September 2000 and we expect commercial operation to begin in mid 2003.

Hillabee Energy Center. On February 24, 2000, we announced plans to build, own and operate the Hillabee Energy Center, a 770-megawatt, natural gas-fired cogeneration facility in Tallapoosa County, Alabama. Construction began in mid-2001 and we expect commercial operation of the facility will commence in late 2003.

Pastoria Energy Center. In April 2001 we acquired the rights to develop the 750-megawatt Pastoria Energy Center, a combined-cycle project planned for Kern County, California. Construction began in the summer of 2001 and commercial operation is scheduled to begin in the fall of 2003.

Hermiston Power Project. On January 28, 2000, we acquired the development rights for the Hermiston Power Project, a 630-megawatt, natural gas-fired cogeneration power facility located near Hermiston, Oregon. Construction commenced in the summer of 2000 and we anticipate that commercial operation of the facility will commence in the summer of 2002.

Osprey Energy Center. On January 11, 2000, we announced plans to build, own and operate the Osprey Energy Center, a 590-megawatt, natural gas-fired cogeneration energy center near the city of Auburndale, Florida. On February 12, 2001, the Florida Public Service Commission approved the application for the facility, which will be built adjacent to our existing power facility, the Auburndale Power Plant. Construction commenced in the fall of 2001 and commercial operation of the facility is scheduled to begin in the fall of 2003. Upon commercial operation, the Osprey Energy Center will supply electric power to Tampa, Florida-based Seminole Electric Cooperative, Inc. ("Seminole") to help meet Seminole's member systems' power needs for a period of 17 years.

Washington Parish Energy Center. On January 26, 2001, we announced the acquisition of the development rights from Cogentrix, an independent power company based in North Carolina, for the 565-megawatt Washington Parish Energy Center, located near Bogalusa, Louisiana. We are managing construction of the facility, which began in January 2001, and will operate the facility when it enters commercial operation in mid 2004.

Ontelaunee Energy Center. In June 1999 we announced that we had acquired the rights to develop a 541-megawatt, natural gas-fired energy center in Ontelaunee Township in eastern Pennsylvania. Construction began in July 2000 and commercial operation is estimated to commence in mid 2002. Output from the Ontelaunee Energy Center will be sold into the Pennsylvania/New Jersey/Maryland power pool and pursuant to bilateral contracts.

Corpus Christi Energy Center. The Corpus Christi Energy Center is a 523-megawatt combined-cycle, cogeneration energy center located in Corpus Christi, Texas. Construction began in June 2000 and we expect commercial operation to begin in July 2002. In March 1999 a long-term energy services agreement was executed with CITGO Refining and Chemicals Company, L.P. ("CITGO") under which CITGO will purchase from the Corpus Christi Energy Center all of the steam and electricity that it requires but does not internally generate at its Corpus Christi refinery.

Carville Energy Center. The Carville Energy Center is a 523-megawatt combined-cycle, cogeneration energy center located in St. Gabriel, Louisiana. Construction of the facility began in October 2000 and commercial operation is expected to commence in November 2002. On December 28, 1999, a long-term energy services agreement was executed with Cos-Mar Inc. ("Cos-Mar") under which Cos-Mar will purchase from the Carville Energy Center all of the steam and electric power (if allowed under applicable regulations) that it requires but does not internally generate at its St. Gabriel chemical plant.

Zion Energy Center. The Zion Energy Center is a 495-megawatt simple-cycle facility located in Zion, Illinois. Construction began in August 2001 and commercial operation for the first phase is expected to commence in August 2002. In December 2000 and March 2001 contracts were executed for the long-term sale of capacity from the Zion Energy Center.

Channel Energy Center (combined-cycle). In October 1999 we announced we had executed a letter of intent that gave us the exclusive right to negotiate with LYONDELL-CITGO Refining LP to build, own and operate a 628-megawatt, natural gas-fired cogeneration energy center at the LYONDELL-CITGO refinery in Houston, Texas. The Channel Energy Center will supply all of the electricity and steam requirements for 20 years to the refinery. Construction began in early 2000, simple-cycle commercial operation (190 megawatts) commenced in the summer of 2001, and combined-cycle commercial operation (438 megawatts) is scheduled to begin in the spring of 2002.

Calgary Energy Centre. On April 20, 2000, we announced plans to construct the Calgary Energy Centre. Scheduled to begin commercial operation in the spring of 2003, the 300-megawatt, natural gas-fired, combined-cycle facility was the first independent power project announced in the Calgary area and represents our first investment in the Canadian power industry.

Santa Rosa Energy Center. The Santa Rosa Energy Center is a 252-megawatt combined-cycle energy center located near Pensacola, Florida. Construction began in September 2000 and commercial operation is expected to commence in June 2003.

Island Cogeneration. In September 2001 we acquired from Westcoast Energy a 250-megawatt, natural gas-fired cogeneration facility located near Campbell River, British Columbia on Vancouver Island. Construction began in September 1998 and we expect commercial operation to begin in the spring of 2002. Island Cogeneration will deliver electricity to BC Hydro under the terms of a 20-year agreement and will provide steam to Norske Skog for industrial processing under the terms of a 15-year contract.

Goldendale Energy Center. In April 2001 we acquired the rights to develop a 248-megawatt combined-cycle energy center located in Goldendale, Washington. Construction of the Goldendale Energy Center began in the spring of 2001 and commercial operation is expected to commence in the fall of 2002. Energy generated by the facility will be sold directly into the Northwest Power Pool.

Auburndale Expansion. On July 6, 2000, we announced the addition of 115 megawatts of peaking capacity to the natural gas-fired cogeneration facility located in Auburndale, Florida. Construction began in August 2001 and commercial operation is expected to commence in June 2002.

Yuba City Energy Center. In January 2002 construction began on this 45-megawatt project located adjacent to the Greenleaf 2 Power Plant in Yuba City, California. Upon commercial operation, which is scheduled for mid 2002, the Yuba City Energy Center, and other Calpine peaking facilities, will supply peaking power to DWR in accordance with a 20-year contract.

OIL AND GAS PROPERTIES

Montis Niger. In January 1997 we purchased Montis Niger, Inc., a gas production and pipeline company operating primarily in the Sacramento Basin in northern California, which we subsequently renamed Calpine Gas Company. Calpine Gas Company owns proven natural gas reserves and leasehold acreage, and operates an 80-mile pipeline delivering gas to our Greenleaf 1 and 2 Power Plants. We currently supply the majority of the fuel requirements for the Greenleaf 1 and 2 Power Plants.

Calpine Natural Gas Company. In October 1999 we purchased Sheridan Energy, Inc. ("Sheridan"), a natural gas exploration and production company operating in northern California and the Gulf Coast region, which we subsequently renamed Calpine Natural Gas Company ("CNGC"). CNGC's oil and gas properties are primarily natural gas and are located in strategic markets where we are developing low-cost natural gas supplies and proprietary pipeline systems in support of our natural gas-fired power plants.

Vintage Petroleum. In December 1999 we completed the acquisition of Vintage Petroleum, Inc.'s interest in the Rio Vista Gas Unit and related areas, representing primarily natural gas reserves located in the Sacramento Basin in northern California. Primarily as a result of this acquisition and the Sheridan acquisition, we own a 100% working interest in the Rio Vista Gas Unit and certain development acreage in northern California.

Western Gas Resources. On February 4, 2000, we acquired 100% of the stock of Western Gas Resources California ("Western") from Western Gas Resources, Inc. Western's assets include the 130-mile Steelhead natural gas pipeline and the remaining interest in the Sacramento River Gas System natural gas pipeline, now 100% owned by us.

Gulf of Mexico. In June 2000 we acquired an interest in the East Cameron, High Island and South Pelto fields in the Gulf of Mexico which included 10 producing wells and 5 drilling locations enhanced with 3-D seismic, three of which have already been successfully drilled.

Calpine Canada Natural Gas, Ltd. On July 5, 2000, we purchased Calgary-based Quintana Minerals Canada Corp., a natural gas exploration and production company, whose reserves are located in British Columbia, Alberta and Saskatchewan provinces in Canada. We subsequently changed its name to Calpine Canada Natural Gas, Ltd. ("CCNG"). The assets included interests in 1,300 wells.

Additionally, on November 15, 2000, we acquired TriGas Exploration Inc., of Calgary, Alberta, an exploration company focused on developing and producing gas reserves in south-central Alberta. We subsequently merged the company into CCNG. The assets include an interest in 74 producing wells located in the Acme, Lone Pine, Lone Pine South and Irricana fields, 48,000 net acres of undeveloped lands, two compression facilities, a 26.6% working interest in the Crossfield gas processing plant located near the fields, and a majority interest in 63 miles of pipeline that conduct the gas to two nearby gas-fired power generation facilities.

Colorado and Gulf Coast. In July 2000 we acquired natural gas assets in the Piceance Basin, Colorado and onshore Gulf Coast from a privately held Houston, Texas-based company. The assets included 126 producing wells, 79,000 acres of undeveloped lands, and 195 potential drilling locations with historical success rates of over 90 percent.

The Bayless Companies. On April 17, 2001, we acquired certain natural gas assets of The Bayless Companies for approximately $35.1 million. As part of the acquisition, certain individuals began employment with the Company. The reserves acquired are located in the western portion of the San Juan Basin in New Mexico and currently produce approximately 5.2 net million cubic feet equivalent per day ("mmcfe/d"), 100 percent of which is gas. We anticipate drilling additional development wells in the future on the 6,185 undeveloped acreage remaining at year end.

Encal Energy Ltd. ("Encal"). On April 19, 2001, we completed our merger with Encal, a Calgary, Alberta-based natural gas and petroleum exploration and development company. Encal shareholders received, in exchange for each share of Encal common stock, 0.1493 shares of Calpine common equivalent shares (called "exchangeable shares") of the Company's subsidiary, Calpine Canada Holdings Ltd. A total of 16,603,633 exchangeable shares were issued to Encal shareholders in exchange for all of the outstanding shares of Encal common stock. Each exchangeable share is exchangeable for one share of Calpine common stock. The aggregate value of the transaction was approximately US$1.1 billion, including the assumed indebtedness of Encal. The transaction was accounted for as a pooling-of-interests. Upon completion of the acquisition, we gained approximately 664 billion cubic feet equivalent of proved natural gas reserves, net of royalties. This transaction also provides access to firm gas transportation capacity from western Canada to California and the eastern U.S., and an accomplished management team capable of leading our business expansion in Canada. In addition, Encal had proved undeveloped acreage totaling approximately 1.2 million acres.

Michael Petroleum Corporation. On August 15, 2001, we acquired approximately 86% of the outstanding stock of Michael Petroleum Corporation ("MPC"), a natural gas exploration and production company, from various shareholders. The remaining 14% of outstanding stock was purchased on October 22, 2001, resulting in the Company owning 100% of MPC. The cash purchase price of the acquisition was $315.8 million plus assumed indebtedness of $54.5 million, and the acquisition was accounted for as a purchase. The MPC assets consisted of approximately 531 wells, producing approximately 33.5 net mmcfe/d, of which gas is 90 percent, and developed and non-developed acreage totaling approximately 82,590 net acres at December 31, 2001.

Whiting Petroleum Corporation. On December 14, 2001, we acquired certain natural gas assets of Whiting Petroleum Corporation and other minority partner interest owners for approximately $8 million. These certain assets are located in close proximity to The Bayless Companies property acquisition in the San Juan Basin of New Mexico completed in April 2001. Current production from this acquisition is approximately 1.7 mmcfe/d, and the Company anticipates future infield drilling on its existing 3,520 acres by year end 2002.

As a result of the Company's oil and gas acquisition and drilling program activity, equity equivalent net production was approximately 380 mmcfe/d at December 31, 2001, enough to fuel approximately 2,188 megawatts of our power plant fleet.

MARKETING, HEDGING, OPTIMIZATION, AND TRADING ACTIVITIES

Most of the electric power generated by our plants is transferred to our marketing and risk management unit, CES, which sells it to load-bearing entities (e.g., utilities and end users) and to other third parties (e.g., power trading and marketing companies). Because a sufficiently liquid market does not exist for electricity financial instruments (typically, exchange and over-the-counter traded contracts that net settle rather than entail physical delivery) at most of the locations where Calpine sells power, CES also enters into incremental physical purchase and sale transactions as part of its hedging, balancing, and optimization activities.

Any hedging, balancing, and optimization activities that we engage in are directly related to exposures that arise from our ownership and operation of power plants and gas reserves and are designed to protect or enhance our "spark spread" (the difference between our fuel cost and the revenue we receive for our electric generation). In many of these transactions CES purchases and resells power and gas in contracts with third parties (typically trading companies). We also engage in limited trading activity as described below.

We utilize derivatives, which are defined in Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities" to include many physical commodity contracts and commodity financial instruments such as exchange-traded swaps and forward contracts, to optimize the returns that we are able to achieve from our power and gas assets. While certain of our contracts are considered energy trading contracts as defined in Emerging Issues Task Force ("EITF") Issue No. 98-10, our traders have very low capital at risk and value at risk limits for energy trading, and our risk management policy limits, at any given time, our net sales of power and our net purchases of gas to our generating capacity and fuel consumption requirements, respectively, calculated on a total portfolio basis. Total electricity and gas trading gains recognized in 2001, consisting of unrealized mark-to-market gains as well as realized gains, together accounted for approximately 12% of our gross profit. This model is markedly different from that of companies that actively and extensively engage in commodity trading operations that are unrelated to underlying physical assets. Following is a discussion of the types of electricity and gas hedging, balancing, optimization, and trading activities in which CES engages. The accounting treatment for these various types of activities is discussed in Note 19 to our consolidated financial statements and in management's discussion and analysis of financial condition and results of operation.

Electricity Transactions

- *Electricity hedging* activities are done to reduce potential volatility in future results. An example of an electricity hedging transaction would be one in which we sell power at a fixed rate to allow us to predict the future revenues from our portfolio of generating plants. Hedging is a dynamic process; from time to time we adjust the extent to which our portfolio is hedged. An example of an electricity hedge adjusting transaction would be the purchase of power in the market to reduce the extent to which we had previously hedged our generation portfolio through fixed price power sales. To illustrate, suppose we had elected to hedge 65% of our portfolio of generation capacity for the following six months but then believed that prices for electricity were going to steadily move up during that same period. We might buy electricity on the open market to reduce our hedged position to, say, 50%. If electricity prices, do in fact increase, we might then sell electricity again to increase our hedged position back to the 65% level.

- *Electricity balancing* activities are typically short-term in nature and are done to make sure that sales commitments to deliver power are fulfilled. An example of an electricity balancing transaction would be where one of our generating plants has an unscheduled outage so we buy replacement power to deliver to a customer to meet our sales commitment.

- *Electricity optimization* activity, also generally short-term in nature, is done to maximize our profit potential by executing the most profitable alternatives in the power markets. An example of an electricity optimization transaction would be fulfilling a power sales contract with power purchases from third parties instead of generating power when the market price for power is below the cost of generation. In all cases, optimization activity is associated with the operating flexibility in our systems of power plants, natural gas assets, and gas and power contracts. That flexibility provides us with alternatives to most profitably manage our portfolio.

- *Energy trading* activities are done with the purpose of profiting from movement in commodity prices or to transact business with customers in market areas where we do not have generating assets. An example of an electricity trading contract would be where we buy and sell electricity, typically with trading company counterparties, solely to profit from electricity price movements. We have engaged in limited activity of this type to date in terms of earnings impact. Mostly, it is done by CES through short-term contracts. Another example of an electricity trading contract would be one in which we transact with customers in market areas where we do not have generating assets, generally to develop market experience and customer relations in areas where we expect to have generation assets in the future. We have done a small number of such transactions to date.

Natural Gas Transactions

- *Gas hedging* activities are also done to reduce potential volatility in future results. An example of a gas hedging transaction would be where we purchase gas at a fixed rate to allow us to predict the future costs of fuel for our generating plants or conversely where we enter into a financial forward contract to essentially swap floating rate (indexed) gas for fixed price gas. Similar to electricity hedging, gas hedging is a dynamic process, and from time to time we adjust the extent to which our portfolio is hedged. To illustrate, suppose we had elected to hedge 65% of our gas requirements for our generation capacity for the next six months through fixed price gas purchases but then believed that prices for gas were going to steadily decline during that same period. We might sell fixed price gas on the open market to reduce our hedged gas position to 50%. If gas prices do in fact decrease, we might then buy fixed price gas again to increase our hedged position back to the 65% level.
- *Gas balancing* activities are typically short-term in nature and are done to make sure that purchase commitments for gas are adjusted for changes in production schedules. An example of a gas balancing transaction would be where one of our generating plants has an unscheduled outage so we sell the gas that we had purchased for that plant to a third party.
- *Gas optimization* activities are also generally short-term in nature and are done to maximize our profit potential by executing the most profitable alternatives in the gas markets. An example of gas optimization is selling our gas supply, not generating power, and fulfilling power sales contracts with power purchases from third parties, instead of generating power when market gas prices spike relative to our gas supply cost.
- *Gas trading* activities are done with the purpose of profiting from movement in commodity prices. An example of gas trading contracts would be where we buy and sell gas, typically with a trading company counterparty, solely to profit from gas price movements or where we transact with customers in market areas where we do not have fuel consumption requirements. We have engaged in a limited level of this type of activity to date. Mostly it is done by CES and through short-term contracts.

In some instances economic hedges may not be designated as hedges for accounting purposes. The accounting treatment of our various risk management and trading activities is governed by SFAS No. 133 and EITF Issue No. 98-10, as discussed above. An example of an economic hedge that is not a hedge for accounting purposes would be a long-term fixed price electric sales contract that economically hedges us against the risk of falling electric prices, but which for accounting purposes is exempted from derivative accounting under SFAS No. 133 as a normal sale.

GOVERNMENT REGULATION

We are subject to complex and stringent energy, environmental and other governmental laws and regulations at the federal, state and local levels in connection with the development, ownership and operation of our energy generation facilities. Federal laws and regulations govern transactions by electric and gas utility companies, the types of fuel which may be utilized by an electricity generating plant, the type of energy which may be produced by such a plant and the ownership of a plant. State utility regulatory commissions must approve the rates and, in some instances, other terms and conditions under which public utilities sell at retail electricity that they have purchased from independent producers. Under certain circumstances where specific exemptions are otherwise unavailable, state utility regulatory commissions may have broad jurisdiction over non-utility electric power plants. Energy producing projects also are subject to federal, state and local laws and administrative regulations which govern the emissions and other substances produced, discharged or disposed of by a plant and the geographical location, zoning, land use and operation of a plant. Applicable federal environmental laws typically have both state and local enforcement and implementation provisions. These environmental laws and regulations generally require that a wide variety of permits and other approvals be obtained before the commencement of construction or operation of an energy producing facility and that the facility then operate in compliance with such permits and approvals.

Federal Energy Regulation

PURPA

The enactment of PURPA and the adoption of regulations thereunder by FERC provided incentives for the development of cogeneration facilities and small power production facilities (those utilizing renewable fuels and having a capacity of less than 80 megawatts).

A domestic electricity generating project must be a QF under FERC regulations in order to take advantage of certain rate and regulatory incentives provided by PURPA. PURPA exempts owners of QFs from the Public Utility Holding Company Act of 1935, as amended (PUHCA), and exempts QFs from most provisions of the Federal Power Act (the FPA) and, except under certain limited circumstances, state laws concerning rate or financial regulation. These exemptions are important to us and our competitors. We believe that each of the electricity-generating projects in which we own an interest and which operates as a QF power producer currently meets the requirements under PURPA necessary for QF status.

PURPA provides two primary benefits to QFs. First, QFs generally are relieved of compliance with extensive federal and state regulations that control the financial structure of an electricity generating plant and the prices and terms on which electricity may be sold by the plant. Second, FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's avoided cost, and that the utility sell back-up power to the QF on a non-discriminatory basis. The term avoided cost is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates lower than the utilities' avoided costs. While public utilities are not explicitly required by PURPA to enter into long-term power sales agreements, PURPA helped to create a regulatory environment in which it has been common for long-term agreements to be negotiated.

In order to be a QF, a cogeneration facility must produce not only electricity, but also useful thermal energy for use in an industrial or commercial process for heating or cooling applications in certain proportions to the facilities total energy output, and must meet certain energy efficiency standards. A geothermal facility may qualify as a QF if it produces less than 80 megawatts of electricity. Finally, a QF (including a geothermal QF or other qualifying small power producer) must not be controlled or more than 50% owned by one or more electric utilities or by most electric utility holding companies, or one or more subsidiaries of such a utility or holding company or any combination thereof.

We endeavor to develop our projects, monitor compliance by the projects with applicable regulations and choose our customers in a manner which minimizes the risks of any project losing its QF status. Certain factors necessary to maintain QF status are, however, subject to the risk of events outside our control. For example, loss of a thermal energy customer or failure of a thermal energy customer to take required amounts of thermal energy from a cogeneration facility that is a QF could cause the facility to fail requirements regarding the level of useful thermal energy output. Upon the occurrence of such an event, we would seek to replace the thermal energy customer or find another use for the thermal energy which meets PURPA's requirements, but no assurance can be given that this would be possible.

If one of the facilities in which we have an interest should lose its status as a QF, the project would no longer be entitled to the exemptions from PUHCA and the FPA. This could also trigger certain rights of termination under the facility's power sales agreement, could subject the facility to rate regulation as a public utility under the FPA and state law and could result in us inadvertently becoming an electric utility holding company by owning more than 10% of the voting securities of, or controlling, a facility that would no longer be exempt from PUHCA. This could cause all of our remaining projects to lose their qualifying status, because QFs may not be controlled or more than 50% owned by such electric utility holding companies. Loss of QF status may also trigger defaults under covenants to maintain QF status in the projects power sales agreements, steam sales agreements and financing agreements and result in termination, penalties or acceleration of indebtedness under such agreements such that loss of status may be on a retroactive or a prospective basis.

Under the Energy Policy Act of 1992, if a facility can be qualified as an exempt wholesale generator (EWG), meaning that all of its output is sold for resale rather than to end users, it will be exempt from PUHCA even if it does not qualify as a QF. Therefore, another response to the loss or potential loss of QF status would be to apply to have the project qualified as an EWG. However, assuming this changed status would be permissible under the terms of the applicable power sales agreement, rate approval from FERC would be required. In addition, the facility would be required to cease selling electricity to any retail customers (such as the thermal energy customer) to retain its EWG status and could become subject to state regulation of sales of thermal energy. See Public Utility Holding Company Regulation.

Currently, Congress is considering proposed legislation that would repeal PUHCA and amend PURPA by limiting its mandatory purchase obligation to existing contracts. In light of the circumstances in California, the Pacific Gas and Electric Company bankruptcy and the Enron bankruptcy, among other events in 2001, there are a number of federal legislative and regulatory initiatives that could result in changes in how the energy markets are regulated. We do not know whether this legislation or regulatory initiatives will be adopted or, if adopted, what form they may take. We cannot provide assurance that any legislation or regulation ultimately adopted would not adversely affect our existing domestic projects.

Public Utility Holding Company Regulation

Under PUHCA, any corporation, partnership or other legal entity which owns or controls 10% or more of the outstanding voting securities of a public utility company, or a company which is a holding company for a public utility company, is subject to registration with the Securities and Exchange Commission (SEC) and regulation under PUHCA, unless eligible for an exemption. A holding company of a public utility company that is subject to registration is required by PUHCA to limit its utility operations to a single integrated utility system and to divest any other operations not functionally related to the operation of that utility system. Approval by the SEC is required for nearly all important financial and business dealings of a registered holding company. Under PURPA, most QFs are not public utility companies under PUHCA.

The Energy Policy Act of 1992, among other things, amends PUHCA to allow EWGs, under certain circumstances, to own and operate non-QF electric generating facilities without subjecting those producers to registration or regulation under PUHCA. The effect of such amendments has been to enhance the development of non-QFs which do not have to meet the fuel, production and ownership requirements of PURPA. We believe that these amendments benefit us by expanding our ability to own and operate facilities that do not qualify for QF status. However, they have also resulted in increased competition by allowing utilities and their affiliates to develop such facilities which are not subject to the constraints of PUHCA.

Federal Natural Gas Transportation Regulation

We have an ownership interest in 38 gas-fired cogeneration plants in operation or under construction. The cost of natural gas is ordinarily the largest expense of a gas-fired project and is critical to the projects economics. The risks associated with using natural gas can include the need to arrange transportation of the gas from great distances, including obtaining removal, export and import authority if the gas is transported from Canada; the possibility of interruption of the gas supply or transportation (depending on the quality of the gas reserves purchased or dedicated to the project, the financial and operating strength of the gas supplier, whether firm or non-firm transportation is purchased and the operations of the gas pipeline); and obligations to take a minimum quantity of gas and pay for it (i.e., take-and-pay obligations).

Pursuant to the Natural Gas Act, FERC has jurisdiction over the transportation and storage of natural gas in interstate commerce. With respect to most transactions that do not involve the construction of pipeline facilities, regulatory authorization can be obtained on a self-implementing basis. However, interstate pipeline rates and terms and conditions for such services are subject to continuing FERC oversight.

Federal Power Act Regulation

Under the FPA, FERC is authorized to regulate the transmission of electric energy and the sale of electric energy at wholesale in interstate commerce. Unless otherwise exempt, any person that owns or operates facilities used for such purposes is considered a public utility subject to FERC jurisdiction. FERC regulation under the FPA includes approval of the disposition of utility property, authorization of the issuance of securities by public utilities, regulation of the rates, terms and conditions for the transmission or sale of electric energy at wholesale in interstate commerce, the regulation of interlocking directorates, a uniform system of accounts and reporting requirements for public utilities.

FERC regulations implementing PURPA provide that a QF is exempt from regulation under the foregoing provisions of the FPA. An EWG is not exempt from the FPA and therefore an EWG that makes sales of electric energy at wholesale in interstate commerce is subject to FERC regulation as a public utility. However, many of the regulations which customarily apply to traditional public utilities have been waived or relaxed for power marketers, EWGs and other non-traditional public utilities that lack market power. EWGs are regularly granted authorization to charge market-based rates, blanket authority to issue securities, and waivers of certain FERC requirements pertaining to accounts, reports and interlocking directorates. Such action is intended to implement FERC's policy to foster a more competitive wholesale power market.

Many of the generating projects in which we own an interest are operated as QFs and are therefore exempt from FERC regulation under the FPA. However, several of our generating projects are or will be EWGs subject to FERC jurisdiction under the FPA. Several of our affiliates have been granted authority to engage in sales at market-based rates and to issue securities, and have also been granted the customary waivers of FERC regulations available to non-traditional public utilities; however, we cannot assure that such authorities or waivers will be granted in the future to other affiliates.

State Regulation

State public utility commissions (PUCs) have historically had broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in their states and to promulgate regulation for implementation of PURPA. Since a power sales agreement becomes a part of a utility's cost structure (generally reflected in its retail rates), power sales agreements with independent electricity producers, such as EWGs, are potentially under the regulatory purview of PUCs and in particular the process by which the utility has entered into the power sales agreements. If a PUC has approved the process by which a utility secures its power supply, a PUC is generally inclined to pass through the expense associated with a power purchase agreement with an independent power producer to the utility's retail customers. However, a regulatory commission under certain circumstances may disallow the full reimbursement to a utility for the cost to purchase power from a QF or an EWG. In addition, retail sales of electricity or thermal energy by an independent power producer may be subject to PUC regulation depending on state law. Independent power producers which are not QFs under PURPA, or EWGs pursuant to the Energy Policy Act of 1992, are considered to be public utilities in many states and are subject to broad regulation by a PUC, ranging from requirement of certificate of public convenience and necessity to regulation of organizational, accounting, financial and other corporate matters. States may assert jurisdiction over the siting and construction of electricity generating facilities including QFs and EWGs and, with the exception of QFs, over the issuance of securities and the sale or other transfer of assets by these facilities.

State PUCs also have jurisdiction over the transportation of natural gas by local distribution companies (LDCs). Each states regulatory laws are somewhat different; however, all generally require the LDC to obtain approval from the PUC for the construction of facilities and transportation services if the LDCs generally applicable tariffs do not cover the proposed transaction. LDC rates are usually subject to continuing PUC oversight.

Regulation of Canadian Gas

The Canadian natural gas industry is subject to extensive regulation by governmental authorities. At the federal level, a party exporting gas from Canada must obtain an export license from the Canadian National

Energy Board (NEB). The NEB also regulates Canadian pipeline transportation rates and the construction of pipeline facilities. Gas producers also must obtain a removal permit or license from provincial authorities before natural gas may be removed from the province, and provincial authorities may regulate intra-provincial pipeline and gathering systems. In addition, a party importing natural gas into the United States first must obtain an import authorization from the U.S. Department of Energy.

Environmental Regulations

The exploration for and development of geothermal resources, oil, gas liquids and natural gas, and the construction and operation of wells, fields, pipelines, various other mid stream facilities and equipment, and power projects, are subject to extensive federal, state and local laws and regulations adopted for the protection of the environment and to regulate land use. The laws and regulations applicable to us primarily involve the discharge of emissions into the water and air and the use of water, but can also include wetlands preservation, endangered species, hazardous materials handling and disposal, waste disposal and noise regulations. These laws and regulations in many cases require a lengthy and complex process of obtaining licenses, permits and approvals from federal, state and local agencies.

Noncompliance with environmental laws and regulations can result in the imposition of civil or criminal fines or penalties. In some instances, environmental laws also may impose clean-up or other remedial obligations in the event of a release of pollutants or contaminants into the environment. The following federal laws are among the more significant environmental laws as they apply to us. In most cases, analogous state laws also exist that may impose similar, and in some cases more stringent, requirements on us as those discussed below.

Clean Air Act

The Federal Clean Air Act of 1970 (the Clean Air Act) provides for the regulation, largely through state implementation of federal requirements, of emissions of air pollutants from certain facilities and operations. As originally enacted, the Clean Air Act sets guidelines for emissions standards for major pollutants (i.e., sulfur dioxide and nitrogen oxide) from newly built sources. In late 1990, Congress passed the Clean Air Act Amendments (the 1990 Amendments). The 1990 Amendments attempt to reduce emissions from existing sources, particularly previously exempted older power plants. We believe that all of our operating plants are in compliance with federal performance standards mandated for such plants under the Clean Air Act and the 1990 Amendments.

Clean Water Act

The Federal Clean Water Act (the Clean Water Act) establishes rules regulating the discharge of pollutants into waters of the United States. We are required to obtain a wastewater and storm water discharge permit for wastewater and runoff, respectively, from certain of our facilities. We believe that, with respect to our geothermal operations, we are exempt from newly promulgated federal storm water requirements. We believe that we are in material compliance with applicable discharge requirements of the Clean Water Act.

Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act (RCRA) regulates the generation, treatment, storage, handling, transportation and disposal of solid and hazardous waste. We believe that we are exempt from solid waste requirements under RCRA. However, particularly with respect to our solid waste disposal practices at the power generation facilities and steam fields located at The Geysers, we are subject to certain solid waste requirements under applicable California laws. We believe that our operations are in material compliance with such laws.

Comprehensive Environmental Response, Compensation, and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA or Superfund), requires cleanup of sites from which there has been a release or threatened release of hazardous substances and authorizes the United States Environmental Protection Agency to take any necessary response action at Superfund sites, including ordering potentially responsible parties (PRPs) liable for the release to take or pay for such actions. PRPs are broadly defined under CERCLA to include past and present owners and operators of, as well as generators of wastes sent to, a site. As of the present time, we are not subject to liability for any Superfund matters. However, we generate certain wastes, including hazardous wastes, and send certain of our wastes to third party waste disposal sites. As a result, there can be no assurance that we will not incur liability under CERCLA in the future.

Various Federal and State Laws Regulating Oil and Gas Exploration and Production Activities, Including the Operation of Midstream Assets

Regulations and procedures as issued by U.S. Dept. of Interior/Bureau of Land Management for our federal oil and gas leases, U.S. Dept. of Interior/Bureau of Indian Affairs for our oil and gas leases on Indian lands and State agencies for our State oil and gas leases; regulations and procedures as issued by the State agencies in California, Colorado, Wyoming, Montana, New Mexico, Texas, Oklahoma, Arkansas, Mississippi and Louisiana, including operating permits and bonds covering our onshore operations; and regulations by the U.S. Department of Transportation/U.S. Coast Guard and Office of Pipeline Safety, the U.S. Department of Interior/ Minerals Management Service covering our offshore U.S. Gulf of Mexico operations including operating permits and bonds. These agencies have varied remedies for enforcement, including fines and penalties, permit and license revocation, and suspension of production. As a result, there can be no assurance that we will not incur liability for fines and penalties or otherwise subject Calpine to the various remedies by these agencies, but we believe that we are currently in material compliance.

RISK FACTORS

See "Risk Factors" section starting on page F-5 under "Management's Discussion and Analysis of Financial Condition and Results of Operation" included elsewhere in this report.

EMPLOYEES

As of December 31, 2001, we employed 3,719 people, of whom 50 were represented by collective bargaining agreements. We have never experienced a work stoppage or strike, and we consider relations with our employees to be good. Although we are an asset-based company, we are successful because of the talents, intelligence, resourcefulness and energy level of our employees. As discussed in our strategy section, our employee knowledge base enables us to optimize the value and profitability of our electricity production and prudently manage the risks inherent in our business.

Item 2. *Properties*

Our principal executive office located in San Jose, California is held under leases that expire through 2008, and we also lease offices in Dublin, California; Houston, Texas; Boston, Massachusetts; Northbrook, Illinois and Calgary, Alberta. We hold additional leases for our Construction Management office in Folsom, California and for other satellite offices.

We either lease or own the land upon which our power-generating facilities are built. We believe that our properties are adequate for our current operations.

We have leasehold interests in 105 leases comprising 21,217 acres of federal, state and private geothermal resource lands in The Geysers area in northern California. In the Glass Mountain and Medicine Lake areas in northern California, we hold leasehold interests in 42 leases comprising approximately 47,159 acres of federal geothermal resource lands.

In general, under these leases, we have the exclusive right to drill for, produce and sell geothermal resources from these properties and the right to use the surface for all related purposes. Each lease requires the payment of annual rent until commercial quantities of geothermal resources are established. After such time, the leases require the payment of minimum advance royalties or other payments until production commences, at which time production royalties are payable. Such royalties and other payments are payable to landowners, state and federal agencies and others, and vary widely as to the particular lease. The leases are generally for initial terms varying from 10 to 20 years or for so long as geothermal resources are produced and sold. Certain of the leases contain drilling or other exploratory work requirements. In certain cases, if a requirement is not fulfilled, the lease may be terminated and in other cases additional payments may be required. We believe that our leases are valid and that we have complied with all the requirements and conditions material to the continued effectiveness of the leases. A number of our leases for undeveloped properties may expire in any given year. Before leases expire, we perform geological evaluations in an effort to determine the resource potential of the underlying properties. We cannot assure that we will decide to renew any expiring leases.

Based on independent petroleum engineering reports of Netherland, Sewell & Associates, Inc., and Gilbert Laustsen Jung Associates, Ltd., as of December 31, 2001, utilizing year end product prices and costs held constant, our proved oil, natural gas, and natural gas liquids ("NGLs") reserve volumes, in millions of barrels ("MMBbls") and billions of cubic feet ("Bcf") are as follows:

	As of December 31, 2001	
	Oil and NGLs (MMBbls)	Gas (Bcf)
United States		
Proved developed	2.7	378
Proved undeveloped	1.9	212
Total	4.6	590
Canada		
Proved developed	34.1	394
Proved undeveloped	4.5	51
Total	38.6	445
Consolidated		
Proved developed	36.8	772
Proved undeveloped	6.4	263
Total	43.2(1)	1,035

(1) 43.2 MMBbls of oil is equivalent to 259 Bcf of gas.

Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimated future development costs associated with proved non-producing and proved undeveloped reserves as of December 31, 2001, totaled approximately $222.3 million.

The following table sets forth our interest in undeveloped acreage, developed acreage and productive wells in which we own a working interest as of December 31, 2001. Gross represents the total number of acres or wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in the gross acres or wells. Productive wells are wells in which we have a working interest and are capable of producing oil or natural gas.

	Undeveloped Acres		Developed Acres		Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
United States						
Arkansas	—	—	8,823	3,967	33	8
California	19,236	14,738	78,588	73,901	221	169
Colorado	22,843	18,519	28,721	16,803	63	62
Louisiana	46,472	46,228	37,073	36,821	33	4
Mississippi	270	237	10,125	4,584	15	1
Montana	9,583	7,423	—	—	2	—
New Mexico	640	640	6,011	5,545	13	11
Oklahoma	4,765	953	29,716	13,927	86	10
Texas	81,556	61,832	45,874	37,867	550	209
Wyoming	46,016	33,664	—	—	—	—
Offshore	6,250	6,250	14,510	11,892	28	15
Total United States	237,631	190,484	259,441	205,307	1,044	489
Canada	1,672,199	1,197,269	946,809	507,234	2,836	984
Consolidated Total	1,909,830	1,387,753	1,206,250	712,541	3,880	1,473

Gross Wells Drilled

The following table sets forth the number of gross exploratory and gross development wells drilled in which the Company participated during the last three fiscal years. The number of wells drilled refers to the number of wells commenced at any time during the respective fiscal year. Productive wells are either producing wells or wells capable of commercial production. At December 31, 2001, the Company was in the process of drilling three wells (net 1.8) in the US and six wells (net 4.8) in Canada.

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
2001						
United States	5	2	7	66	12	78
Canada	2	—	2	186	26	212
Total	7	2	9	252	38	290
2000						
United States	7	4	11	28	3	31
Canada	7	2	9	154	46	200
Total	14	6	20	182	49	231
1999						
United States	—	—	—	3	—	3
Canada	32	17	49	73	19	92
Total	32	17	49	76	19	95

Net Wells Drilled

The following table sets forth, for each of the last three fiscal years, the number of net exploratory and net developmental wells drilled by the Company:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
2001						
United States	2.2	1.0	3.2	58.9	7.4	66.3
Canada	1.6	—	1.6	97.2	19.7	116.9
Total	3.8	1.0	4.8	156.1	27.1	183.2
2000						
United States	3.2	1.0	4.2	15.5	1.4	16.9
Canada	2.8	1.3	4.1	93.3	36.0	129.3
Total	6.0	2.3	8.3	108.8	37.4	146.2
1999						
United States	0.0	0.0	0.0	0.3	0.0	0.3
Canada	25.8	13.9	39.7	43.2	15.2	58.4
Total	25.8	13.9	39.7	43.5	15.2	58.7

The following table shows the Company's annual average wellhead sales prices and average production costs (excluding production taxes). The average sales prices include realized gains and losses for derivative contracts the Company enters to manage price risk related to the Company's sales volumes.

	2001	2000	1999
UNITED STATES			
Sales price			
Natural gas (per Mcf)	$ 4.91	$ 3.96	$ 2.66
Oil and condensate (per barrel)	$23.30	$24.71	$22.25
Natural gas liquids (per barrel)	$15.67	$15.77	$14.05
Production cost (per Mcfe)	$ 0.53	$ 0.48	$ 0.45
CANADA			
Sales price			
Natural gas (per Mcf)	$ 3.25	$ 3.18	$ 1.60
Oil and condensate (per barrel)	$20.16	$27.03	$16.99
Natural gas liquids (per barrel)	$20.96	$24.67	$13.38
Production cost (per Mcfe)	$ 0.53	$ 0.43	$ 0.42
TOTAL			
Sales price			
Natural gas (per Mcf)	$ 3.81	$ 3.40	$ 1.66
Oil and condensate (per barrel)	$20.38	$26.92	$17.04
Natural gas liquids (per barrel)	$20.90	$24.56	$13.39
Production cost (per Mcfe)	$ 0.53	$ 0.44	$ 0.42

Item 3. *Legal Proceedings*

Calpine Corporation v. Automated Credit Exchange ("ACE"). On March 5, 2002, Calpine sued ACE in the Superior Court of the State of California for the County of Alameda for negligence and breach of contract to recover reclaim trading credits, a form of emission reduction credits that should have been held in Calpine's account with U.S. Trust Company (US Trust). ACE is a broker in emission reduction credits based in Pasadena, California. Calpine had paid ACE for Nitrogen oxide (NOx) coastal credits that were to be purchased by ACE and held by US Trust. The credits were to be held by US Trust pursuant to a Credit Holding Agreement, which provided, among other things, that US Trust was to hold the credits until receiving instructions from ACE to disburse the credits. ACE had agreed that (i) upon prior written instruction from Calpine, to instruct US Trust to take such actions as may be directed by Calpine to disburse the credits held in escrow pursuant to the Credit Holding Agreement and (ii) not to take any action, or otherwise instruct US Trust to take any action, concerning the credits held in escrow pursuant to the Credit Holding Agreement without prior written instruction from Calpine.

Ben Johnson v. Peter Cartwright, et al. On December 17, 2001, a shareholder filed a derivative lawsuit on behalf of Calpine against its directors and one of its senior officers. This lawsuit is styled *Johnson vs. Cartwright, et al.* (No. CV803872), and is pending in the California Superior Court, Santa Clara County. Calpine is a nominal defendant in this lawsuit, which alleges claims relating to purportedly misleading statements about Calpine and stock sales by certain of the director defendants and the officer defendant. Calpine has filed a demurrer asking the court to dismiss the complaint on the ground that the shareholder plaintiff lacks standing to pursue claims on behalf of Calpine. The individual defendants have filed a demurrer asking the court to dismiss the complaint on the ground that it fails to state any claims against them.

Securities Class Action Lawsuits. Over the past several weeks, five shareholder lawsuits have been filed against Calpine and certain of its officers in the United States District Court, Northern District of California. The action captioned *Weisz vs. Calpine Corp., et al.*, filed March 11, 2002, is a purported class action on behalf of purchasers of Calpine stock between March 15, 2001 and December 13, 2001. The four other actions, captioned *Local 144 Nursing Home Pension Fund vs. Calpine Corp., Lukowski vs. Calpine Corp., Hart vs. Calpine Corp.,* and *Atchison vs. Calpine Corp.*, were filed between March 18, 2002 and March 26, 2002. The complaints in these four actions are virtually identical, and each was filed by the same law firm, in conjunction with other law firms as co-counsel. All four lawsuits are purported class actions on behalf of purchasers of Calpine's securities between January 5, 2001 and December 13, 2001.

The complaints in these five actions allege that, during the purported class periods, defendants Calpine and certain senior executives issued false and misleading statements about Calpine's financial condition in violation of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, as well as Rule 10b-5. These actions seek an unspecified amount of damages, in addition to other forms of relief. We expect that these actions, as well as any related actions that may be filed in the future, will be consolidated by the court into a single securities class action. We consider the lawsuits to be without merit, and we intend to defend vigorously against these allegations.

Public Utilities Commission of the State of California v. Sellers of Long Term Contracts to the California Department of Water Resources; California Electricity Oversight Board v. Sellers of Long Term Contracts to the California Department of Water Resources. In February 2002, both the California Public Utilities Commission and the California Electric Oversight Board filed complaints under Section 206 of the Federal Power Act with the Federal Energy Regulatory Commission (FERC) (EL02-60-000 and EL02-62-000, respectively) alleging that the prices and terms of the long-term contracts with the California Department of Water Resources (DWR) are unjust and unreasonable and counter to the public interest. Calpine Energy Services, L.P. (CES) is a respondent and the four long-term contracts entered into between CES and DWR are subject to the complaint. *(see, Risk Factors — California Long-Term Supply Agreements)* The FERC has noticed this proceeding and responsive pleadings were due from the respondents on or before March 22, 2002. Calpine believes that the complaints are without merit and intends to defend its position vigorously.

Lockport Energy Associates, L.P. and the New York Public Service Commission v. New York State Electricity and Gas Company. An action was filed against Lockport Energy Associates, L.P. and the

New York Public Service Commission ("NYPSC") in August 1997 by New York State Electricity and Gas Company ("NYSEG") in the Federal District Court for the Northern District of New York. NYSEG requested the Court to direct NYPSC and FERC to modify contract rates to be paid to the Lockport Power Plant. In October 1997 NYPSC filed a cross-claim alleging that the FERC violated the Public Utility Regulatory Policies Act of 1978, as amended, and the Federal Power Act by failing to reform the NYSEG contract that was previously approved by the NYPSC. On September 29, 2000, the New York Federal District Court dismissed NYSEG's complaint and NYPSC's cross-claim. The Court stated that FERC has no authority to alter or waive its regulations or exemptions to alter the terms of the applicable power purchase agreements and that Qualifying Facilities are entitled to the benefit of their bargain, even if at the expense of NYSEG and its ratepayers. On October 5, 2001, the United States Court of Appeals affirmed the judgment of the federal district court and dismissed all of the claims raised by NYSEG against Lockport.

The Company is involved in various other claims and legal actions arising out of the normal course of business. The Company does not expect that the outcome of these proceedings will have a material adverse effect on the Company's financial position or results of operations.

Item 4. *Submission of Matters to a Vote of Security Holders*

None.

PART II

Item 5. *Market for Registrant's Common Equity and Related Stockholder Matters*

Calpine's common stock is traded on the New York Stock Exchange under the symbol "CPN." Public trading of the common stock commenced on September 20, 1996. Prior to that, there was no public market for the common stock. The following table sets forth, for the periods indicated, the high and low sale price per share of the common stock on The New York Stock Exchange. The information in the following table reflects the 2 for 1 stock split that became effective on June 8, 2000, and the 2 for 1 stock split that became effective on November 14, 2000.

	High	Low
2000		
First Quarter	$30.75	$16.09
Second Quarter	35.22	18.13
Third Quarter	52.25	32.25
Fourth Quarter	52.97	32.25
2001		
First Quarter	$58.04	$29.00
Second Quarter	57.35	36.20
Third Quarter	46.00	18.90
Fourth Quarter	28.85	10.00

As of March 26, 2002, there were approximately 1,347 holders of record of our common stock. On March 26, 2002, the last sale price reported on the New York Stock Exchange for our common stock was $12.18 per share.

We have not declared any cash dividends on the common stock during the past two fiscal years. We do not anticipate paying any cash dividends on the common stock in the foreseeable future because we intend to retain our earnings to finance the expansion of our business and for general corporate purposes. In addition, our ability to pay cash dividends is restricted under certain of our indentures and our other debt agreements.

Future cash dividends, if any, will be at the discretion of our board of directors and will depend upon, among other things, our future operations and earnings, capital requirements, general financial condition, contractual restrictions and such other factors as the board of directors may deem relevant.

Retirement Savings Plan. Effective September 1999 Calpine Corporation amended its Retirement Savings Plan to add a Calpine Common Stock Fund as one of the investment options for employee contributions to the Plan. As the result of this amendment, the exemption from registration under the Securities Act of 1933 for both the plan participation interests and the shares of Common Stock previously afforded by Section 3(a)(2) of the Securities Act ceased to be available. In April 2000 Calpine filed with the Securities and Exchange Commission a registration statement on Form S-8 registering both the plan participation interests and the shares of Common Stock offered and sold under the Plan after the effective date of the registration statement. While Calpine believes that many of the sales made prior to such registration would qualify as exempt transactions under Section 4(2) of the Securities Act, it has not undertaken an evaluation of the eligibility of each Plan participant to purchase securities in a private placement, and expects that such an evaluation would show that not all of the Plan participants who purchased unregistered securities would qualify.

Calpine estimates that, from the date of the plan amendment through the effective date of the registration statement, (i) the market value of unregistered plan participation interests sold was $25.9 million and (ii) the number of unregistered shares of Common Stock sold was 1,542,860. Because employee contributions that are directed to the Calpine Common Stock Fund are used by the Plan's trustee to purchase shares of Common Stock in the open market, Calpine does not receive any proceeds from the sale of the shares.

4% Convertible Senior Notes due 2006. On December 26, 2001, we completed a private placement of $1.0 billion aggregate principal amount of 4% Convertible Senior Notes due 2006 (the "senior notes due 2006"). The initial purchaser of the senior notes due 2006 was Deutsche Bank Alex. Brown Inc. (the "initial purchaser"). The initial purchaser exercised its option to acquire an additional $200.0 million aggregate principal amount of the senior notes due 2006 by purchasing an additional $100.0 million aggregate principal amount of the senior notes due 2006 on each of December 31, 2001 and January 3, 2002. The offering price of the senior notes due 2006 was 100% of the principal amount of the senior notes due 2006, less an aggregate underwriting discount of $30.0 million. Each sale of the senior notes due 2006 to the initial purchaser was exempt from registration in reliance on Section 4(2) and Regulation D under the Securities Act of 1933, as amended, as a transaction not involving a public offering. The senior notes due 2006 were re-offered by the initial purchaser to qualified institutional buyers in reliance on Rule 144A under the Securities Act.

The senior notes due 2006 are convertible into shares of our common stock at a conversion price of $18.07 per share. The conversion price is subject to adjustment in certain circumstances. We have reserved 66,408,411 shares of our authorized common stock for issuance upon conversion of the senior notes due 2006. The senior notes due 2006 are convertible at any time on or before the close of business on the day that is two business days prior to the maturity date, December 26, 2006, unless we have previously repurchased the senior notes due 2006. Holders of the senior notes due 2006 have the right to require us to repurchase their senior notes due 2006 on December 26, 2004. We may choose to pay the repurchase prince in cash or shares of common stock, or a combination thereof.

Zero Coupon Convertible Debentures due 2021. On April 30, 2001, we completed a private placement of $850.0 million aggregate principal amount of Zero Coupon Convertible Debentures due 2021 (the "debentures due 2021"). The initial purchaser of the debentures due 2021 was Goldman, Sachs & Co. (the "initial purchaser"). On April 30, 2001, the initial purchaser exercised its option to acquire an additional $150.0 million aggregate principal amount of the debentures due 2021. The offering price of the debentures due 2021 was 100% of the principal amount of the debentures due 2021, less an aggregate underwriting discount of $22.5 million. Each sale of the debentures due 2021 to the initial purchaser was exempt from registration in reliance on Section 4(2) and Regulation D under the Securities Act of 1933, as amended, as a transaction not involving a public offering. The debentures due 2021 were re-offered by the initial purchaser to qualified institutional buyers in reliance on Rule 144A under the Securities Act.

The debentures due 2021 are convertible into shares of our common stock at a conversion ratio of 13.2714 shares of common stock per each $1,000 principal amount of debentures due 2021, which is equivalent to a conversion price of $75.35 per share. The conversion ratio is subject to adjustment in certain circumstances. We have reserved 13,271,400 shares of our authorized common stock for issuance upon conversion of the debentures due 2021. The debentures due 2021 are convertible at any time on or before the close of business on April 29, 2021, the day prior to the maturity date, April 30, 2021, unless we have previously redeemed or repurchased the debentures due 2021. Holders of debentures due 2021 called for redemption will be entitled to convert them on or before the close of business on the business day immediately preceding the date fixed for redemption. Holders of the senior notes due 2006 have the right to require us to repurchase their senior notes due 2006 on April 30, 2002, 2004, 2006, 2008, 2011 and 2016. We may choose to pay the repurchase price in cash or shares of common stock, or a combination thereof (except on April 30, 2016, when the repurchase price must be paid in cash). As of March 28, 2002, $314.5 million aggregate principal amount of the debentures due 2021 had been repurchased in open market and privately negotiated transactions and $685.5 million aggregate principal amount of the debentures due 2021 remained outstanding.

Item 6. *Selected Financial Data*

The information required hereunder is set forth under "Selected Consolidated Financial Data" included in the Consolidated Financial Statements that are a part of this report.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operation*

The information required hereunder is set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operation" included elsewhere in this report.

Item 7a. *Quantitative and Qualitative Disclosure About Market Risk*

The information required hereunder is set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operation — Financial Market Risks" included in the Consolidated Financial Statements that are a part of this report.

Item 8. *Financial Statements and Supplementary Data*

The information required hereunder is set forth under "Report of Independent Public Accountants," "Consolidated Balance Sheets," "Consolidated Statements of Operations," "Consolidated Statements of Stockholders' Equity," "Consolidated Statements of Cash Flows," and "Notes to Consolidated Financial Statements" included in the Consolidated Financial Statements that are a part of this report. Other financial information and schedules are included in the Consolidated Financial Statements that are a part of this report.

Item 9. *Changes in and Disagreements With Accountants on Accounting and Financial Disclosure*

On March 22, 2002 Calpine determined to dismiss Arthur Andersen LLP ("Andersen") as its independent public accountants after completion of the audit for the year ended December 31, 2001, and appointed Deloitte and Touche LLP ("Deloitte and Touche") as its new independent public accountants for the fiscal year ending December 31, 2002. This determination followed Calpine's decision to seek proposals from independent accountants to audit Calpine's financial statements for the fiscal year ending December 31, 2002. The decision to dismiss Andersen and to retain Deloitte and Touche was approved by Calpine's Board of Directors upon the recommendation of its Audit Committee. The decision to change auditors is not a reflection of Andersen's capabilities or commitment. Andersen has provided quality service and demonstrated consistent professionalism during their 10 year relationship with Calpine. The appointment of Deloitte and Touche as Calpine's new independent public accountants is subject to stockholder ratification at Calpine's 2002 Annual Meeting of Stockholders.

The audit reports of Andersen on the consolidated financial statements of Calpine and subsidiaries as of and for the fiscal years ended December 31, 2001 and 2000, did not contain any adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty, audit scope, or accounting principles. During

Calpine's two most recent fiscal years ended December 31, 2001, and the subsequent interim period through the filing with the SEC of this Annual Report on Form 10-K there were no disagreements between Calpine and Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements if not resolved to Andersen's satisfaction would have caused them to make reference to the subject matter of the disagreement in connection with their reports.

None of the reportable events described under Item 304(a)(1)(v) of Regulation S-K occurred within Calpine's two most recent fiscal years and the subsequent interim period through the filing of this Annual Report on Form 10-K.

Calpine provided Andersen with a copy of the foregoing disclosures. A letter from Andersen dated March 29, 2002, stating its agreement with these statements is included as Exhibit 16.1 hereto.

During Calpine's two most recent fiscal years ended December 31, 2001, and the subsequent interim period through the filing of this Annual Report on Form 10-K, Calpine did not consult with Deloitte and Touche regarding any of the matters or events set forth in Item 304(a)(2)(i) and (ii) of Regulation S-K.

PART III

Item 10. *Directors and Executive Officers of the Registrant*

Incorporated by reference to Proxy Statement relating to the 2002 Annual Meeting of Stockholders to be filed.

Item 11. *Executive Compensation*

Incorporated by reference to Proxy Statement relating to the 2002 Annual Meeting of Stockholders to be filed.

Item 12. *Security Ownership of Certain Beneficial Owners and Management*

Incorporated by reference to Proxy Statement relating to the 2002 Annual Meeting of Stockholders to be filed.

Item 13. *Certain Relationships and Related Transactions*

Incorporated by reference to Proxy Statement relating to the 2002 Annual Meeting of Stockholders to be filed.

PART IV

Item 14. *Exhibits, Financial Statement Schedules, and Reports on Form 8-K*

(a)-1. **Financial Statements and Other Information**

The following items appear in Appendix F of this report:

Selected Consolidated Financial Data
Management's Discussion and Analysis of Financial Condition and Results of Operation
Report of Independent Public Accountants
Consolidated Balance Sheets, December 31, 2001 and 2000
Consolidated Statements of Operations for the Years Ended December 31, 2001, 2000, and 1999
Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2001, 2000, and 1999
Consolidated Statements of Cash Flows for the Years Ended December 31, 2001, 2000, and 1999
Notes to Consolidated Financial Statements for the Years Ended December 31, 2001, 2000, and 1999

(a)-2. **Financial Statement Schedules**

Schedule II — Valuation and Qualifying Accounts

(b) **Reports on Form 8-K**

The registrant filed the following reports on Form 8-K during the quarter ended December 31, 2001:

Date of Report	Date Filed	Item Reported
October 2, 2001	October 9, 2001	5, 7
October 11, 2001	October 12, 2001	5, 7
October 25, 2001	October 26, 2001	5, 7
October 16, 2001	November 13, 2001	5, 7
November 28, 2001	December 3, 2001	5, 7
December 6, 2001	December 7, 2001	5, 7
December 12, 2001	December 13, 2001	5, 7
November 14, 2001	December 20, 2001	5, 7

(c) **Exhibits**

The following exhibits are filed herewith unless otherwise indicated:

Exhibit Number	Description
3.1.1	Amended and Restated Certificate of Incorporation of Calpine Corporation.(a)
3.1.2	Certificate of Correction of Calpine Corporation.(b)
3.1.3	Certificate of Amendment of Amended and Restated Certificate of Incorporation of Calpine Corporation.(c)
3.1.4	Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(b)
3.1.5	Amendment to Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(b)
3.1.6	Amendment to Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(c)
3.1.7	Certificate of Designation of Special Voting Preferred Stock of Calpine Corporation.(d)
3.1.8	Amended and Restated By-laws of Calpine Corporation.(*)
4.1.1	Indenture dated as of May 16, 1996, between the Company and Fleet National Bank, as Trustee, including form of Notes.(f)
4.1.2	First Supplemental Indenture dated as of August 1, 2000, between the Company and State Street Bank and Trust Company (successor trustee to Fleet National Bank), as Trustee.(b)
4.2.1	Indenture dated as of July 8, 1997, between the Company and The Bank of New York, as Trustee, including form of Notes.(g)
4.2.2	Supplemental Indenture dated as of September 10, 1997, between the Company and The Bank of New York, as Trustee.(h)
4.2.3	Second Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.3.1	Indenture dated as of March 31, 1998, between the Company and The Bank of New York, as Trustee, including form of Notes.(i)
4.3.2	Supplemental Indenture dated as of July 24, 1998, between the Company and The Bank of New York, as Trustee.(i)
4.3.3	Second Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.4.1	Indenture dated as of March 29, 1999, between the Company and The Bank of New York, as Trustee, including form of Notes.(j)

Exhibit Number	Description
4.4.2	First Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.5.1	Indenture dated as of March 29, 1999, between the Company and The Bank of New York, as Trustee, including form of Notes.(j)
4.5.2	First Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.6.1	Indenture dated as of August 10, 2000, between the Company and Wilmington Trust Company, as Trustee.(k)
4.6.2	First Supplemental Indenture dated as of September 28, 2000, between the Company and Wilmington Trust Company, as Trustee.(b)
4.7	Indenture, dated as of April 30, 2001, between the Company and Wilmington Trust Company, as Trustee.(m)
4.8	Amended and Restated Indenture dated as of October 16, 2001, between Calpine Canada Energy Finance ULC and Wilmington Trust Company, as Trustee.(1)
4.9	Guarantee Agreement dated as of April 25, 2001, between the Company and Wilmington Trust Company, as Trustee.(o)
4.10	First Amendment, dated as of October 16, 2001, to Guarantee Agreement dated as of April 25, 2001, between the Company and Wilmington Trust Company, as Trustee.(l)
4.11	Indenture dated as of October 18, 2001, between Calpine Canada Energy Finance II ULC and Wilmington Trust Company, as Trustee.(l)
4.12	First Supplemental Indenture, dated as of October 18, 2001, between Calpine Canada Energy Finance II ULC and Wilmington Trust Company, as Trustee.(1)
4.13	Guarantee Agreement dated as of October 18, 2001, between the Company and Wilmington Trust Company, as Trustee.(l)
4.14	First Amendment, dated as of October 18, 2001, to Guarantee Agreement dated as of October 18, 2001, between the Company and Wilmington Trust Company, as Trustee.(l)
4.15	Amended and Restated Rights Agreement, dated as of September 19, 2001, between Calpine Corporation and Equiserve Trust Company, N.A., as Rights Agent.(n)
4.16	Form of Exchangeable Share Provisions and Other Provisions to Be Included in the Articles of Calpine Canada Holdings Ltd. (included as Exhibit B to Exhibit 10.1.1).(d)
4.17	Form of Support Agreement between the Company and Calpine Canada Holdings Ltd. (included as Exhibit C to Exhibit 10.1.1).(d)
4.18	HIGH TIDES I.
4.18.1	Certificate of Trust of Calpine Capital Trust, a Delaware statutory trust, dated September 29, 1999.(p)
4.18.2	Corrected Certificate of Certificate of Trust of Calpine Capital Trust, a Delaware statutory trust, filed October 4, 1999.(p)
4.18.3	Declaration of Trust of Calpine Capital Trust, dated as of October 4, 1999, among Calpine Corporation, as Depositor, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein.(p)
4.18.4	Indenture, dated as of November 2, 1999, between Calpine Corporation and The Bank of New York, as Trustee, including form of Debenture.(p)
4.18.5	Remarketing Agreement, dated November 2, 1999, among Calpine Corporation, Calpine Capital Trust, The Bank of New York, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(p)

Exhibit Number	Description
4.18.6	Amended and Restated Declaration of Trust of Calpine Capital Trust, dated as of November 2, 1999, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, and The Bank of New York, as Property Trustee, and the Administrative Trustees named therein, including form of Preferred Security and form of Common Security.(p)
4.18.7	Preferred Securities Guarantee Agreement, dated as of November 2, 1999, between Calpine Corporation and The Bank of New York, as Guarantee Trustee.(p)
4.19	HIGH TIDES II.
4.19.1	Certificate of Trust of Calpine Capital Trust II, a Delaware statutory trust, filed January 25, 2000.(q)
4.19.2	Declaration of Trust of Calpine Capital Trust II, dated as of January 24, 2000, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein.(q)
4.19.3	Indenture, dated as of January 31, 2000, between Calpine Corporation and The Bank of New York, as Trustee, including form of Debenture.(q)
4.19.4	Remarketing Agreement, dated as of January 31, 2000, among Calpine Corporation, Calpine Capital Trust II, The Bank of New York, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(q)
4.19.5	Registration Rights Agreement, dated January 31, 2000, among Calpine Corporation, Calpine Capital Trust II, Credit Suisse First Boston Corporation and ING Barings LLC.(q)
4.19.6	Amended and Restated Declaration of Trust of Calpine Capital Trust II, dated as of January 31, 2000, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein, including form of Preferred Security and form of Common Security.(q)
4.19.7	Preferred Securities Guarantee Agreement, dated as of January 31, 2000, between Calpine Corporation and The Bank of New York, as Guarantee Trustee.(q)
4.20	HIGH TIDES III.
4.20.1	Amended and Restated Certificate of Trust of Calpine Capital Trust III, a Delaware statutory trust, filed July 19, 2000.(r)
4.20.2	Declaration of Trust of Calpine Capital Trust III dated June 28, 2000, among the Company, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee and the Administrative Trustees named therein.(r)
4.20.3	Amendment No. 1 to the Declaration of Trust of Calpine Capital Trust III dated July 19, 2000, among the Company, as Depositor and Debenture Issuer, Wilmington Trust Company, as Delaware Trustee, Wilmington Trust Company, as Property Trustee, and the Administrative Trustees named therein.(r)
4.20.4	Indenture dated as of August 9, 2000, between the Company and Wilmington Trust Company, as Trustee.(r)
4.20.5	Remarketing Agreement dated as of August 9, 2000, among the Company, Calpine Capital Trust III, Wilmington Trust Company, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(r)
4.20.6	Registration Rights Agreement dated as August 9, 2000, between the Company, Calpine Capital Trust III, Credit Suisse First Boston Corporation, ING Barings LLC and CIBC World Markets Corp.(r)
4.20.7	Amended and Restated Declaration of Trust of Calpine Capital Trust III dated as of August 9, 2000, the Company, as Depositor and Debenture Issuer, Wilmington Trust Company, as Delaware Trustee, Wilmington Trust Company, as Property Trustee, and the Administrative Trustees named therein, including the form of Preferred Security and form of Common Security.(r)

Exhibit Number	Description
4.20.8	Preferred Securities Guarantee Agreement dated as of August 9, 2000, between the Company, as Guarantor, and Wilmington Trust Company, as Guarantee Trustee.(r)
4.21	PASS THROUGH CERTIFICATES (TIVERTON AND RUMFORD).
4.21.1	Pass Through Trust Agreement dated as of December 19, 2000, among Tiverton Power Associates Limited Partnership, Rumford Power Associates Limited Partnership and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of Certificate.(b)
4.21.2	Participation Agreement dated as of December 19, 2000, among the Company, Tiverton Power Associates Limited Partnership, Rumford Power Associates Limited Partnership, PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee.(b)
4.21.3	Appendix A — Definitions and Rules of Interpretation.(b)
4.21.4	Indenture of Trust, Mortgage and Security Agreement, dated as of December 19, 2000, between PMCC Calpine New England Investment LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, including the forms of Lessor Notes.(b)
4.21.5	Calpine Guaranty and Payment Agreement (Tiverton) dated as of December 19, 2000, by Calpine, as Guarantor, to PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(b)
4.21.6	Calpine Guaranty and Payment Agreement (Rumford) dated as of December 19, 2000, by Calpine, as Guarantor, to PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(b)
4.22	PASS THROUGH CERTIFICATES (SOUTH POINT, BROAD RIVER AND ROCKGEN).
4.22.1	Pass Through Trust Agreement A dated as of October 18, 2001, among South Point Energy Center, LLC, Broad River Energy LLC, RockGen Energy LLC and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of 8.400% Pass Through Certificate, Series A.(*)
4.22.2	Pass Through Trust Agreement B dated as of October 18, 2001, among South Point Energy Center, LLC, Broad River Energy LLC, RockGen Energy LLC and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of 9.825% Pass Through Certificate, Series B.(*)
4.22.3	Participation Agreement (SP-1) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.4	Participation Agreement (SP-2) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.5	Participation Agreement (SP-3) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)

Exhibit Number	Description
4.22.6	Participation Agreement (SP-4) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.7	Participation Agreement (BR-1) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.8	Participation Agreement (BR-2) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.9	Participation Agreement (BR-3) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.10	Participation Agreement (BR-4) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.11	Participation Agreement (RG-1) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.12	Participation Agreement (RG-2) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.13	Participation Agreement (RG-3) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)

Exhibit Number	Description
4.22.14	Participation Agreement (RG-4) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation. (*)
4.22.15	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes. (*)
4.22.16	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes. (*)
4.22.17	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes. (*)
4.22.18	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes. (*)
4.22.19	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes. (*)
4.22.20	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes. (*)
4.22.21	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes. (*)
4.22.22	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes. (*)
4.22.23	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes. (*)
4.22.24	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes. (*)
4.22.25	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes. (*)

Exhibit Number	Description
4.22.26	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(*)
4.22.27	Calpine Guaranty and Payment Agreement (South Point SP-1) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.28	Calpine Guaranty and Payment Agreement (South Point SP-2) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.29	Calpine Guaranty and Payment Agreement (South Point SP-3) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.30	Calpine Guaranty and Payment Agreement (South Point SP-4) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.31	Calpine Guaranty and Payment Agreement (Broad River BR-1) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.32	Calpine Guaranty and Payment Agreement (Broad River BR-2) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.33	Calpine Guaranty and Payment Agreement (Broad River BR-3) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.34	Calpine Guaranty and Payment Agreement (Broad River BR-4) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.35	Calpine Guaranty and Payment Agreement (RockGen RG-1) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.36	Calpine Guaranty and Payment Agreement (RockGen RG-2) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.37	Calpine Guaranty and Payment Agreement (RockGen RG-3) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.38	Calpine Guaranty and Payment Agreement (RockGen RG-4) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)

Exhibit Number	Description
9.1	Form of Voting and Exchange Trust Agreement between the Company, Calpine Canada Holdings Ltd. and CIBC Mellon Trust Company, as Trustee (included as Exhibit D to Exhibit 10.1.1).(d)
10.1	Purchase Agreements.
10.1.1	Combination Agreement, dated as of February 7, 2001, by and between the Company and Encal Energy Ltd.(d)
10.1.2	Amending Agreement to the Combination Agreement, dated as of March 16, 2001, between the Company and Encal Energy Ltd.(t)
10.1.3	Form of Plan of Arrangement Under Section 186 of the Business Corporations Act (Alberta) Involving and Affecting Encal Energy Ltd. and the Holders of its Common Shares and Options (included as Exhibit A to Exhibit 10.1.1).(d)
10.2	Financing Agreements.
10.2.1	Amended and Restated Calpine Construction Finance Company Financing Agreement ("CCFC I"), dated as of February 15, 2001.(d)(u)
10.2.2	Calpine Construction Finance Company Financing Agreement ("CCFC II"), dated as of October 16, 2000.(b)(v)
10.2.3	Second Amended and Restated Credit Agreement, dated as of May 23, 2000 ("Second Amended and Restated Credit Agreement"), among the Company, Bayerische Landesbank, as Co-Arranger and Syndication Agent, The Bank of Nova Scotia, as Lead Arranger and Administrative Agent, and the Lenders named therein.(w)
10.2.4	First Amendment and Waiver to Second Amended and Restated Credit Agreement, dated as of April 19, 2001, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(*)
10.2.5	Second Amendment to Second Amended and Restated Credit Agreement, dated as of March 8, 2002, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(*)
10.2.6	Credit Agreement, dated as of March 8, 2002, among the Company, the Lenders named therein, The Bank of Nova Scotia and Bayerische Landesbank Girozentrale, as lead arrangers and bookrunners, Salomon Smith Barney Inc. and Deutsche Banc Alex. Brown Inc., as lead arrangers and bookrunners, Bank of America, National Association, and Credit Suisse First Boston, Cayman Islands Branch, as lead arrangers and syndication agents, TD Securities (USA) Inc., as lead arranger, The Bank of Nova Scotia, as joint administrative agent and funding agent, and Citicorp USA, Inc., as joint administrative agent.(*)
10.2.7	Assignment and Security Agreement, dated as of March 8, 2002, by the Company in favor of The Bank of Nova Scotia, as administrative agent for each of the Lender Parties named therein.(*)
10.2.8	Pledge Agreement, dated as of March 8, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent for the Lender Parties named therein.(*)
10.2.9	Pledge Agreement, dated as of March 8, 2002, by Quintana Minerals (USA), Inc., JOQ Canada, Inc. and Quintana Canada Holdings, LLC in favor of The Bank of Nova Scotia, as Agent for the Lender Parties named therein.(*)
10.2.10	Guarantee, dated as of March 8, 2002, by Quintana Minerals (USA), Inc., JOQ Canada, Inc. and Quintana Canada Holdings, LLC, in favor of each of the Lender Parties named therein.(*)
10.3	Other Agreements.
10.3.1	Calpine Corporation Stock Option Program and forms of agreements there under.(x)(z)
10.3.2	Calpine Corporation 1996 Stock Incentive Plan and forms of agreements there under.(y)(z)
10.3.3	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Peter Cartwright.(q)(z)
10.3.4	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Ms. Ann B. Curtis.(*)(z)
10.3.5	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Ron A. Walter.(*)(z)

Exhibit Number	Description
10.3.6	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Robert D. Kelly.(*)(z)
10.3.7	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Thomas R. Mason.(*)(z)
10.3.8	Calpine Corporation Annual Management Incentive Plan.(s)(z)
10.3.9	$500,000 Promissory Note Secured by Deed of Trust made by Thomas R. Mason and Debra J. Mason in favor of Calpine Corporation.(s)(z)
10.4.1	Form of Indemnification Agreement for directors and officers.(y)(z)
10.4.2	Form of Indemnification Agreement for directors and officers.(*)(z)
12.1	Statement on Computation of Ratio of Earnings to Fixed Charges.(*)
16.1	Letter re Change in Certifying Public Accountant.(*)
21.1	Subsidiaries of the Company.(*)
23.1	Consent of Arthur Andersen LLP, Independent Public Accountants.(*)
23.2	Consent of Ernst & Young LLP, Independent Chartered Accountants.(*)
23.3	Consent of Netherland, Sewell & Associates, Inc., independent engineer.(*)
23.4	Consent of Gilbert Laustsen Jung Associates, Ltd., independent engineer.(*)
24.1	Power of Attorney of Officers and Directors of Calpine Corporation (set forth on the signature pages of this report).(*)
99.1	Letter pursuant to Temporary Note 3T to Article 3 of Regulation S-X.(*)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CALPINE CORPORATION

By: /s/ ROBERT D. KELLY

Robert D. Kelly
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: March 28, 2002

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS: That the undersigned officers and directors of Calpine Corporation do hereby constitute and appoint Peter Cartwright and Ann B. Curtis, and each of them, the lawful attorney and agent or attorneys and agents with power and authority to do any and all acts and things and to execute any and all instruments which said attorneys and agents, or either of them, determine may be necessary or advisable or required to enable Calpine Corporation to comply with the Securities and Exchange Act of 1934, as amended, and any rules or regulations or requirements of the Securities and Exchange Commission in connection with this Form 10-K Annual Report. Without limiting the generality of the foregoing power and authority, the powers granted include the power and authority to sign the names of the undersigned officers and directors in the capacities indicated below to this Form 10-K Annual Report or amendments or supplements thereto, and each of the undersigned hereby ratifies and confirms all that said attorneys and agents, or either of them, shall do or cause to be done by virtue hereof. This Power of Attorney may be signed in several counterparts.

IN WITNESS WHEREOF, each of the undersigned has executed this Power of Attorney as of the date indicated opposite the name.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ PETER CARTWRIGHT Peter Cartwright	Chairman, President, Chief Executive and Director (Principal Executive Officer)	March 28, 2002
/s/ ANN B. CURTIS Ann B. Curtis	Executive Vice President, Vice Chairman and Director	March 28, 2002
/s/ ROBERT D. KELLY Robert D. Kelly	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 28, 2002

Signature	Title	Date
/s/ CHARLES B. CLARK, JR. Charles B. Clark, Jr.	Senior Vice President and Corporate Controller (Principal Accounting Officer)	March 28, 2002
/s/ KENNETH DERR Kenneth Derr	Director	March 28, 2002
/s/ JEFFREY E. GARTEN Jeffrey E. Garten	Director	March 28, 2002
/s/ GERALD GREENWALD Gerald Greenwald	Director	March 28, 2002
Susan C. Schwab	Director	
/s/ GEORGE J. STATHAKIS George J. Stathakis	Director	March 28, 2002
John O. Wilson	Director	

CALPINE CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND OTHER INFORMATION

December 31, 2001

CALPINE CORPORATION AND SUBSIDIARIES

SELECTED CONSOLIDATED FINANCIAL DATA

	Years Ended December 31,				
	1997	1998	1999	2000	2001
	(In thousands, except earnings per share and ratio data)				
Statement of operations data(1):					
Electric generation and marketing revenue	$ 237,277	$ 511,360	$ 783,482	$ 2,072,974	$ 6,586,685
Oil and gas production and marketing revenue	95,282	101,921	155,983	444,462	948,177
Income from unconsolidated investments in power projects	15,819	25,240	36,593	24,639	8,763
Other revenue	23,140	12,125	7,426	5,026	46,353
Total revenue	371,518	650,646	983,484	2,547,101	7,589,978
Cost of revenue	236,974	466,026	664,649	1,700,133	6,258,458
Gross profit	134,544	184,620	318,835	846,968	1,331,520
Project development expense	7,537	7,165	10,712	27,556	35,860
General and administrative expense	21,604	30,024	55,667	102,551	157,370
Merger expense	—	—	—	—	41,627
Income from operations	105,403	147,431	252,456	716,861	1,096,663
Interest expense	66,787	95,732	103,248	74,683	165,360
Distributions on trust preferred securities	—	—	2,565	44,210	61,334
Interest income and other	(14,744)	(8,642)	(29,215)	(40,678)	(116,354)
Income before provision for income taxes	53,360	60,341	175,858	638,646	986,323
Provision for income taxes	20,035	21,183	68,058	264,809	345,261
Income before extraordinary gain/(charge) and cumulative effect of a change in accounting principle	33,325	39,158	107,800	373,837	641,062
Extraordinary gain/(charge), net of (tax)/benefit of $—, $441, $793, $796 and $(3,606)	—	(641)	(1,150)	(1,235)	6,007
Cumulative effect of a change in accounting principle	—	—	—	—	1,036
Net income	$ 33,325	$ 38,517	$ 106,650	$ 372,602	$ 648,105
Basic earnings per common share:					
Weighted average shares of common stock outstanding	175,159	176,725	225,375	281,070	303,522
Income before extraordinary gain/(charge) and cumulative effect of a change in accounting principle	$ 0.19	$ 0.22	$ 0.48	$ 1.33	$ 2.11
Extraordinary gain/(charge)	$ —	$ —	$ (0.01)	$ —	$ 0.02
Cumulative effect of a change in accounting principle	$ —	$ —	$ —	$ —	$ 0.01
Net income	$ 0.19	$ 0.22	$ 0.47	$ 1.33	$ 2.14

(The information contained in the Selected Financial Data is derived from the audited Consolidated Financial Statements of Calpine Corporation and Subsidiaries.)

	Years Ended December 31,				
	1997	1998	1999	2000	2001
	(In thousands, except earnings per share and ratio data)				
Diluted earnings per common share:					
Weighted average shares of common stock outstanding before dilutive effect of certain convertible securities	184,601	185,067	238,706	297,507	317,919
Income before dilutive effect of certain convertible securities, extraordinary gain/(charge) and cumulative effect of a change in accounting principle	$ 0.18	$ 0.21	$ 0.45	$ 1.26	$ 2.02
Dilutive effect of certain convertible securities(2)	$ —	$ —	$ —	$ (0.06)	$ (0.17)
Income before extraordinary gain/(charge) and cumulative effect of a change in accounting principle	$ 0.18	$ 0.21	$ 0.45	$ 1.20	$ 1.85
Extraordinary gain/(charge)	$ —	$ —	$ —	$ (0.01)	$ 0.02
Cumulative effect of a change in accounting principle	$ —	$ —	$ —	$ —	$ —
Net income	$ 0.18	$ 0.21	$ 0.45	$ 1.19	$ 1.87
Balance sheet data:					
Cash and cash equivalents	$ 48,513	$ 96,532	$ 349,371	$ 596,077	$ 1,525,417
Property, plant and equipment, net	981,615	1,372,319	3,276,180	7,979,160	15,384,990
Investments in power projects	222,542	221,509	243,225	205,621	378,614
Derivative assets	—	—	—	—	1,328,114
Total assets	1,643,192	2,032,009	4,400,902	10,323,203	21,309,295
Short-term debt	112,966	5,450	47,470	61,558	903,444
Long-term debt	843,268	1,211,377	2,214,921	4,689,562	11,824,417
Derivative liabilities	—	—	—	—	1,448,187
Total debt	956,234	1,216,827	2,262,391	4,751,120	12,727,861
Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts	—	—	270,713	1,122,490	1,123,024
Minority interests	—	—	61,705	37,576	47,389
Stockholders' equity	370,658	402,710	1,100,089	2,422,097	3,010,569
Cash flow data:					
Cash provided by operating activities	$ 148,507	$ 199,709	$ 314,361	$ 802,550	$ 557,198
Cash used in investing activities	(496,393)	(488,834)	(1,599,456)	(3,752,657)	(7,500,518)
Cash provided by financing activities	300,429	337,144	1,537,934	3,196,813	7,876,325
Effect of exchange rate changes on cash and cash equivalents	—	—	—	—	(3,665)
Net increase(decrease) in cash and cash equivalents	$ (47,457)	$ 48,019	$ 252,839	$ 246,706	$ 929,340

(The information contained in the Selected Financial Data is derived from the audited Consolidated Financial Statements of Calpine Corporation and Subsidiaries.)

	Years Ended December 31,				
	1997	1998	1999	2000	2001
	(In thousands, except earnings per share and ratio data)				
Reconciliation of net income to EBITDA, as adjusted:					
Net income	$ 33,325	$ 38,517	$ 106,650	$ 372,602	$ 648,105
Income from unconsolidated investment in power projects	(15,819)	(25,240)	(36,593)	(24,639)	(8,763)
Distributions from unconsolidated investments in power projects	21,042	27,717	43,318	29,979	5,983
Adjusted net income	38,548	40,994	113,375	377,942	645,325
Interest expense	66,787	95,732	103,248	74,683	165,360
1/3 of operating lease expense	4,677	5,710	11,198	23,140	39,624
Distributions on trust preferred securities	—	—	2,565	44,210	61,334
Provision for income taxes	20,035	21,183	68,058	264,809	345,261
Depreciation, depletion and amortization	90,871	118,873	134,907	230,787	338,244
EBITDA, as adjusted(3)	$ 220,918	$ 282,492	$ 433,351	$ 1,015,571	$ 1,595,148
Other financial data and ratios:					
Ratio of earnings to fixed charges(4)	1.68x	1.52x	1.83x	2.26x	1.64x

(1) Certain prior years' amounts have been reclassified to conform to the 2001 presentation.

(2) Includes the effect of the assumed conversion of certain convertible securities. For the years 2000 and 2001, respectively, the assumed conversion calculation adds 31,746 and 54,183 shares of common stock and $20,841 and $45,898 to the net income results, representing the after tax expense on certain convertible securities avoided upon conversion.

(3) This non-GAAP measure is defined as net income less income from unconsolidated investments, plus cash received from unconsolidated investments, plus provision for tax, plus interest expense, plus one-third of operating lease expense, plus depreciation and amortization, plus distributions on our Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts ("HIGH TIDES"). EBITDA, as adjusted is presented not as a measure of operating results, but rather as a measure of our ability to service debt. EBITDA, as adjusted should not be construed as an alternative to either (i) income from operations (determined in accordance with generally accepted accounting principles) or (ii) cash flows from operating activities (determined in accordance with generally accepted accounting principles). Prior to 2000, EBITDA, as adjusted had been calculated according to an indenture definition. EBITDA, as adjusted for 1997 through 1999 has been restated to conform to the definition set forth above.

(4) For purposes of computing our consolidated ratio of earnings to fixed charges, earnings consist of pre-tax income before adjustment for minority interests in our consolidated subsidiaries or income or loss from equity investees, plus fixed charges, amortization of capitalized interest, and distributed income of equity investees, reduced by interest capitalized and the minority interest in pre-tax income of subsidiaries that have not incurred fixed charges. Fixed charges consist of interest expensed and capitalized (including amortized premiums, discounts and capitalized expenses related to indebtedness), an estimate of the interest within rental expense and the distributions on our HIGH TIDES.

(The information contained in the Selected Financial Data is derived from the audited Consolidated Financial Statements of Calpine Corporation and Subsidiaries.)

CALPINE CORPORATION AND SUBSIDIARIES

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

In addition to historical information, this report contains forward-looking statements. Such statements include those concerning Calpine Corporation's ("the Company's") expected financial performance and its strategic and operational plans, as well as all assumptions, expectations, predictions, intentions or beliefs about future events. You are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties that could cause actual results to differ materially from the forward-looking statements such as, but not limited to, (i) unseasonable weather patterns that reduce demand for power and natural gas, (ii) systemic economic slowdowns, which can adversely affect consumption of power by businesses and consumers, (iii) the timing and extent of deregulation of energy markets and the rules and regulations adopted on a transitional basis with respect thereto, (iv) the timing and extent of changes in commodity prices for energy, particularly natural gas and electricity, (v) commercial operations of new plants that may be delayed or prevented because of various development and construction risks, such as a failure to obtain financing and the necessary permits to operate or the failure of third-party contractors to perform their contractual obligations, (vi) cost estimates are preliminary and actual costs may be higher than estimated, (vii) a competitor's development of a lower-cost gas-fired power plant, (viii) risks associated with marketing and selling power from power plants in the newly-competitive energy market, or (ix) the successful exploitation of an oil or gas resource that ultimately depends upon the geology of the resource, the total amount and cost to develop recoverable reserves, and operational factors relating to the extraction of natural gas. All information set forth in this filing is as of March 29, 2002, and Calpine undertakes no duty to update this information. Readers should carefully review the "Risk Factors" section of this document as well as in other documents filed with the Securities and Exchange Commission, including, but not limited to, the Quarterly Reports on Form 10-Q to be filed by the Company in fiscal year 2002.

Overview

Calpine Corporation ("Calpine"), a Delaware corporation, and subsidiaries (collectively, "the Company") is engaged in the generation of electricity in the United States, Canada and the United Kingdom. We are involved in the development, acquisition, ownership and operation of power generation facilities and the sale of electricity and its by-product, thermal energy, primarily in the form of steam. We have ownership interests in and operate gas-fired power generation and cogeneration facilities, gas fields, gathering systems and gas pipelines, geothermal steam fields and geothermal power generation facilities in the United States. In Canada we have power facilities and oil and gas operations. In the United Kingdom we own the Saltend Energy Centre. Each of the generation facilities produces and markets electricity for sale to utilities and other third party purchasers. Thermal energy produced by the gas-fired cogeneration facilities is primarily sold to governmental and industrial users. Gas produced and not physically delivered to our generating plants is sold to third parties. At March 20, 2002, we had interests in 64 operating power plants, representing 12,090 megawatts of net capacity. See "Item 1 — Business — Overview"

Selected Operating Information

Set forth below is certain selected operating information for our power plants and, through May 1999 for our geothermal steam fields at The Geysers, for which results are consolidated in our statements of operations. Results vary for the twelve months ended December 31, 2001, as compared to the same period in 2000 and 1999, primarily due to the consolidation of acquisitions, changing energy pricing, and increased production. Electricity revenue is composed of fixed capacity payments, which are not related to production, and variable energy payments, which are related to production. Capacity revenues include, besides traditional capacity payments, other revenues such as Reliability Must Run and Ancillary Service revenues. The information set forth under thermal and other revenue consists of host steam sales and other thermal revenue, including our geothermal steam field revenues prior to our acquisition of the PG&E geothermal power plants at The Geysers on May 7, 1999.

	Years Ended December 31,				
	1997	1998	1999	2000	2001
	(Dollars in thousands, except production and pricing data)				
Power Plants:					
Electricity and steam ("E&S") revenues:					
Energy	$ 116,577	$ 334,549	$ 458,593	$ 1,220,718	$ 1,724,830
Capacity	$ 75,588	$ 123,380	$ 247,620	$ 382,478	$ 569,231
Thermal and other	$ 45,112	$ 49,968	$ 54,112	$ 99,297	$ 138,217
Subtotal	$ 237,277	$ 507,897	$ 760,325	$ 1,702,493	$ 2,432,278
Spread on sales of purchased power(1)	$ —	$ 334	$ 2,476	$ 11,933	$ 337,583
Adjusted E&S revenues	$ 237,277	$ 508,231	$ 762,801	$ 1,714,426	$ 2,769,861
Megawatt hours produced	2,158,008	9,864,080	14,802,709	22,749,588	43,542,293
All-in electricity price per megawatt hour generated	$ 109.95	$ 51.52	$ 51.53	$ 75.36	$ 63.61

(1) From hedging, balancing and optimization activities related to our generating assets.

Set forth below is a table summarizing the dollar amounts and percentages of our total revenue for the years ended December 31, 2001, 2000, and 1999 that represent purchased power and purchased gas sales and the costs we incurred to purchase the power and gas that we resold during these periods (in thousands, except for percentage data):

	Year Ended December 31,		
	1999	2000	2001
Total revenue	$983,484	$2,547,101	$7,589,978
Sales of purchased power	23,157	370,481	4,056,354
As a percentage of total revenue	2.4%	14.5%	53.4%
Sale of purchased gas	14,416	108,329	520,723
As a percentage of total revenue	1.5%	4.3%	6.9%
Total cost of revenue ("COR")	664,649	1,700,133	6,258,458
Purchased power expense	20,681	358,649	3,708,845
As a percentage of total COR	3.1%	21.1%	59.3%
Purchased gas expense	12,646	108,331	492,587
As a percentage of total COR	1.9%	6.4%	7.9%

The primary reasons for the significant increase in these sales and costs of revenue in 2001 as compared with 2000 are: (a) the growth of Calpine Energy Services ("CES") in 2001 as compared with 2000 and the corresponding increase in hedging, balancing, optimization, and trading activities; (b) particularly volatile markets and high prices for electricity and natural gas, which prompted us to frequently adjust our hedge positions by buying power and gas and reselling it; (c) the accounting requirements under SAB 101 and EITF 99-19, which require us to show most of our hedging contracts on a gross basis (as opposed to netting sales and cost of revenue); and (d) rules in effect throughout 2001 associated with the NEPOOL market in New England, which require that all power generated in NEPOOL be sold directly to the Independent System Operator ("ISO") in that market; we then buy from the ISO to serve our customer contracts. Generally accepted accounting principles require us to account for this activity, which applies to three of our merchant generating facilities, as the aggregate of two distinct sales and one purchase. This gross basis presentation increases revenues but not gross profit. The table below details the financial extent of our transactions with NEPOOL for the period indicated. The total purchases and sales do not constitute the total amount of the gross up effect of NEPOOL transactions on our financial statements but, rather, we are supplying this information to give an indication of the extent of our transactions with NEPOOL. The increase in 2001 is primarily due to our entrance into the NEPOOL market, which began with our acquisition of the Dighton, Tiverton, and Rumford facilities on December 15, 2000.

	Year Ended December 31,		
	1999	2000	2001
		(In thousands)	
Sales to NEPOOL from power we generated	$ —	$8,511	$285,706
Sales to NEPOOL from hedging and other activity	—	—	165,416
Total sales to NEPOOL	$ —	$8,511	$451,122
Total purchases from NEPOOL	$ —	$ —	$413,875

Results of Operation

Year Ended December 31, 2001, Compared to Year Ended December 31, 2000

Revenue — Total revenue increased to $7,590.0 million for the twelve months ended December 31, 2001, compared to $2,547.1 million for the same period in 2000.

Electric generation and marketing revenue increased to $6,586.7 million in 2001 compared to $2,073.0 million in 2000. Approximately $729.8 million of the $4,513.7 million variance was due to electricity and steam sales, which increased due to our growing portfolio. Electric power generation of 43.5 million megawatt-hours in 2001 exceeded the 22.7 million megawatt-hours in 2000 by 92% which offset a decrease of $11.75 in the average all-in electricity price per megawatt-hour generated. Our revenue for the year ended December 31, 2001, includes the consolidated results of additional facilities that we acquired or completed construction during 2001. Similarly, this year's results benefited from a full year of production from facilities that we acquired at various times during 2000. Our power marketing activities contributed an increase of $3,685.9 million due to increased hedging, balancing, optimization, and trading activity as a result of the growth of CES and our operating plant portfolio during 2001 and also reflects the significant volatility in commodity pricing which led to a high volume of hedging and hedge adjusting activity.

We also recognized $98.1 million (net of a reserve of $13.1 million) in mark-to-market gains on power derivatives. This reserve is related to gains generated by Enron's insolvency which required earnings recognition for contracts that had previously been exempted from SFAS No. 133 accounting as normal purchases or sales, and which represented the change in fair value of cash flow hedges between the ineffectiveness date and the date of termination. The reserve equals 100% of the net mark-to-market gain that would have otherwise been recognized. The reserve was established due to the uncertainty surrounding the termination and settlement of the Enron contracts and will be reevaluated as we complete the Enron settlement process.

Approximately $68.5 million of the $98.1 million of the mark-to-market gain was recognized in the second quarter of 2001 from entering into a fixed price firm-quantity power sales contract for 2002 - 2006 with one counterparty in a market area where we will not have generating assets for at least the first six months of the contract. The contract presented us with an opportunity to establish a commercial relationship with an important customer in a market where we will eventually have generation assets, and we determined there was substantial benefit in executing the agreement for the entire term requested by the counterparty as opportunities to enter into such contract may be available infrequently. Because of the structure of the contract, under SFAS No. 133 the contract and the related commodity derivative transactions did not constitute a hedge or a normal purchase or sale. Before taking into account time value of money considerations, the aggregate gain was $79.9 million. At September 30, 2001, this gain was locked in as a result of entering into offsetting fixed price power purchases. However, on December 10, 2001, we terminated the portion of those offsetting purchases where Enron was the counterparty, which constituted approximately

30% of the power purchases. We have completed the process of replacing these contracts. At March 20, 2002, we had replaced 100% of the terminated volume. Our future expansion plans may result in our entry into new markets, which could present similar opportunities, and any resulting power and gas contracts will require similar accounting treatment.

Oil and gas production and marketing revenue increased to $948.2 million in 2001 compared to $444.5 million in 2000. Approximately $412.4 million of the increase relates to purchased gas sold to third parties in hedging, balancing, optimization, and trading transactions. Additionally, approximately $91.3 million of the variance relates to increased production and commodity prices in sales to third parties from our reserves in Canada and in the United States.

Income from unconsolidated investments in power projects decreased to $8.8 million in 2001 compared to $24.6 million during 2000. The variance is primarily due to the contractual reduction in distributions from the Sumas Power Plant of approximately $12.9 million. We also experienced a $4.1 million decrease in income from our Grays Ferry investment and $2.0 million less in income due to the sale of our Bayonne investment in March 2001.

Other revenue increased to $46.4 million in 2001 compared to $5.0 million in 2000. This increase is due primarily to $21.3 million recognized in 2001 from Power Systems Mfg., L.L.C. ("PSM"), which was acquired in December 2000, $6.9 million in revenues from our WRMS subsidiary, $5.9 million in commissioning services related to an unconsolidated construction project and a $2.0 million increase in interest income on loans to power projects.

Cost of revenue — Cost of revenue increased to $6,258.5 million in 2001 compared to $1,700.1 million in 2000. Approximately $3,350.2 million of the $4,558.4 million increase relates to the cost of power purchased by our energy services organization in hedging, balancing, optimization and trading activities. Similarly, oil and gas production and marketing expense grew by $408.2 million, largely due to a $384.3 million increase in expense for the cost of gas purchased (and resold) by our energy services organization. Fuel expense increased 82%, from $612.9 million in 2000 to $1,116.1 million in 2001, due to a 92% increase in megawatt hours generated which was partially mitigated by a 7% decrease in average fuel price, and mark-to-market gains of $36.7 million on natural gas derivatives. Depreciation, depletion and amortization expense increased by 47%, from $230.8 million in 2000 to $338.2 million in 2001, due to additional power facilities in operation in 2001 and due to $42.6 million in higher depreciation and depletion in our oil and gas operating subsidiaries. Operating lease expense increased by $49.5 million due to a full year of operating lease expense in connection with operating leases entered into or acquired for our Pasadena, Tiverton, Rumford, KIAC, West Ford Flat and Bear Canyon facilities during 2000, and additional operating lease expense for our Rockgen, South Point, and Broad River facilities for operating leases entered into in October 2001.

Project development expense — Project development expense increased 30% due to an increase in the number of projects in the early stage of development.

General and administrative expense — General and administrative expense increased 53% to $157.4 million for the year ended December 31, 2001, as compared to $102.6 million for the same period in 2000. The increase was attributable to continued growth in personnel and associated overhead costs necessary to support the overall growth in our operations and due to recent acquisitions, including power facilities and natural gas operations. The growth-induced increase was offset by a decrease in cash bonus accruals to reflect a higher mix of stock options in the Company's incentive program for management.

Merger expense — We incurred approximately $41.6 million of expense in 2001 in connection with our merger with Encal Energy Ltd. on April 19, 2001. The transaction was accounted for under the pooling-of-interests method and, accordingly, all transaction costs have been expensed as incurred and all periods presented have been restated to reflect the transaction.

Interest expense — Interest expense increased 121% to $165.4 million for the year ended December 31, 2001, from $74.7 million for the same period in 2000. Interest expense increased primarily due to a full year of interest expense in 2001 for $1.0 billion of senior notes issued in 2000, in addition to interest expense on approximately $4.0 billion, C$200 million, and £200 million of senior notes issued in 2001. The associated incremental interest expense was partially offset by interest capitalized. In 2001, total capitalized interest was $498.7 million versus $207.0 million in 2000. Capitalized interest increased between years due to the significant increase in our power plant construction program, which offset the slight decrease in our interest capitalization rate due to a decrease in market interest rates.

Distributions on trust preferred securities — Distributions on trust preferred securities increased 39% to $61.3 million in 2001 compared to $44.2 million in 2000. The increase is attributable to the issuance of additional trust preferred securities in August 2000, as well as a full period of distributions in 2001 with respect to the January 2000 trust preferred offering and the subsequent exercise of the initial purchasers' option to purchase additional securities.

Interest income — Interest income increased to $72.6 million for 2001, compared to $39.9 million for the same period in 2000. This increase is due primarily to the significantly higher cash balances that we have maintained as a result of our senior notes and convertible securities offerings in 2001, in addition to $10.3 million interest income in 2001 realized in connection with $265.6 million of Pacific Gas and Electric Company ("PG&E") pre-bankruptcy petition receivables.

Other income (expense) — Other income (expense) increased to $43.9 million in 2001 from $3.5 million in 2000. Other income in 2001 is comprised of approximately $19.4 million related to gains on the sale of non-strategic oil and gas properties and $28.1 million related to the settlement and termination of a contract with a gas supplier. Additionally, we recorded gains of $7.2 million on the sale of our interests in the Elwood development project and $11.3 million on the sale of our interest in the Bayonne Power Plant including related contingent income recognized as earned thereafter. These increases were partially offset by a $17.7 million reserve resulting from the nonperformance by a third party in delivering certain emissions reduction credits that we had purchased, and by the sale of the balance of our PG&E pre-bankruptcy petition receivables at a $9.0 million discount.

Provision for income taxes — The effective income tax rate was approximately 35% and 41.5% for 2001 and 2000, respectively, reflecting our expansion into Canada and the United Kingdom and our cross border financings, which reduced our effective tax rates.

Extraordinary gain (charge), net — The $6.0 million gain in 2001 was primarily a result of repurchasing $122.0 million aggregate principal amount of our Zero Coupon Convertible Debentures Due 2006 ("Zero Coupons"), which was comprised primarily of a $7.4 million gain from repurchasing the Zero Coupons at a discount and a partially offsetting loss due to the write off of unamortized deferred financing costs. The extraordinary gain was partially offset by extraordinary losses of $1.4 million related to the write off of unamortized deferred financing costs resulting from the repayment of $105 million in aggregate outstanding principal amount of the 9¼% Senior Notes Due 2004 and bridge credit facilities entered into in June 2001. The $1.2 million charge in 2000 represents the write-off of deferred financing costs related to the repayment of bridge financing and the Bank One, Texas, N.A. borrowing base facilities.

Cumulative effect of a change in accounting principle — The $1.0 million of additional income, net of tax, is due to the adoption in 2001 of Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," amended by SFAS No. 137 and SFAS No. 138 ("SFAS No. 133").

Year Ended December 31, 2000, Compared to Year Ended December 31, 1999

Revenue — Total revenue increased 159% to $2,547.1 million in 2000 compared to $983.5 million in 1999, primarily due to the impact of recognition of a full year's income from various assets that were acquired in 1999, recognition of a partial year's income from various assets that were acquired in 2000, increased hedging, balancing, and optimization activity, increased production, and favorable pricing.

Electric generation and marketing revenue increased 165% to $2,073.0 million in 2000 compared to $783.5 million in 1999. Approximately $269.4 million of the increase was generated by a full year's activity of our geothermal facilities, which we initially acquired in May 1999. The facilities that we acquired as part of the Cogeneration Corporation of America, Inc. acquisition in December 1999, which was later renamed

Calpine Cogeneration Corporation ("CCC"), contributed $107.2 million in 2000. Additionally, commencement of commercial operations at our Hidalgo facility and of our Pasadena expansion generated approximately $147.1 million. During 2000, our acquisitions of KIAC, Stony Brook, Auburndale, and Agnews contributed an additional $113.5 million to the overall increase in revenue. The balance was primarily due to increased production and favorable energy pricing in various markets, particularly California. Sales of purchased power increased $347.3 million due to increased Calpine Energy Services, LP ("CES") hedging, balancing, and optimization activity.

Oil and gas production and marketing revenue increased 185% to $444.5 million in 2000 compared to $156.0 million in 1999. Approximately $194.6 million of the increase was due to increased production and favorable pricing, in addition to the acquisition of Sheridan Energy, Inc. in October 1999 and several strategic gas acquisitions during 2000, including Quintana Minerals Canada Corp. and TriGas Exploration Inc. The remainder of the variance was caused by the increased CES hedging, balancing, and optimization activity.

Income from unconsolidated investments in power projects decreased 33% to $24.6 million in 2000 compared to $36.6 million in 1999. Approximately $5.2 million of the decrease is primarily attributable to the consolidation of KIAC, Stony Brook, Auburndale, and Agnews' results in electricity and steam sales as a result of our purchase of these facilities during 2000. We also recorded $8.8 million less equity income from Sumas, and $1.2 million less equity income from our investment in Bayonne. These amounts were partially offset by $4.7 million of revenue that we recorded in connection with our investment in the Grays Ferry facility that we acquired in December 1999.

Cost of revenue — Cost of revenue increased to $1,700.1 million in 2000 compared to $664.6 million in 1999, an increase of $1,035.5 million, or 156%.

Electric generation and marketing expense increased by $432.1 million to $587.2 million in 2000 compared to $155.1 million in 1999 due primarily to an increase of $337.9 million in the cost of purchased power by CES in hedging, balancing, and optimization activity, and additionally to the incremental effect of acquisitions made in 1999 such as CCC facilities and the geothermal facilities which reflect a full year of activity in 2000, and due to acquisitions made in 2000. Production royalties increased by $18.5 million to $32.3 million in 2000 compared to $13.8 million in 1999 primarily due to royalties paid to third parties in connection with geothermal energy generation.

Oil and gas production and marketing expense increased by $132.4 million to $197.8 million in 2000 compared to $65.4 million in 1999 due primarily to a $95.7 million increase in cost of gas purchased and resold as a result of increased CES hedging, balancing, and optimization activity, in addition to an increase in production combined with higher third-party facility charges.

Fuel expense increased by $344.2 million to $612.9 million in 2000 compared to $268.7 million in 1999 due primarily to the incremental effect of acquisitions made in 1999 such as the CCC facilities which reflect a full year of activity in 2000, and due to acquisitions made in 2000. Additionally, we incurred significantly higher gas prices during 2000.

Depreciation, depletion and amortization expense increased by $95.9 million to $230.8 million in 2000 compared to $134.9 million in 1999 primarily due to an approximate $63.6 million increase in depletion expense relating to our natural gas production. The remainder is substantially the result of the incremental effect of acquisitions that we made during 1999 and 2000.

Operating lease expense increased by $35.8 million to $69.4 million in 2000 compared to $33.6 million in 1999. Approximately $15.0 million was due to the lease associated with our acquisition of the remaining 50% interest in KIAC in May 2000. Another $8.7 million was due to the inclusion of a full year's operations of our geothermal facilities, $5.0 million was attributable to the Pasadena sales-leaseback that we entered into in September 2000, and $6.4 million was due to the higher contingent lease payments at our Watsonville facility.

Project development expense — Project development expense increased by $16.9 million, or 158%, in 2000 to $27.6 million compared to $10.7 million in 1999 due to heavier activities in identifying and obtaining acquisition and project development opportunities resulting from a larger number of development projects. For additional information, see "Item 1 — Business — Project Development and Acquisitions."

General and administrative expense — In 2000, general and administrative expense was $102.6 million compared to $55.7 million in 1999. The increase of 84% or $46.9 million is largely attributable to our acquisitions and continued growth in personnel and associated overhead costs necessary to support the overall growth of our operations and construction programs during this period.

Interest expense — Interest expense before capitalization of interest was $281.7 million in 2000 compared to $150.5 million in 1999, an increase of $131.2 million due to higher debt balances in 2000. Total debt increased by approximately $2.5 billion due primarily to our issuance of $1 billion of senior notes in August 2000 and due to debt acquired in connection with various acquisitions such as capital leases associated with our Hidalgo, Agnews, and Stony Brook acquisitions. After capitalization of interest on our significant construction program during this period, our interest expense decreased by approximately $28.5 million in 2000 to $74.7 million from $103.2 million in 1999.

Distributions on trust preferred securities — Distributions on trust preferred securities increased to $44.2 million in 2000 from $2.6 million in 1999, due to a full year of distributions on our HIGH TIDES issuance of November 1999, in addition to HIGH TIDES issuances in January and August 2000, respectively.

Interest income — In 2000, interest income was $39.9 million compared to $24.1 million in 1999. The increase of 66% or $15.8 million is attributable to higher average cash balances in 2000 owing to the public offerings of senior notes and common stock in August 2000 and due to the issuance of HIGH TIDES in January and August of 2000.

Provision for income taxes — The effective income tax rate was approximately 41% in 2000 compared to approximately 39% in 1999. The rate increase in 2000 is primarily attributable to a higher average tax rate based on the locations in which we operated. In 2000, our provision for federal and state income taxes totaled $264.8 million versus $68.1 million in 1999, an increase of $196.7 million, which is due primarily to higher taxable income in 2000.

Liquidity and Capital Resources

General — The latter half of 2001, and particularly the fourth quarter, saw a significant contraction in the availability of capital for participants in the energy sector. This was due to a range of factors, including uncertainty arising from the collapse of Enron. While we have continued to be able to access the capital and bank credit markets, as discussed below, we recognize that terms of available financing in the future may not be attractive to us. To protect against this possibility, we have scaled back our capital expenditure program for 2002 and 2003 to enable us to conserve our available capital resources, but remain ready to access the capital markets as attractive opportunities arise.

To date, we have obtained cash from our operations; borrowings under our credit facilities and other working capital lines; sales of debt, equity, trust preferred securities and convertible debentures; proceeds from sale/leaseback transactions and project financing. We have utilized this cash to fund our operations, service debt obligations, fund acquisitions, develop and construct power generation facilities, finance capital expenditures, support our hedging, balancing and optimization activities at CES, and meet our other cash and liquidity needs. Our business is capital intensive. Our ability to capitalize on growth opportunities is dependent on the availability of capital on attractive terms. Our strategy is also to reinvest our cash from operations into our business development and construction program, rather than to pay cash dividends.

Cash Flow Activities — The following table summarizes our cash flow activities for the periods indicated:

	Years Ended December 31, 2001	2000 (In thousands)	1999
Beginning cash and cash equivalents	$ 596,077	$ 349,371	$ 96,532
Net cash provided by:			
Operating activities	557,198	802,550	314,361
Investing activities	(7,500,518)	(3,752,657)	(1,599,456)
Financing activities	7,876,325	3,196,813	1,537,934
Effect of exchange rates changes on cash and cash equivalents	(3,665)	—	—
Net increase in cash and cash equivalents	929,340	246,706	252,839
Ending cash and cash equivalents	$ 1,525,417	$ 596,077	$ 349,371

Operating activities for 2001 provided net cash of $557.2 million, a 31% decrease from 2000, consisting of an approximately $2.0 billion increase in operating liabilities ($1.4 billion related to derivative liabilities), $369.9 million of depreciation and amortization, $648.1 million of net income, $6.0 million of distributions from unconsolidated investments in power projects, $9.8 million of minority interest, and $20.6 million of deferred income taxes. This was partially offset by $2.3 billion in increases in operating assets ($1.3 billion related to derivative assets) and $8.8 million of income from unconsolidated investments. The decrease in cash provided by operating activities in 2001 is primarily due to the pre-bankruptcy petition PG&E receivables, which were sold to a third party effective December 31, 2001, but cash was not received until the first quarter of 2002).

Investing activities for 2001 consumed net cash of $7.5 billion, primarily due to $6.2 billion for construction costs and capital expenditures including gas turbine generator costs and associated capitalized interest, $1.8 billion for acquisitions (see Note 4 of the Notes to Consolidated Financial Statements for further discussion), $149.4 million of advances to joint ventures including associated capitalized interest for investments in power projects under construction, $143.8 million of capitalized project development costs including associated capitalized interest, a $12.0 million increase in notes receivables primarily due to the PG&E note for our Gilroy Cogen facility, which is not yet due and payable and a $62.5 million increase in restricted cash. This was partially offset by $815.5 million in sale/leaseback proceeds, $49.1 million in disposals of property, plant and equipment and $4.0 in maturities of collateral securities. The increase in cash used in investing activities in 2001 is primarily due to increased construction and acquisition activity compared to 2000.

Financing activities for 2001 provided $7.9 billion of net cash consisting of $1.0 billion of proceeds from the issuance of Zero Coupons, $1.1 billion of proceeds from our issuance of Convertible Senior Notes Due 2006, $4.6 billion of proceeds from other Senior Notes offerings, $3.6 billion in additional project financing, $75.4 million from the issuance of common stock and $151.5 million in borrowings under lines of credit. This was offset by $2.3 billion of repayments on various credit facilities, $105.0 million for the redemption of the Senior Notes Due 2004, $122.0 million for repurchase of Zero Coupons, and $154.6 million of financing costs. The increase in cash provided from financing activities in 2001 is primarily due to the debt offerings in 2001.

We continue to evaluate current and forecasted cash flow as a basis for financing operating requirements and capital expenditures. We believe that we will have sufficient liquidity from cash flow from operations, borrowings available under the lines of credit, access to the capital markets and working capital to satisfy all obligations under outstanding indebtedness, to finance anticipated capital expenditures and to fund working capital requirements for the next twelve months.

PG&E and Enron Bankruptcies — In December 2001 the bankruptcy court approved an agreement between Calpine and PG&E whereby PG&E would repay the $265.6 million in past due pre-bankruptcy petition receivables plus accrued interest thereon beginning on December 31, 2001, and with monthly payments thereafter over the next 11 months. Shortly following receipt of this bankruptcy court approval and the first payments from PG&E on December 31, 2001, we sold the remaining PG&E receivables to a third party at 96.125% of face value.

As discussed in Note 18 of the Notes to Consolidated Financial Statements and under the caption "Item 1 — Business — Recent Developments", there is considerable uncertainty surrounding the Enron bankruptcy. Regardless of the resolution of the current situation, we believe, based on legal analysis, that we have no net exposure to Enron.

CES Margin Deposits and Other Credit Support — As of December 31, 2001, CES had deposited $345.5 million in cash as margin deposits with third parties related to its business activities and letters of credit outstanding in support of CES business activities of $259.4 million. As of December 31, 2000, CES had no margin deposits with third parties. The Company is evaluating various relationships with potential partners to strengthen its ability to conduct risk management activities and to support the credit requirements of its trading activities.

The amount of credit support required to support CES's operations is a function primarily of the changes in fair value of commodity contracts that CES has entered into and Calpine's credit rating. While some portion of the increased credit support requirements resulted from Calpine's credit ratings downgrades in the fourth quarter of 2001, the increases in the amount of cash margin deposits and letters of credit provided by the Company for CES' transactions in 2001 as compared with 2000 were largely due to the decrease in natural gas prices in 2001, compounded by the significantly increased volumes of trading engaged in by CES in 2001 as compared with 2000. Since December 31, 2001, however, the amount of credit support provided by the Company for CES transactions has declined, largely due to recent increases in natural gas prices during this period as compared with late 2001. While we believe that we have adequate liquidity to support CES' operations at this time, it is difficult to predict how these various factors will develop in 2002 and beyond. Therefore, no assurance can be given as to the amount of credit support that the Company may need to provide as part of its business operations.

Revised Capital Expenditure Program — Following a comprehensive review of our power plant development program, we announced in January 2002 the adoption of a revised capital expenditure program, which contemplates the completion of 27 power projects (representing 15,200 MW) currently under construction during 2002 and 2003. Three of these facilities achieved full or partial commercial operations as of March 20, 2002. Construction of an additional 34 advanced-stage development projects (representing 15,100 MW) will be placed on "hot standby" following completion of advanced development activities pending further review, reducing previously forecasted 2002 capital spending by as much as $2 billion. Construction of these advanced stage development projects is expected to proceed when there is an established market need for additional generating resources at prices that will allow us to meet our established investment criteria, and when capital is available to us on attractive terms. However, our development and construction program is flexible and subject to continuing review and revision based upon such criteria.

On March 12, 2002, we announced a new turbine program that reduces previously forecasted capital spending by approximately $1.2 billion in 2002 and $1.8 billion in 2003. The revision includes adjusted timing of turbine delivery and related payment schedules and also cancellation orders. As a result of the cancellation, we will record a pre-tax charge of $161 million in the first quarter of 2002.

Uses and Sources of Funding — Our estimated uses of funds for 2002 are as follows: construction costs of $2.5 billion, cost to repurchase the remaining Zero Coupons of $0.7 billion, maintenance and gas capital expenditures of $0.3 billion, cash lease payments of $0.3 billion, estimated Enron contract settlement payments of $0.1 billion and $0.7 billion for turbines for financeable and future projects. These uses of funds will be funded primarily through an estimated $1.2 billion of 2002 operating cash flow and by cash on hand of $1.6 billion (consists of cash on hand of $1.5 billion at December 31, 2001, $0.2 billion from the sale of the PG&E receivables, $0.1 billion from the Convertible Senior Notes offering in early January 2002 and after spending $0.2 billion for the repurchase of Zero Coupons in the open market). The other sources of funding will include $1.0 billion from the new revolver, $0.5 billion of cash collateral to be replaced with letters of credit to be issued under the new revolver and $0.6 billion from our construction revolvers and our proposed

California peaker leases. We are also negotiating the sale of non-strategic assets for approximately $0.3 billion. Other potential sources of cash include monetizing our Canadian power generation assets for approximately $0.3 billion, entering into a sale/leaseback transaction for our Zion facility for cash proceeds of $0.2 billion, the sale of our Gilroy accounts receivable for proceeds of $0.2 billion and financing for our future turbines of $0.3 billion. Actual costs for the projected use of funds identified above, and net proceeds from the projected sources of funds identified above could vary from those estimates, potentially in material respects. Factors that could affect the accuracy of these estimates include the factors identified at the beginning of this section and under "Risk Factors" below, as well as continued market impacts of the demise of Enron.

Capital Availability — Notwithstanding recent uncertainties in the domestic energy and capital markets, we have raised substantial capital. In the last quarter of 2001 and early 2002, we have raised over $5 billion of capital, including $2.6 billion in sale/leaseback transactions and senior notes issued in the U.S., Canada, the U.K. and other European markets (representing an increase in size from the $2.0 billion that we had initially sought to raise), $1.2 billion in convertible senior notes in a private placement in the U.S. (representing an increase in size from the $500 million that we had initially sought to raise), and $1.6 billion secured working capital credit facility, which closed in March 2002. Proceeds from the senior notes offerings were used to refinance bridge loans that were incurred in the third quarter of 2001 and for working capital and general corporate purposes. Proceeds from the convertible senior notes will be primarily used to retire the Zero Coupons that remain outstanding, either in open-market purchases, negotiated transactions or upon exercise by holders of the April 2002 put option. From December 2001 through February 2002 we repurchased $314.5 million in aggregate principal of the Zero Coupons.

Credit Considerations — On December 14, 2001, Moody's Investors Service ("Moody's") downgraded our long-term debt from Baa3 (its lowest investment grade rating) to Ba1 (its highest non-investment grade rating) after reviewing our near-term cashflow, liquidity sources and financial flexibility. We remain on credit watch with negative implications at Moody's. In addition, on December 19, 2001, Fitch, Inc. ("Fitch") downgraded our long-term debt from BBB− (its lowest investment grade rating) to BB+ (its highest non-investment grade rating). On March 12, 2002, Fitch further downgraded our senior unsecured debt to BB. On March 25, 2002, Standard & Poor's downgraded our corporate credit rating from BB+ to BB and our investor unsecured debt from BB+ to B+. Many other issuers in the power generation sector have also been downgraded by one or more of the ratings agencies during this period. Such downgrades can have a negative impact on our liquidity by reducing attractive financing opportunities and increasing the amount of collateral required by trading counterparties.

Performance Indicators — We believe the following factors are important in assessing our ability to continue to fund our growth in the capital markets: (a) our debt-to-capital ratio; (b) various interest coverage ratios; (c) our credit and debt ratings by the rating agencies; (d) the trading prices of our senior notes in the capital markets; (e) the price of our common stock on The New York Stock Exchange; (f) our anticipated capital requirements over the coming quarters and years; (g) the profitability of our operations; (h) our cash balances and remaining capacity under existing revolving credit construction and general purpose credit facilities; (i) compliance with covenants in existing debt facilities; (j) progress in raising new or replacement capital; and (k) the stability of future contractual cash flows. We believe that our ability to complete the financing transactions described above in difficult conditions affecting the market, and our sector, in general demonstrate our ability to have access to the capital markets on acceptable terms in the future, although availability of capital has tightened significantly throughout the power generation industry in the first quarter of 2002 and, therefore, there can be no assurance that we will have access to capital in the future as and when we may desire.

Off-Balance Sheet Commitments — In accordance with SFAS No. 13 and SFAS No. 98, "Accounting for Leases" our operating leases are not reflected on our balance sheet (see Note 21 to the Notes to Consolidated Financial Statements). We have also entered into several sale/leaseback transactions. All counterparties in these transactions are third parties that are unrelated to Calpine. The sale/leaseback transactions involving Tiverton, Rumford, South Point, Broad River, and RockGen utilize special-purpose entities formed by the equity investors with the sole purpose of owning a power generation facility (see Note 5 to the Notes to Consolidated Financial Statements). Some of the Company's operating leases contain customary restrictions on dividends, additional debt and further encumbrances similar to those typically found in project finance instruments. Calpine guarantees $3.0 billion of the total future minimum lease payments of its consolidated subsidiaries related to its operating leases. In accordance with APB Opinion No. 18 "The Equity Method of Accounting For Investments in Common Stock" and FASB Interpretation No. 35, "Criteria for Applying the Equity Method of Accounting for Investments in Common Stock (An Interpretation of APB Opinion No. 18)", the debt on the books of our unconsolidated investments in power projects is not reflected on our balance sheet (see Note 6 to the Notes to Consolidated Financial Statements). Calpine has no ownership or other interest in any of these special-purpose entities. At December 31, 2001, investee debt is approximately $737.9 million. Based on our pro rata ownership share of each of the investments, our share would be approximately $248.5 million. However, all such debt is non-recourse to us. For the Aries Power Plant construction debt, we and Aquila Energy, a wholly owned subsidiary of UtiliCorp United, have provided support arrangements until construction is completed to cover cost overruns, if any.

Two wholly-owned finance subsidiaries of Calpine, Calpine Canada Energy Finance ULC and Calpine Canada Energy Finance II ULC, issued Senior Notes in 2001 (see Note 13 to the Notes to Consolidated Financial Statements). The securities are fully and unconditionally guaranteed by Calpine.

Contractual Cash Obligations — The Company's total debt, capital lease obligations, operating leases and turbine commitments as of December 31, 2001, are as follows (in thousands):

	Payments Due by Period					
Contractual Obligations	**2002**	**2003**	**2004**	**2005**	**2006**	**Thereafter**
Total Debt	$ 901,238	$1,032,326	$2,425,834	$ 250,000	$1,521,750	$ 6,387,288
Capital Lease Obligations	2,206	2,817	3,272	3,782	5,365	191,983
Operating Leases	360,603	419,487	291,121	267,119	254,790	3,118,665
Turbine Commitments	1,148,460	629,207	1,204,717	1,172,483	752,064	181,186
HIGH TIDES	—	—	—	—	—	1,123,024
Total Contractual Obligations	$2,412,507	$2,412,507	$3,924,944	$1,693,384	$2,533,969	$11,002,146

See Notes 8 through 13 of the Notes to Consolidated Financial Statements for more information on the debt and capital lease obligations outstanding in 2000 and 2001. See Note 21 of the Notes to Consolidated Financial Statements for more information on the Company's operating leases and turbine commitments. We have substantial flexibility to cancel our turbine orders if conditions warrant.

Commercial Commitments — The Company's primary commercial obligations as of December 31, 2001, are as follows (in thousands):

		Amounts of Commitment Expiration Per Period					
Commercial Commitments	**Total Amounts Committed**	**2002**	**2003**	**2004**	**2005**	**2006**	**Thereafter**
Letters of Credit	$ 642,496	$580,883	$ 4,445	$ —	$ 57,168	$ —	$ —
Debt Guarantees	3,012,892	195,023	249,063	142,316	116,102	115,124	2,195,264
Total Commercial Commitments	$3,655,388	$775,906	$253,508	$142,316	$173,270	$115,124	$2,195,264

Our commercial commitments primarily include letters of credit and debt guarantees. The debt guarantees consist of parent guarantees for the finance subsidiaries referred to above and guarantees of portions of operating lease payments for several of our operating leases. We also issue guarantees for normal course of business activities.

Performance Metrics

In understanding our business, we believe that certain performance metrics are particularly important. These include:

- *Average gross profit margin based on pro forma (non-GAAP) revenue and pro forma (non-GAAP) cost of revenue.* A high percentage of our revenue consists of CES hedging, balancing, optimization, and trading activity undertaken primarily to enhance the value of our generating assets (see "Marketing, Hedging, Optimization, and Trading" subsection of our Business Section). CES's hedging, balancing, optimization, and trading activity is primarily accomplished by buying and selling electric power and buying and selling natural gas or by entering into gas financial instruments such as exchange-traded swaps or forward contracts. Under Staff Accounting Bulletin ("SAB") No. 101 and EITF No. 99-19, we must show the purchases and sales of electricity and gas on a gross basis in our statement of operations when we act as a principal, take title to the electricity and gas we purchase for resale, and enjoy the risks and rewards of ownership. This is notwithstanding the fact that the net gain or loss on certain financial hedging instruments, such as exchange-traded forward contracts for natural gas, is shown as a net item in our GAAP financials. Because of the inflating effect on revenue of our hedging, balancing, optimization, and trading activity, we believe that revenue levels and trends do not reflect our performance as accurately as gross profit, and that it is analytically useful to look at our results on a pro forma, non-GAAP basis with all hedging, balancing, optimization, and trading activity netted. This analytical approach nets the sales of purchased power with purchased power expense (with the exception of net realized sales and expenses on electrical trading activity, which is shown on a net basis in sales of purchased power) and includes that net amount as an adjustment to electricity and steam ("E&S") revenue for our generation assets. Similarly, we believe that it is analytically useful to net the sales of purchased gas with purchased gas expense (with the exception of net realized sales and expenses on gas trading activity, which is shown on a net basis in sales of purchased gas) and include that net amount as an adjustment to cost of oil and natural gas burned by power plants, a component of fuel expense. This allows us to look at all hedging, balancing, optimization, and trading activity consistently (net presentation) and better understand our performance trends. It should be noted that in this non-GAAP analytical approach, total gross profit does not change from the GAAP presentation, but the gross profit margins as a percent of revenue do differ from corresponding GAAP amounts because the inflating effects on our revenue of hedging, balancing, optimization, and trading activities are removed.

- *Average availability and average capacity factor or operating rate.* Availability represents the percent of total hours during the period that our plants were available to run after taking into account the downtime associated with both scheduled and unscheduled outages. The capacity factor, sometimes called operating rate, is calculated by dividing (a) total megawatt hours generated by our power plants (excluding peakers) by the product of multiplying (b) the weighted average megawatts in operation during the period by (c) the total hours in the period. The capacity factor is thus a measure of total actual generation as a percent of total potential generation. If we elect not to generate during periods when electricity pricing is too low or gas prices too high to operate profitably, the capacity factor will reflect that decision as well as both scheduled and unscheduled outages due to maintenance and repair requirements.

- *Average heat rate for gas-fired fleet of power plants expressed in Btu's of fuel consumed per kWh generated.* We calculate the average heat rate for our gas-fired power plants (excluding peakers) by dividing (a) fuel consumed in Btu's by (b) kilowatt-hours generated. The resultant heat rate is a measure of fuel efficiency, so the lower the heat rate, the better. We also calculate a "steam-adjusted" heat rate, in which we adjust the fuel consumption in Btu's down by the equivalent heat content in steam or other thermal energy exported to a third party, such as to steam hosts for our cogeneration facilities. Our goal is to have the lowest average heat rate in the industry.

- *Average all-in realized electric price expressed in dollars per MWh generated.* We calculate the all-in realized electric price per MWh generated by dividing (a) adjusted E&S revenue, which includes capacity revenues, energy revenues, thermal revenues and the spread on sales of purchased electricity for hedging, balancing, and optimization activity, by (b) total generated MWh's in the period.
- *Average cost of natural gas expressed in dollars per millions of Btu's of fuel consumed.* At Calpine, the fuel costs for our gas-fired power plants are a function of the price we pay for fuel purchased and the results of the fuel hedging, balancing, and optimization activities by CES. Accordingly, we calculate the cost of natural gas per millions of Btu's of fuel consumed in our power plants by dividing (a) adjusted cost of oil and natural gas burned by power plants which includes the cost of fuel consumed by our plants (adding back cost of intercompany "equity" gas from Calpine Natural Gas, which is eliminated in consolidation), and the spread on sales of purchased gas for hedging, balancing, and optimization activity by (b) the heat content in millions of Btu's of the fuel we consumed in our power plants for the period.
- *Average spark spread expressed in dollars per MWh generated.* Our risk management activities focus on managing the spark spread for our portfolio of power plants, the spread between the sales price for electricity generated and the cost of fuel. We calculate the spark spread per MWh generated by subtracting (a) adjusted cost of oil and natural gas burned by power plants from (b) adjusted E&S revenue and dividing the difference by (c) total generated MWh's in the period.

The table below presents, side-by-side, both our GAAP and pro forma non-GAAP netted revenue, costs of revenue and gross profit showing the purchases and sales of electricity and gas for hedging, balancing, optimization, and trading activity on a net basis. It also shows the other performance metrics discussed above.

	GAAP Presentation		Non-GAAP Netted Presentation	
	Year Ended December 31,		Year Ended December 31,	
	2001	2000	2001	2000
	(In thousands)			
Revenue, Cost of Revenue and Gross Profit				
Revenue:				
Electric generation and marketing revenue				
Electricity and steam revenue(1)	$2,432,278	$1,702,493	$2,769,861	$1,714,426
Sales of purchased power(1)	4,056,354	370,481	9,926	(101)
Electric power derivative mark-to-market gain	98,053	—	98,053	—
Total electric generation and marketing revenue	6,586,685	2,072,974	2,877,840	1,714,325
Oil and gas production and marketing revenue				
Oil and gas sales	427,454	336,133	427,454	336,133
Sales of purchased gas(1)	520,723	108,329	19,219	—
Total oil and gas production and marketing revenue	948,177	444,462	446,673	336,133
Income (loss) from unconsolidated investments in power projects	8,763	24,639	8,763	24,639
Other revenue	46,353	5,026	46,353	5,026
Total revenue	7,589,978	2,547,101	3,379,629	2,080,123
Cost of revenue:				
Electric generation and marketing expense				
Plant operating expense	327,389	196,213	327,389	196,213
Royalty expense	27,492	32,325	27,492	32,325
Purchased power expense(1)	3,708,845	358,649	—	—
Total electric generation and marketing expense	4,063,726	587,187	354,881	228,538
Oil and gas production and marketing expense				
Oil and gas production expense	113,387	89,442	113,387	89,442
Purchased gas expense(1)	492,587	108,331	—	—
Total oil and gas production and marketing expense	605,974	197,773	113,387	89,442
Fuel expense				
Cost of oil and natural gas burned by power plants(1)	1,152,785	612,947	1,143,868	612,949
Natural gas derivative mark-to-market gain	(36,693)	—	(36,693)	—
Total fuel expense	1,116,092	612,947	1,107,175	612,949
Depreciation, depletion and amortization expense	338,244	230,787	338,244	230,787
Operating lease expense	118,873	69,419	118,873	69,419
Other expense	15,549	2,020	15,549	2,020
Total cost of revenue	6,258,458	1,700,133	2,048,109	1,233,155
Gross profit	$1,331,520	$ 846,968	$1,331,520	$ 846,968
Gross profit margin	18%	33%	39%	41%

	Non-GAAP Netted Presentation	
	Year Ended December 31,	
	2001	2000
	(In thousands)	
Other Non-GAAP Performance Metrics		
Average availability and capacity factor:		
Average availability	94%	94%
Average capacity factor or operating rate based on total hours (excluding peakers)	72%	72%
Average heat rate for gas-fired power plants (excluding peakers) (Btu's/kWh):		
Not steam adjusted	8,203	9,294
Steam adjusted	7,398	7,816
Average all-in realized electric price:		
Adjusted electricity and steam revenue (in thousands)	$2,769,861	$1,714,426
MWh generated (in thousands)	43,542	22,750
Average all-in realized electric price per MWh	$ 63.61	$ 75.36
Average cost of natural gas:		
Cost of oil and natural gas burned by power plants (in thousands)	$1,143,868	$ 612,949
Fuel cost elimination	99,854	56,052
Adjusted cost of oil and natural gas burned by power plants	1,243,722	669,001
MMBtu of fuel consumed by generating plants (in thousands)	297,454	150,669
Average cost of natural gas per MMBtu	$ 4.18	$ 4.44
MWh generated (in thousands)	43,542	22,750
Average cost of oil and natural gas burned by power plants per MWh	$ 28.56	$ 29.41
Average spark spread:		
Adjusted electricity and steam revenue (in thousands)	$2,769,861	$1,714,426
Less: Adjusted cost of oil and natural gas burned by power plants (in thousands)	$1,243,723	$ 669,001
Spark spread (in thousands)	$1,526,138	$1,045,425
MWh generated (in thousands)	43,542	22,750
Average spark spread per MWh	$ 35.05	$ 45.95

The non-GAAP presentation above also facilitates a look at the total "trading" activity impact on gross profit. In 2001 trading activity consisted of:

Electricity	Electric generation and marketing revenue	
Realized gain	Sales of purchased power	$ 9,926
Unrealized	Electric power derivative mark-to-market gain	98,053
Subtotal		$107,979
Gas	Oil and gas production and marketing revenue	
Realized gain	Sales of purchased gas	$ 19,219
	Fuel Expense	
Unrealized	Natural gas derivative mark-to-market gain	36,693
Subtotal		$ 55,912

		Percent of Gross Profit
Total Trading Activity	$163,891	12.3%
Realized gains	$ 29,145	2.2%
Unrealized (mark-to-market) gains(2)	$134,746	10.1%
Trading activity in 2000 was immaterial		

(1) Following is a reconciliation of GAAP to non-GAAP presentation further to the narrative set forth under this Performance Metrics section: ($ in thousands)

	GAAP Balance	To Net Hedging, Balancing & Optimization Activity	To Net Trading Activity	Netted Non-GAAP Balance
2001				
Electricity and steam revenue	$2,432,278	$ 337,583	$ —	$2,769,861
Sales of purchased power	4,056,354	(3,324,162)	(722,267)	9,926
Sales of purchased gas	520,723	(497,283)	(4,222)	19,219
Purchased power expense	3,708,845	(2,986,578)	(722,267)	—
Purchased gas expense	492,587	(468,760)	(23,827)	—
Cost of oil and natural gas burned by power plants	1,152,785	(28,522)	19,605	1,143,868
2000				
Electricity and steam revenue	$1,702,493	$ 11,933	$ —	$1,714,426
Sales of purchased power	370,481	(370,582)	—	(101)
Sales of purchased gas	108,329	(108,329)	—	—
Purchased power expense	358,649	(358,649)	—	—
Purchased gas expense	108,331	(108,331)	—	—
Cost of oil and natural gas burned by power plants	612,947	2	—	612,949

(2) The mark-to-market gains shown above as "trading" activity includes a net loss on hedge ineffectiveness of $883, consisting of an ineffectiveness gain on power hedges of $1,866 and an ineffectiveness (loss) on gas hedges of ($2,749).

Strategy

For a discussion of the Company's strategy and management's outlook, see "Item 1 — Business — Strategy".

Risk Factors

Market

We depend on our electricity and thermal energy customers. Our systems of power generation facilities rely on one or more power sales agreements with one or more utilities or other customers for a substantial portion of our revenue. In addition, sales of electricity to one customer during 2001, Enron Corporation, comprised approximately 22% of our total revenue that year. The loss of significant power sales agreements with PG&E could have a negative effect on our results of operations. In addition, any material failure by any customer to fulfill its obligations under a power sales agreement could have a negative effect on the cash flow available to us and on our results of operations. Enron filed for protection under bankruptcy law on December 2, 2001. While this action did not directly impact our business in a materially adverse way, we and all in the industry have felt the aftermath effects in terms of constricted credit support availability for transactions with certain trading company counterparties.

Competition could adversely affect our performance. The power generation industry is characterized by intense competition, and we encounter competition from utilities, industrial companies and other independent power producers. In recent years, there has been increasing competition in an effort to obtain power sales agreements, and this competition has contributed to a reduction in electricity prices in certain markets. In addition, many states are implementing or considering regulatory initiatives designed to increase competition in the domestic power industry. In California, the CPUC issued decisions that provide for direct access for all customers as of April 1, 1998; however, the CPUC has recently suspended direct access in California effective September 20, 2001. As a result, uncertainty exists as to the future course for direct access in California in the aftermath of the energy crisis in that state. In Texas, legislation phases-in a deregulated power market commencing January 1, 2001. Regulatory initiatives are also being considered in other states, including New York and states in New England. This competition has put pressure on electric utilities to lower their costs, including the cost of purchased electricity, and increasing competition in the supply of electricity in the future will increase this pressure. See "Item 1 — Business — Recent Developments — California Power Market."

Our international investments may face uncertainties. We have investments in oil and natural gas resources and power projects in Canada in development and in operation, and an investment in a power generation facility in the U.K., and we may pursue additional international investments in the future subject to the limitations on our expansion plans due to current capital market constraints. International investments are subject to unique risks and uncertainties relating to the political, social and economic structures of the countries in which we invest. Risks specifically related to investments in non-United States projects may include:

- fluctuations in currency valuation;
- currency inconvertibility;
- expropriation and confiscatory taxation;
- increased regulation; and
- approval requirements and governmental policies limiting returns to foreign investors.

Enron Bankruptcy

During 2001, the Company, primarily through our CES subsidiary, transacted a significant volume of business with units of Enron Corp. ("Enron") mainly Enron Power Marketing, Inc. ("EPMI") and Enron North America Corp. ("ENA"). ENA is the parent corporation of EPMI. Enron is the direct or indirect parent corporation of ENA. Most of these transactions were contracts for sales and purchases of power and gas for hedging and optimization purposes, some of which extended out as far as 2009. In October and November of 2001, Enron announced a series of developments including restatement of the last four years of earnings, an investigation by the Securities and Exchange Commission relating to the adequacy of Enron's disclosures of certain off-balance sheet financial transactions or structures and dismissals of certain members of senior management. On December 2, 2001, Enron Corp. and certain of its subsidiaries filed voluntary petitions for Chapter 11 reorganization with the U.S. Bankruptcy Court for the Southern District of New York. EPMI and ENA are among the subsidiaries of Enron that filed for reorganization on December 2, 2001.

For the year ended December 31, 2001, $1.7 billion or 22% of our revenue was with Enron subsidiaries, primarily EPMI and ENA. We, primarily through our subsidiary, CES, purchased significant amounts of fuel and power from ENA and EPMI prior to the bankruptcy filings, which gave rise to current accounts payable and open contract fair value positions. For the year ended December 31, 2001, CES had power and fuel purchases from ENA and EPMI of $1.6 billion. These purchases must be included in an overall understanding of our Enron exposure. The sales to and purchases from various Enron subsidiaries were mostly hedging and optimization transactions, and in most cases the purchases and sales are not related and should not be netted to try to gauge the profitability of transactions with Enron subsidiaries.

In assessing our exposure to ENA and EPMI, we analyze our accounts receivable and accounts payable balances on contracts that have already settled and also the fair value (mark-to-market value) of the contracts that have not settled. In the event of a default by one or more of the Enron subsidiaries and affiliates, and our termination of some or all of the open contracts, we would have an exposure to realize the fair value of the positive ("in the money") contracts. In managing the overall credit exposure to each other, Calpine and Enron entered into a netting agreement in which overall mark-to-market exposures are netted or offset from all transactions between certain Enron subsidiaries and CES to liabilities between those entities.

Unrealized pre-tax losses on derivatives designated as effective cash flow hedges that were recorded in OCI associated with Enron activity for the year ended December 31, 2001, were $118.6 million. Recognized gains on derivatives not designated as hedges associated with Enron activity were $381.8 million for the year ended December 31, 2001. Recognized losses on derivatives not designated as hedges associated with Enron activity were $495.0 million for the year ended December 31, 2001. Recognized gross gains (losses) on fair value hedges (which are perfectly offset by the gains and losses on the hedged items) associated with Enron activity were $9.8 million and $(31.6) million, respectively, for the year ended December 31, 2001. As mentioned above, these transactions with Enron are generally not related to each other and should not be netted to try to guage the profitability of transactions with Enron subsidiaries.

On November 14, 2001, CES, ENA and EPMI entered into a Master Netting, Setoff and Security Agreement (the "Netting Agreement"). The Netting Agreement permits CES, on the one hand, and ENA and EPMI, on the other hand, to set off amounts owed to each other under an ISDA Master Agreement between CES and ENA, an Enfolio Master Firm Purchase/Sale Agreement between CES and ENA and a Master Energy Purchase/Sale Agreement between CES and EPMI (in each case, after giving effect to the netting provisions contained in each of these agreements).

Pursuant to the Netting Agreement, Enron's bankruptcy constituted an event of default, and CES effected an early termination of the ISDA Master Agreement, the Enfolio Master Agreement and the Master Energy Agreement on December 10, 2001. CES is presently determining its losses, damages, attorneys' fees and other expenses arising from the default by Enron and its affiliates, as it is entitled to do pursuant to the underlying documents. The Company expects that there will be a net amount payable to ENA pursuant to these agreements after giving effect to the Netting Agreement, and thus that there will be no net credit exposure to Enron and its affiliates arising from these transactions. The Company filed a copy of the Netting Agreement as an exhibit to a Current Report on Form 8-K dated November 14, 2001, and filed on January 16, 2002.

The Company believes that the Netting Agreement is enforceable in accordance with its terms, based upon the following analysis, although there can be no assurance in this regard. Section 553 of the Bankruptcy Code preserves the right of a creditor who owes a debt to the debtor to offset that debt against a debt owed by the debtor to the creditor, to the extent that such a right was in existence between the parties prior to the bankruptcy. Setoff rights will be preserved in bankruptcy, in general, where four conditions are met: (1) the creditor has a claim against the debtor that arose before the bankruptcy case was filed (a pre-petition claim); (2) the creditor owes a debt to the debtor that also arose pre-petition; (3) the claim and debt are mutual, meaning that the identical entities or individual parties must each owe the other a debt in the same capacity; and (4) the claim and debt are each valid and enforceable.

The Bankruptcy Code expressly permits the non-debtor party to certain types of contracts, such as swap contracts and forward contracts, to terminate and liquidate the contracts after the commencement of a bankruptcy case as the result of a bankruptcy default. Section 556 provides, among other things, that the contractual right of a forward contract merchant to cause the liquidation of a forward contract pursuant to a bankruptcy termination clause will not be stayed, avoided or otherwise limited by operation of any provision of the Bankruptcy Code or by the order of any court in any proceeding under the Bankruptcy Code. Similarly, Section 560 provides, among other things, that the contractual right of any swap participant to cause the termination of a swap agreement pursuant to a bankruptcy termination clause or to offset or net out any termination values or payment amounts under or in connection with a swap agreement shall not be stayed, avoided or otherwise limited by operation of any provision of the Bankruptcy Code or by order of a court or administrative agency in any proceeding under the Bankruptcy Code. Section 362(b)(6) of the Bankruptcy Code authorizes the setoff of any mutual debts and claims arising from forward contracts and securities contracts between a debtor and a non-debtor, and 362(b)(17) of any mutual debts arising from one or more swap agreements between a debtor and a non-debtor. Finally, "swap agreement" is defined by Section 101(53B)(C) of the Bankruptcy Code to include any master agreement relating to derivative instruments of the nature identified in that section (which includes commodity derivatives).

The Company believes that the netting of debts and claims across the underlying master agreements and the transactions entered into pursuant to the master agreements, as provided for in the Netting Agreement, is entitled to the benefits of the provisions of the Bankruptcy Code summarized above although there can be no assurance in this regard. This conclusion is based not only on the language of the relevant statutory provisions, but also the policy underlying their adoption, which was to preserve the ability of counterparties to derivative contracts to immediately net and close out their contracts in the event of a bankruptcy. This is viewed as a beneficial way to mitigate systemic risk that could otherwise arise in a bankruptcy where the presence of the automatic stay, as well as the bankruptcy trustee's broad equitable powers with respect to executory contracts, would cast significant doubt upon the ongoing enforceability of derivative transactions. Separate and apart from these special protections provided by the Bankruptcy Code for forward contracts and swap agreements, the Netting Agreement and the netting provisions of the underlying master agreements are formal written agreements that would in any event be enforceable. The setoffs made by CES are often referred to as "triangular setoffs". A triangular setoff is one where A seeks to offset an obligation it owes to B against a debt that B owes to C. Here, a triangular setoff is one where CES seeks to set off an obligation it owes to ENA against a debt that EPMI owes to CES or, put another way, one where CES seeks to require the Enron entities to aggregate their debts and claims for setoff purposes. While the strict mutuality of Section 553 of the Bankruptcy Code is not present, if the parties all agree in a pre-petition contract that a setoff may be taken between A, B and C, then the agreement may be enforced in bankruptcy to the extent that it is enforceable under applicable nonbankruptcy law. This exception is limited, however, to cases where there is a formal pre-petition contract, such as the Netting Agreement.

In addition to the written Netting Agreement, for nearly a year prior to the bankruptcy filing by Enron and certain of its affiliates, CES and the Enron entities offset and netted debts and claims under all of the forward contracts and swap agreements among the parties pursuant to an oral agreement that was relied upon. It is established that the "formal contract" required to establish the right of setoff under the Bankruptcy Code need not be in writing, so long as there is sufficient evidence indicating a definite understanding or agreement between the debtor and the corporation seeking a setoff.

See Note 18 of the Notes to Consolidated Financial Statements for our accounts receivable (payable) balances as well as the fair value of our open contracts with ENA and EPMI at December 31, 2001. We had no net exposure at December 31, 2001, because of our netting arrangements with ENA and EPMI. In view of the foregoing, a reserve is not needed for our Enron positions, in the opinion of management.

Our treasury department includes a credit group focused on monitoring and managing counterparty risk. The credit group monitors the net exposure with each counterparty on a daily basis. The analysis is performed on a mark-to-market basis using the forward curves audited by our Risk Controls group. The net exposure is compared against a counterparty credit risk threshold which is determined based on the counterparty's credit ratings, evaluation of the financial statements and bond values. The credit department monitors these thresholds to determine the need for additional collateral or an adjustment to activity with the counterparty.

The effects of the Enron bankruptcy upon our business and upon the energy industry in general are difficult to predict. The outcome of the bankruptcy proceeding will not be known for some time, and thus we cannot be certain that our analysis of our rights and obligations with respect to Enron will prevail during that proceeding. It is also difficult to predict whether the demise of Enron will have ancillary effects on our market, including the regulatory environment in which we operate. Any such changes could affect our business plan, including our ability to engage in hedging, balancing or optimization transactions relating to our portfolio of assets.

Capital Resources

Our credit ratings have been downgraded and could be downgraded further. In December 2001, Moody's and Fitch downgraded our long-term debt credit rating and we remain on credit watch with negative implications at Moody's. In addition, in March 2002, Fitch downgraded our senior unsecured debt credit rating and Standard & Poor's downgraded our corporate credit rating and our senior unsecured debt credit rating. We cannot assure you that Moody's, Fitch and Standard & Poor's will not further downgrade our credit ratings in the future. If our credit rating is downgraded, we could be required to, among other things, pay additional interest under our credit agreements, or provide additional guarantees, collateral, letters of credit or cash for credit support obligations andit could increase our cost of capital, make our efforts to raise capital more difficult and have an adverse impact on us and our subsidiaries.

We have substantial indebtedness that we may be unable to service and that restricts our activities. We have substantial debt that we incurred to finance the acquisition and development of power generation facilities. As of December 31, 2001, our total consolidated indebtedness was $12.7 billion, our total consolidated assets were $21.3 billion and our stockholders' equity was $3.0 billion. Whether we will be able to meet our debt service obligations and repay our outstanding indebtedness will be dependent primarily upon the performance of our power generation facilities and of our oil and gas properties.

This high level of indebtedness has important consequences, including:

- limiting our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of our growth strategy, or other purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service the debt;
- increasing our vulnerability to general adverse economic and industry conditions; and
- limiting our ability to capitalize on business opportunities and to react to competitive pressures and adverse changes in government regulation.

The operating and financial restrictions and covenants in certain of our existing debt agreements limit or prohibit our ability to:

- incur indebtedness;
- make prepayments of indebtedness in whole or in part;
- pay dividends;
- make investments;
- engage in transactions with affiliates;
- create liens;
- sell assets; and
- acquire facilities or other businesses.

Also, if our management or ownership changes, the indentures governing certain of our senior notes may require us to make an offer to purchase those senior notes. We cannot assure that we will have the financial resources necessary to purchase those senior notes in this event.

We believe that our cash flow from operations, together with other available sources of funds, including borrowings under our existing borrowing arrangements, will be adequate to pay principal and interest on our senior notes and other debt and to enable us to comply with the terms of our indentures and other debt agreements. If we are unable to comply with the terms of our indentures and other debt agreements and fail to generate sufficient cash flow from operations in the future, we may be required to refinance all or a portion of our senior notes and other debt or to obtain additional financing. However, we may be unable to refinance or obtain additional financing because of our high levels of debt and the debt incurrence restrictions under our indentures and other debt agreements. If cash flow is insufficient and refinancing or additional financing is unavailable, we may be forced to default on our senior notes and other debt obligations. In the event of a default under the terms of any of our indebtedness, the debt holders may accelerate the maturity of our obligations, which could cause defaults under our other obligations.

Our ability to repay our debt depends upon the performance of our subsidiaries. Almost all of our operations are conducted through our subsidiaries and other affiliates. As a result, we depend almost entirely upon their earnings and cash flow to service our indebtedness, including our ability to pay the interest on and principal of our senior notes. The lease agreements of certain of our subsidiaries and other affiliates generally restrict their ability to pay dividends, make distributions, or otherwise transfer funds to us prior to the payment of other obligations, including operating expenses, lease payments and reserves.

Our subsidiaries and other affiliates are separate and distinct legal entities and have no obligation to pay any amounts due on our senior notes, and do not guarantee the payment of interest on or principal of these notes. The right of our senior note holders to receive any assets of any of our subsidiaries or other affiliates upon our liquidation or reorganization will be subordinated to the claims of any subsidiaries' or other affiliates' creditors (including trade creditors and holders of debt issued by our subsidiaries or affiliates). As of December 31, 2001, our subsidiaries had $3.4 billion of project financing. We may utilize project financing, when appropriate in the future, and this financing will be effectively senior to our senior notes.

While the indentures impose limitations on our ability and the ability of our subsidiaries to incur additional indebtedness, the indentures do not limit the amount of project financing that our subsidiaries may incur to finance the acquisition and development of new power generation facilities.

We may be unable to secure additional financing in the future. Each power generation facility that we acquire or develop will require substantial capital investment. Our ability to arrange financing and the cost of the financing are dependent upon numerous factors. These factors include:

- general economic and capital market conditions;
- conditions in energy markets;
- regulatory developments;
- credit availability from banks or other lenders for us and our industry peers, as well as the economy in general
- investor confidence in the industry and in us;
- the continued success of our current power generation facilities; and
- provisions of tax and securities laws that are conducive to raising capital.

Financing for new facilities may not be available to us on acceptable terms in the future. We have financed our existing power generation facilities using a variety of leveraged financing structures, consisting of senior unsecured indebtedness, construction financing, project financing, and lease obligations. Most of our construction costs during 2001 were financed through one of our two Calpine Construction Finance Company ("CCFC") non-recourse debt facilities (see Note 8 of the Notes to Consolidated Financial Statements). As of December 31, 2001, we had approximately $12.7 billion of total consolidated indebtedness, $3.4 billion of construction/project financing, $0.2 billion of capital lease obligations, $7.0 billion in senior notes, $0.9 billion in Zero Coupons, $1.1 billion in Convertible Senior Notes Due 2006, and $0.1 million of notes payable and borrowings under lines of credit. Each project financing and lease obligation is structured to be fully paid out of cash flow provided by the facility or facilities financed or leased. In the event of a default under a financing agreement which we do not cure, the lenders or lessors would generally have rights to the facility and any related assets. In the event of foreclosure after a default, we might not retain any interest in the facility. While we intend to utilize non-recourse or lease financing when appropriate, market conditions and other factors may prevent similar financing for future facilities. We do not believe the existence of non-recourse or lease financing will significantly affect our ability to continue to borrow funds in the future in order to finance new facilities. However, it is possible that we may be unable to obtain the financing required to develop our power generation facilities on terms satisfactory to us.

We have from time to time guaranteed certain obligations of our subsidiaries and other affiliates. Our lenders or lessors may also require us to guarantee the indebtedness for future facilities. Guarantees render our general corporate funds vulnerable in the event of a default by the facility or related subsidiary. Additionally, certain of our indentures may restrict our ability to guarantee future debt, which could adversely affect our ability to fund new facilities. Our indentures do not limit the ability of our subsidiaries to incur non-recourse or lease financing for investment in new facilities.

Operations

Revenue under some of our power sales agreements may be reduced significantly upon their expiration or termination. Some of the electricity we generate from our existing portfolio is sold under long-term power sales agreements that expire at various times. We also sell power under short to intermediate (1 to 5 year) contracts. When the terms of each of these various power sales agreements expire, it is possible that the price paid to us for the generation of electricity may be reduced significantly.

Derivatives trading activities can create volatility in earnings and may require significant cash collateral. During 2001, we recognized $134.8 million in mark-to-market gains on electric power and natural gas derivatives. Please see Impact of Recent Accounting Pronouncements for a detailed discussion of the accounting requirements under SFAS No. 133. We may enter into other transactions in future periods that require us to mark various derivatives to market through earnings. The nature of the transactions that we enter into in addition to volatility of natural gas and electric power prices will determine the volatility of earnings that we may experience.

As a result, in part, of the fallout from Enron's decline and declaration of bankruptcy on December 20, 2001, companies engaging in derivative trading activities have become sensitized to the inherent risks of such transactions. Consequently, companies, including us, are requiring cash collateral for certain derivative transactions in excess of what was previously required. As of December 31, 2001, we had $345.5 million in margin deposits with counterparties and $259.4 million of letters of credit related to our CES activities, compared to none at December 31, 2000. This change is due to new cash and letters of credit collateralization of derivative transactions in addition to our increased activity in such transactions. Future cash collateral requirements may increase based on the extent of our involvement in derivative activities and based on our credit ratings.

We may be unable to obtain an adequate supply of natural gas in the future. To date, our fuel acquisition strategy has included various combinations of our own gas reserves, gas prepayment contracts, short, medium and long-term supply contracts and gas hedging transactions. In our gas supply arrangements, we attempt to match the fuel cost with the fuel component included in the facility's power sales agreements in order to minimize a project's exposure to fuel price risk. In addition, the focus of our CES risk management organization is to manage the "spark spread" for our portfolio of generating plants, the spread between the cost of fuel and electricity revenues, and we actively enter into hedging transactions to lock in gas costs and spark spreads. We believe that there will be adequate supplies of natural gas available at reasonable prices for each of our facilities when current gas supply agreements expire. However, gas supplies may not be available for the full term of the facilities' power sales agreements, and gas prices may increase significantly. If gas is not available, or if gas prices increase above the level that can be recovered in electricity prices, there could be a negative impact on our results of operations.

Our power project development and acquisition activities may not be successful. The development of power generation facilities is subject to substantial risks. In connection with the development of a power generation facility, we must generally obtain:

- necessary power generation equipment;
- governmental permits and approvals;
- fuel supply and transportation agreements;
- sufficient equity capital and debt financing;
- electrical transmission agreements; and
- site agreements and construction contracts.

We may be unsuccessful in accomplishing any of these matters or in doing so on a timely basis. In addition, project development is subject to various environmental, engineering and construction risks relating to cost-overruns, delays and performance. Although we may attempt to minimize the financial risks in the development of a project by securing a favorable power sales agreement, obtaining all required governmental permits and approvals, and arranging adequate financing prior to the commencement of construction, the development of a power project may require us to expend significant sums for preliminary engineering, permitting and legal, and other expenses before we can determine whether a project is feasible, economically attractive or financeable. If we were unable to complete the development of a facility, we might not be able to recover our investment in the project. The process for obtaining initial environmental, siting and other governmental permits and approvals is complicated and lengthy, often taking more than one year, and is subject to significant uncertainties. We cannot assure that we will be successful in the development of power generation facilities in the future.

We have grown substantially in recent years as a result of acquisitions of interests in power generation facilities and steam fields. We believe that although the domestic power industry is undergoing consolidation and significant acquisition opportunities are available, we are likely to confront significant competition for acquisition opportunities. In addition, we may be unable to continue to identify attractive acquisition opportunities at favorable prices or, to the extent that any opportunities are identified, we may be unable to complete the acquisitions.

Our projects under construction may not commence operation as scheduled. The commencement of operation of a newly constructed power generation facility involves many risks, including:

- start-up problems;
- the breakdown or failure of equipment or processes; and
- performance below expected levels of output or efficiency.

New plants have no operating history and may employ recently developed and technologically complex equipment. Insurance is maintained to protect against certain risks, warranties are generally obtained for limited periods relating to the construction of each project and its equipment in varying degrees, and contractors and equipment suppliers are obligated to meet certain performance levels. The insurance, warranties or performance guarantees, however, may not be adequate to cover lost revenues or increased expenses. As a result, a project may be unable to fund principal and interest payments under its financing obligations and may operate at a loss. A default under such a financing obligation, unless cured, could result in losing our interest in a power generation facility.

In certain situations, power sales agreements entered into with a utility early in the development phase of a project may enable the utility to terminate the agreement, or to retain security posted as liquidated damages, if a project fails to achieve commercial operation or certain operating levels by specified dates or fails to make specified payments. In the event a termination right is exercised, the default provisions in a financing agreement may be triggered (rendering such debt immediately due and payable). As a result, the project may be rendered insolvent and we may lose our interest in the project. In recent years we have relied less and less on traditional project financing, so the risk of a financing agreement default linked to a default under a power sales agreement comes into play infrequently.

Our power generation facilities may not operate as planned. Upon completion of our projects currently under construction, we will operate 82 of the 86 power plants in which we will have an interest. The continued operation of power generation facilities involves many risks, including the breakdown or failure of power generation equipment, transmission lines, pipelines or other equipment or processes, and performance below expected levels of output or efficiency. Although from time to time our power generation facilities have experienced equipment breakdowns or failures, these breakdowns or failures have not had a significant effect on the operation of the facilities or on our results of operations. For calendar year 2001, our gas-fired and geothermal power generation facilities have operated at an average availability of approximately 93% and 92%, respectively. Although our facilities contain various redundancies and back-up mechanisms, a breakdown or failure may prevent the affected facility from performing under applicable power sales agreements. In addition, although insurance is maintained to protect against operating risks, the proceeds of insurance may not be adequate to cover lost revenues or increased expenses. As a result, we could be unable to service principal and interest payments under our financing obligations which could result in losing our interest in the power generation facility.

We cannot assure that our estimates of oil and gas reserves are accurate. Estimates of proved oil and gas reserves and the future net cash flows attributable to those reserves are prepared by independent petroleum and geological engineers. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and cash flows attributable to such reserves, including factors beyond our control and that of our engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and gas prices and expenditures for future development and exploitation activities, and of engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development and exploration activities and prices of oil and gas. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions set forth herein. In addition, different reserve engineers may make different estimates of reserves and cash flows based on the same available data.

Our geothermal energy reserves may be inadequate for our operations. The development and operation of geothermal energy resources are subject to substantial risks and uncertainties similar to those experienced in the development of oil and gas resources. The successful exploitation of a geothermal energy resource ultimately depends upon:

- the heat content of the extractable fluids;
- the geology of the reservoir;
- the total amount of recoverable reserves;
- operating expenses relating to the extraction of fluids;
- price levels relating to the extraction of fluids or power generated; and
- capital expenditure requirements relating primarily to the drilling of new wells.

In connection with each geothermal power plant, we estimate the productivity of the geothermal resource and the expected decline in productivity. The productivity of a geothermal resource may decline more than anticipated, resulting in insufficient reserves being available for sustained generation of the electrical power capacity desired. An incorrect estimate by us or an unexpected decline in productivity could lower our results of operations.

Geothermal reservoirs are highly complex. As a result, there exist numerous uncertainties in determining the extent of the reservoirs and the quantity and productivity of the steam reserves. Reservoir engineering is an inexact process of estimating underground accumulations of steam or fluids that cannot be measured in any precise way, and depends significantly on the quantity and accuracy of available data. As a result, the estimates of other reservoir specialists may differ materially from ours. Estimates of reserves are generally revised over time on the basis of the results of drilling, testing and production that occur after the original estimate was prepared. While we have extensive experience in the operation and development of geothermal energy resources and in preparing such estimates, we cannot assure that we will be able to successfully manage the development and operation of our geothermal reservoirs or that we will accurately estimate the quantity or productivity of our steam reserves.

California Power Market

The current issues in the California power market could adversely affect our performance. The deregulation of the California power market has produced significant unanticipated results in the past two years. The deregulation froze the rates that utilities can charge their retail and business customers in California, until rate increases were approved by the California Public Utilities Commission ("CPUC") in 2001, and prohibited the utilities from buying power on a forward basis, while wholesale power prices were not subjected to limits.

A series of factors reduced the supply of power to California from mid 2000 through the spring of 2001, which resulted in wholesale power prices for that period that were significantly higher than historical levels. Several factors contributed to this increase. These included:

- significantly increased volatility in prices and supplies of natural gas;
- an unusually dry fall and winter in the Pacific Northwest during 2000, which reduced the amount of available hydroelectric power from that region (typically, California imports a portion of its power from this source);
- the large number of power generating facilities in California nearing the end of their useful lives, resulting in increased downtime (either for repairs or because they had exhausted their air pollution credits and replacement credits had become too costly to acquire on the secondary market); and
- continued obstacles to new power plant construction in California, which deprived the market of new power sources that could have, in part, ameliorated the adverse effects of the foregoing factors.

During the period of higher wholesale prices, there was significant under-recovery of costs by two of the major California utilities. As a consequence, these two utilities defaulted under a variety of contractual obligations, including payment obligations to power generators. PG&E defaulted on payment obligations to the Company under its long-term QF contracts, which are subject to federal regulation under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). The PG&E QF contracts are in place at eleven of our facilities and represent nearly 600 megawatts of electricity for Northern California customers.

Commencing in the second half of 2001, the supply/demand imbalance for electric power has been substantially reduced in the short term, resulting in significantly lower power prices than were seen in the earlier part of the year. These reductions may be attributed to milder than expected summer and fall in California and the western United States, a reduction in the demand for power as a result of the economic downturn in the region and greater consumer conservation, changes in the power market, including a greater portion of power sold on a long-term, forward basis, than on a short-term spot basis, reduction in the natural gas prices, and the introduction of new supplies of power.

On April 6, 2001, PG&E filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. As of April 6, 2001, we had recorded approximately $265.6 million in accounts receivable with PG&E under our QF contracts, plus $68.7 million in notes receivable not yet due and payable. On July 6, 2001, we announced that we had entered into a binding agreement with PG&E to modify all of our QF contracts with PG&E and that, based upon such modification, PG&E had agreed to assume all of the QF contracts. Under the terms of this agreement, we continue to receive our contractual capacity payments under the QF contracts, plus a five-year fixed energy price component that averages 5.37 cents per kilowatt-hour in lieu of the short run avoided cost. In addition, all past due receivables under the QF contracts were elevated to administrative priority status in the PG&E bankruptcy proceeding and are to be paid to the Company, with interest, upon the effective date of a confirmed plan of reorganization. Administrative claims enjoy priority over payments made to the general unsecured creditors in bankruptcy. The bankruptcy court approved the agreement on July 12, 2001. On December 6, 2001, Calpine and PG&E executed a supplemental agreement to the July 6, 2001, agreement whereby PG&E agreed to commence paying Calpine all pre-petition receivables due under the QF contracts with interest at a rate of 5% per annum. The payments are to be made in twelve monthly installments with the first payment of principal made on December 31, 2001, including all accrued interest from the initial default dates, and the last payment of principal and interest on November 30, 2002. In the event that the effective date of a confirmed plan of reorganization occurs sooner than the payment dates, PG&E is required to make all payments owed to Calpine, including interest thereon accruing at 5%, as of such effective date. However, under the terms of the supplemental agreement, PG&E's obligation to make such payments is separate from and not dependent upon the confirmation of a plan of reorganization. The bankruptcy court approved the supplemental agreement on December 21, 2001. There has been no final plan of reorganization approved by the bankruptcy court. After receiving the first of twelve payments, including accrued interest through December 31, 2001, the Company sold the remaining receivable on December 31, 2001, for 96.125% of its face value.

CPUC Proceeding Regarding QF Contract Pricing for Past Periods. Our QF contracts with PG&E provide that the CPUC has the authority to determine the appropriate utility "avoided cost" to be used to set energy payments for certain QF contracts by determining the short run avoided cost ("SRAC") energy price formula. In mid 2000, our QF facilities elected the option set forth in Section 390 of the California Public Utility Code, which provides QFs the right to elect to receive energy payments based on the California Power Exchange ("PX") market clearing price instead of the price determined by SRAC. Having elected such option, we were paid based upon the PX zonal day ahead clearing price ("PX Price") from summer 2000 until January 19, 2001, when the PX ceased operating a day ahead market. The CPUC has conducted proceedings (R.99-11-022) to determine whether the PX Price was the appropriate price for the energy component upon which to base payments to QFs which had elected the PX-based pricing option. The CPUC at one point issued a proposed decision to the effect that the PX Price was the appropriate price for energy payments under the California Public Utility Code but tabled it, and a final decision has not been issued to date. Therefore, it is possible that the CPUC could order a payment adjustment based on a different energy price determination. We believe that the PX Price was the appropriate price for energy payments but there can be no assurance that this will be the outcome of the CPUC proceedings.

Current California QF Contract Pricing. When the PX ceased operation on January 19, 2001, the CPUC ordered that the QFs that had previously switched to the PX Price be switched back to the applicable SRAC energy price formula. On June 14, 2001, however, the CPUC issued an order (Decision 01-06-015) (the "June 2001 Decision") that authorized the California utilities, including PG&E, to amend QF contracts to elect a fixed energy price component that averages 5.37 cents per kilowatt-hour for a five-year term under those contracts in lieu of using the SRAC energy price formula. By this order, the CPUC authorized the QF contract energy price amendments without further CPUC concurrence. As part of the agreement we entered into with PG&E pursuant to which PG&E, in bankruptcy, agreed to assume its QF contracts with us, PG&E agreed with us to amend these contracts to adopt the fixed price component that averages 5.37 cents pursuant to the June 2001 Decision. This election became effective as of July 16, 2001. As a result of the June 2001 Decision and our agreement with PG&E to amend the QF contracts to adopt the fixed price energy component, the energy price component in our QF contracts is now fixed for five years. As of July 1, 2006, the energy payment under the QF contracts with PG&E will be determined by the CPUC in accordance with its determination of the SRAC energy price formula.

California Long-Term Supply Contracts. California has adopted legislation permitting it to issue long-term revenue bonds to provide funding for wholesale purchases of power. The bonds will be repaid with the proceeds of payments by retail customers over time. The California Department of Water Resources ("DWR") sought bids for long-term power supply contracts in a publicly announced auction. Calpine successfully bid in that auction and signed several long-term power supply contracts with DWR.

On February 7, 2001, we announced the signing of a 10-year, $4.6 billion fixed price contract with DWR to provide electricity to the State of California. We committed to sell up to 1,000 megawatts of electricity, with initial deliveries of 200 megawatts starting October 1, 2001, which increases to 1,000 megawatts by January 1, 2004. The electricity will be sold directly to DWR on a 24 hours-a-day, 7 days-a-week basis.

On February 28, 2001, we announced the signing of two long-term power sales contracts with DWR. Under the terms of the first contract, a 10-year, $5.2 billion fixed price contract, we committed to sell up to 1,000 megawatts of generation. Initial deliveries began July 1, 2001, with 200 megawatts and increase to 1,000 megawatts by as early as July 2002. Under the terms of the second contract, a 20-year contract totaling up to $3.1 billion, we will supply DWR with up to 495 megawatts of peaking generation, beginning with 90 megawatts in August 2001 and increasing up to 495 megawatts as early as August 2002.

On June 11, 2001, we announced the signing of a three-year peaking contract to supply DWR with up to 225 megawatts of peaking generation beginning in the summer of 2002 through April 30, 2005, from the Los Esteros Critical Energy Facility currently under development in San Jose, California. In the event that the Los Esteros Critical Energy Facility has not achieved commercial operation by October 1, 2002, DWR would have the right to terminate the contract.

On December 11, 2001, Calpine announced that it was meeting with officials from the State of California at their request to discuss whether, and if so how, the long-term contracts with DWR could be modified. No definitive modifications have been agreed to and the discussions have been ongoing.

However, we currently have a dispute with DWR concerning payment of the capacity payment on the 495-megawatt peaking contract dated February 28, 2001. The contract provides that CES may earn a capacity payment by committing to supply electricity to DWR from a source other than the peaker units designated in the contract either through substitution of those designated units or by providing replacement energy. DWR has made certain assertions challenging CES' right to substitute units or provide replacement energy and has withheld capacity payments in the amount of $9.5 million since December 2001. The resolution of this dispute is part of the ongoing discussions regarding modifications to the contracts.

On February 25, 2002, both the CPUC and the California Electric Oversight Board filed complaints under Section 206 of the Federal Power Act with the FERC (EL02-60-000 and EL02-62-000, respectively) alleging that the prices and terms of the long-term contracts with DWR are unjust and unreasonable and counter to the public interest. Calpine is a respondent and the four long-term contracts entered into by Calpine are subject to the complaint. The FERC has noticed this proceeding and responsive filings are due from the respondents on or before March 22, 2002. Calpine believes that the complaints are without merit and intends to defend its position vigorously.

On March 6, 2002, in accordance with the state legislation that authorized DWR to enter into the long-term power contracts, the CPUC issued a Rate Agreement, which dedicates a portion of the retail rate paid by electricity customers of the California investor-owned utilities to a fund to pay bondholders of bonds to be issued by DWR and to a fund to pay electricity suppliers such as Calpine. The proceeds from those bonds will be used in part to fund the Electric Power Fund established by the state legislation authorizing DWR to enter into long-term power contracts with the power suppliers whose recourse in the event of a default by DWR is to the Electric Power Fund. Proceeds from the bonds will also be used to repay the state of California General Fund. The bonds have not been issued, but representatives of the State have indicated that the bonds should be issued in the near future.

FERC Investigation into California Wholesale Markets — In August 2000, FERC initiated an investigation of the California power markets. In November 2000 FERC found that the California power market structure and market rules were seriously flawed, and that these flaws, together with short supply relative to demand, resulted in unusually high energy prices. FERC proposed specific remedies to the identified market flaws that included the potential refund of rates charged for service determined by FERC not to be just and reasonable.

Through a series of orders most recently culminating in its order of December 19, 2001, FERC has prescribed a methodology for determining potential refunds in the California wholesale electric markets. The key elements of this methodology are:

- the refund period runs from October 2, 2000, through June 19, 2001.
- the only sales subject to price mitigation and potential refund are spot market transactions (sales entered into 24 hours or less in advance of the delivery of power).
- the methodology for determining refunds is based upon the costs associated with the least efficient generating unit needed to meet system requirements during any relevant pricing interval.
- any refunds calculated under this methodology are to be offset by amounts owed to the seller from various entities purchasing power in California.
- actual application of the methodology and calculations of any refunds remain subject to ongoing proceedings before the FERC which are scheduled to conclude during the latter half of 2002.

The scope of the ongoing FERC investigation is limited to spot market sales made to the ISO and PX during the October 2, 2000, to June 19, 2001, time period, and so Calpine's forward long-term contracts (including its QF contracts) are not subject to this investigation. Due to the ongoing nature of this investigation and ambiguities concerning how the refund methodology is to be applied, it is not possible at this time to predict the amount of any potential refunds that Calpine ultimately may be required to pay. However, based on the information available at this time, we do not believe that the proceeding will result in a material adverse effect on our financial conditions or results of operations. It also should be noted that all of FERC orders issued in these proceedings to date are subject to judicial review sought by various parties. The outcome of these judicial proceedings cannot be determined at this time.

On June 19, 2001, FERC ordered price mitigation in 11 states in the western United States in an attempt to reduce the dependence of the California market on spot markets in favor of longer-term committed energy supplies. The order provides for price mitigation in the spot market throughout the 11 state western region during "reserve deficiency hours," which is when operating reserves in California fall below seven percent. This price will be a single market clearing price based upon the marginal operating cost of the last unit dispatched by the California ISO. In addition, FERC implemented price mitigation in non-reserve deficiency hours, which will be set at 85% of the market clearing price during the last reserve deficiency period. These price mitigation procedures went into effect on June 20, 2001, and will remain in effect until September 30, 2002.

The retention by FERC of a market-based, rather than a cost-of-service-based, rate structure will enable us to continue to realize benefits from our efficient, modern power plants. We believe that Calpine's marginal costs will continue to be below any price cap imposed by FERC, whether during reserve deficiency hours or at other times. Therefore, we believe that FERC's mitigation plan will not have a material adverse effect on Calpine's financial condition or results of operations.

FERC also ordered all sellers and buyers in wholesale power markets administered by the California ISO, as well as representatives of the State of California, to participate in a settlement conference before a FERC administrative law judge. The settlement discussions were intended to resolve all issues that remain outstanding to resolve past accounts, including sellers' claims for unpaid invoices, and buyers' claims for refunds of alleged overcharges, for past periods. The settlement discussions began on June 25, 2001, and ended on July 9, 2001. The Chief Administrative Law Judge issued his report and recommendations to FERC on July 12, 2001. On July 25, 2001, FERC ordered an expedited fact-finding hearing to calculate refunds for spot market transactions in California. The hearing has been delayed pending the submission by the California ISO and the PX of data for the purpose of developing the factual basis needed to implement the refund methodology and order refunds, and at this time it is not possible to determine when the proceeding will conclude. While it is not possible to predict the amount of any refunds until the hearings take place, based upon the information available at this time, we do not believe that this proceeding will result in a material adverse effect on the Company's financial condition or results of operations.

On February 13, 2002, FERC initiated an investigation of potential manipulation of electric and natural gas prices in the western United States. This investigation was initiated as a result of allegations that Enron Corp. through its affiliates used its market position to distort electric and natural gas markets in the West. The scope of the investigation is to consider whether as a result of any manipulation in the short-term markets for electric energy or natural gas or other undue influence on the wholesale markets by any party since January 1, 2000, the rates of the long-term contracts subsequently entered into in the West are potentially unjust and unreasonable. FERC has stated that it may use the information gathered in connection with the investigation to determine how to proceed on any existing or future complaint brought under Section 206 of the Federal Power Act involving long-term power contracts entered into in the West since January 1, 2000, or to initiate a Federal Power Act Section 206 or Natural Gas Act Section 5 proceeding on its own initiative.

Government Regulation

We are subject to complex government regulation which could adversely affect our operations. Our activities are subject to complex and stringent energy, environmental and other governmental laws and regulations. The construction and operation of power generation facilities require numerous permits, approvals and certificates from appropriate federal, state and local governmental agencies, as well as compliance with environmental protection legislation and other regulations. While we believe that we have obtained the requisite approvals for our existing operations and that our business is operated in accordance with applicable laws, we remain subject to a varied and complex body of laws and regulations that both public officials and private individuals may seek to enforce. Existing laws and regulations may be revised or reinterpreted, or new laws and regulations may become applicable to us that may have a negative effect on our business and results of operations. We may be unable to obtain all necessary licenses, permits, approvals and certificates for proposed projects, and completed facilities may not comply with all applicable permit conditions, statutes or regulations. In addition, regulatory compliance for the construction of new facilities is a costly and time-consuming process. Intricate and changing environmental and other regulatory requirements may necessitate substantial expenditures to obtain permits. If a project is unable to function as planned due to changing requirements or local opposition, it may create expensive delays or significant loss of value in a project.

Our operations are potentially subject to the provisions of various energy laws and regulations, including PURPA, the Public Utility Holding Company Act of 1935, as amended, ("PUHCA"), and state and local regulations. PUHCA provides for the extensive regulation of public utility holding companies and their subsidiaries. PURPA provides QFs (as defined under PURPA) and owners of QFs exemptions from certain federal and state regulations, including rate and financial regulations.

Under present federal law, we are not subject to regulation as a holding company under PUHCA, and will not be subject to such regulation as long as the plants in which we have an interest (1) qualify as QFs, (2) are subject to another exemption or waiver or (3) qualify as an Exempt Wholesale Generator ("EWG") under the Energy Policy Act of 1992. In order to be a QF, a facility must be not more than 50% owned by one or more electric utility companies or electric utility holding companies. In addition, a QF that is a cogeneration facility, such as the plants in which we currently have interests, must produce electricity as well as thermal energy for use in an industrial or commercial process in specified minimum proportions. The QF also must meet certain minimum energy efficiency standards. Generally, any geothermal power facility which produces up to 80 megawatts of electricity and meets PURPA ownership requirements is considered a QF.

If any of the plants in which we have an interest lose their QF status or if amendments to PURPA are enacted that substantially reduce the benefits currently afforded QFs, we could become a public utility holding company, which could subject us to significant federal, state and local regulation, including rate regulation. If we become a holding company, which could be deemed to occur prospectively or retroactively to the date that any of our plants loses its QF status, all our other power plants could lose QF status because, under FERC regulations, a QF cannot be owned by an electric utility or electric utility holding company. In addition, a loss of QF status could, depending on the particular power purchase agreement, allow the power purchaser to cease taking and paying for electricity or to seek refunds of past amounts paid and thus could cause the loss of some or all contract revenues or otherwise impair the value of a project. If a power purchaser were to cease taking and paying for electricity or seek to obtain refunds of past amounts paid, there can be no assurance that the costs incurred in connection with the project could be recovered through sales to other purchasers. Such events could adversely affect our ability to service our indebtedness, including our senior notes. See "Item 1 — Business — Government Regulation — Federal Energy Regulation — Federal Power Act Regulation."

Currently, Congress is considering proposed legislation that would repeal PUHCA and amend PURPA by limiting its mandatory purchase obligation to existing contracts. In light of the circumstances in California, the Pacific Gas and Electric Company bankruptcy and the Enron Corp. bankruptcy, among other events in 2001, there are a number of federal legislative and regulatory initiatives that could result in changes in how the energy markets are regulated. We do not know whether this legislation or regulatory initiatives will be adopted or, if adopted, what form they may take. We cannot provide assurance that any legislation or regulation ultimately adopted would not adversely affect our existing domestic projects.

In addition, many states are implementing or considering regulatory initiatives designed to increase competition in the domestic power generation industry and increase access to electric utilities' transmission and distribution systems for independent power producers and electricity consumers. However, in light of the circumstances in the California power markets and the bankruptcies of both PG&E and Enron, the pace and direction of further deregulation at the state level in many jurisdictions is uncertain. See "Item 1 — Business — Recent Developments — California Power Market."

Other Risk Factors

We depend on our senior management. Our success is largely dependent on the skills, experience and efforts of our senior management. The loss of the services of one or more members of our senior management could have a negative effect on our business, financial results and future growth.

Seismic disturbances could damage our projects. Areas where we operate and are developing many of our geothermal and gas-fired projects are subject to frequent low-level seismic disturbances. More significant seismic disturbances are possible. Our existing power generation facilities are built to withstand relatively significant levels of seismic disturbances, and we believe we maintain adequate insurance protection. However, earthquake, property damage or business interruption insurance may be inadequate to cover all potential losses sustained in the event of serious seismic disturbances. Additionally, insurance may not continue to be available to us on commercially reasonable terms.

Our results are subject to quarterly and seasonal fluctuations. Our quarterly operating results have fluctuated in the past and may continue to do so in the future as a result of a number of factors, including:

- the timing and size of acquisitions;
- the completion of development projects;
- variations in levels of production; and
- seasonal variations in energy prices.

Additionally, because we receive the majority of capacity payments under some of our power sales agreements during the months of May through October, our revenues and results of operations are, to some extent, seasonal.

The price of our common stock is volatile. The market price for our common stock has been volatile in the past, and several factors could cause the price to fluctuate substantially in the future. These factors include:

- announcements of developments related to our business;
- fluctuations in our results of operations;
- our debt to equity ratios and other leverage ratios;
- effect of significant events relating to the energy sector in general;
- sales of substantial amounts of our securities into the marketplace;

- general conditions in our industry, the power markets in which we participate, or the worldwide economy;
- an outbreak of war or hostilities;
- a shortfall in revenues or earnings compared to securities analysts' expectations;
- changes in analysts' recommendations or projections; and
- announcements of new acquisitions or development projects by us.

The market price of our common stock may fluctuate significantly in the future, and these fluctuations may be unrelated to our performance. General market price declines or market volatility in the future could adversely affect the price of our common stock, and the current market price may not be indicative of future market prices.

Financial and Commodity Market Risks

Short-term investments — As of December 31, 2001, we had short-term investments of $1.0 billion. These short-term investments consist of highly liquid investments with maturities of less than three months. We have the ability to hold these investments to maturity, and as a result, we would not expect the value of these investments to be affected to any significant degree by the effect of a sudden change in market interest rates.

Interest rate swaps and cross currency swaps — From time to time, we use interest rate swap and cross currency swap agreements to mitigate our exposure to interest rate and currency fluctuations associated with certain of our debt instruments. We do not use interest rate swap and currency swap agreements for speculative or trading purposes. In regards to foreign currency denominated senior notes, the swap notional amounts equal the amount of the related principal debt. The following tables summarize the fair market values of our existing interest rate swap and currency swap agreements as of December 31, 2001 (dollars in thousands):

Maturity Date	Notional Principal Amount	Weighted Average Interest Rate (Pay)	Weighted Average Interest Rate (Receive)	Fair Market Value
2009	$ 14,862	6.9%	3-month US LIBOR	$ (1,182)
2011	53,126	6.9%	3-month US LIBOR	(4,235)
2012	118,692	6.5%	3-month US LIBOR	(7,723)
2014	67,929	6.7%	3-month US LIBOR	(5,217)
2015	22,500	7.0%	3-month US LIBOR	(2,227)
2018	17,500	7.0%	3-month US LIBOR	(1,875)
Total	$294,609	6.7%	3-month US LIBOR	$(22,459)

Maturity Date	Notional Principal (Pay/Receive)	Fixed Currency Exchange (Pay/Receive)	Frequency of Currency Exchange	Fair Market Value
2007	US$127,763/C$200,000	US$5,545/C$8,750	Semi-annually	$(1,479)
2008	£109,550/€175,000	£5,152/€7,328	Semi-annually	(8,012)

Certain Trading Activities

Energy price fluctuations — As an independent power producer primarily focused on generation of electricity using gas-fired turbines, our natural physical commodity position is "short" (we require) gas and "long" (we own) power capacity. To manage forward exposure to price fluctuation in these and (to a lesser extent) other commodities, we enter into derivative commodity instruments. All transactions are subject to our risk management policy which prohibits positions that exceed production capacity and fuel requirements on a total portfolio basis. Any hedging, balancing, or optimization activities that we engage in are directly related to our asset-based business model of owning and operating gas-fired electric power plants. We hedge exposures that arise from the ownership and operation of power plants and related sales of electricity and purchases of natural gas, and we utilize derivatives to optimize the returns we are able to achieve from these assets for our shareholders. This model is markedly different from that of companies that engage in significant commodity trading operations that are unrelated to underlying physical assets. Derivative commodity instruments are accounted for under the requirements of SFAS No. 133.

The change in fair value of outstanding commodity derivative instruments from January 1, 2001 through December 31, 2001 is summarized in the table below (in thousands):

Fair value of contracts outstanding at January 1, 2001	$ 87,413
(Gains) losses realized or otherwise settled during the period(1)	(161,627)
Changes in fair value attributable to changes in valuation techniques and assumptions	—
Other changes in fair value	(13,909)
Fair value of contracts outstanding at December 31, 2001(2)	$ (88,123)

(1) Realized cash flow hedges of $132.5 million reported in footnote 19 of the financial statements and $29.1 million realized gain on trading activity reported in the performance metrics section of the management discussion and analysis, both included in this filing.

(2) Net liabilities reported in Note 19 of the Notes to Consolidated Financial Statements included in this filing.

The fair value of outstanding derivative commodity instruments at December 31, 2001, based on price source and the period during which the instruments will mature (i.e., be realized) are summarized in the table below (in thousands):

Fair Value Source	2002	2003-2004	2005-2006	After 2006	Total
Prices actively quoted	$(176,237)	$(252,128)	$ —	$ —	$(428,365)
Prices provided by other external sources	223,597	51,923	22,241	—	297,761
Prices based on models and other valuation methods	104,859	4,726	(67,068)	(36)	42,481
Total fair value	$ 152,219	$(195,479)	$(44,827)	$(36)	$ (88,123)

The Company's traders maintain fair value price information derived from various sources in the Company's trading and risk management systems. The propriety of that information is validated by the Company's Risk Control function. Prices actively quoted include validation with prices sourced from commodities exchanges (e.g., New York Mercantile Exchange). Prices provided by other external sources include quotes from commodity brokers and electronic trading platforms. Prices based on models and other valuation methods are validated using quantitative methods. Validation methods have been independently reviewed for propriety.

The counterparty credit quality associated with the fair value of outstanding derivative commodity instruments at December 31, 2001, and the period during which the instruments will mature (i.e., be realized) are summarized in the table below (in thousands):

Credit Quality (based on March 15, 2002 ratings)	2002	2003-2004	2005-2006	After 2006	Total
Investment grade	$ 22,229	$ 11,197	$ 12,515	$(36)	$ 45,905
Noninvestment grade	125,287	(212,077)	(57,342)	—	(144,132)
No external ratings	4,703	5,401	—	—	10,104
Total fair value	$ 152,219	$(195,479)	$(44,827)	$(36)	$ (88,123)

The fair value of outstanding derivative commodity instruments and the change in fair value that would be expected from a ten percent adverse price change are shown in the table below (in thousands):

	Fair Value	Change In Fair Value From 10% Adverse Price Change
At December 31, 2001:		
Crude oil	$ 9,573	$ (9,364)
Electricity	526,849	(73,937)
Natural gas	(624,545)	(134,289)
Total	$ (88,123)	$(217,590)

Derivative commodity instruments included in the table are those included in Note 19 of the Notes to Consolidated Financial Statements. The fair values of derivative commodity instruments included in the table are calculated based on discounted cash flows derived using forward price curves. During 2001, significant electricity price volatility occurred particularly in the western United States. The positive fair value of electricity derivative commodity instruments includes the effect of decreased power prices versus our derivative forward commitments. Conversely, the negative fair value of the natural gas derivatives reflects the general decline in gas prices. Derivative commodity instruments offset physical positions exposed to the cash market. None of the offsetting physical positions are included in the above table.

Price changes were calculated by assuming an across-the-board ten percent adverse price change regardless of term or historical relationship between the contract price of an instrument and the underlying commodity price. It may be unlikely that an across-the-board ten percent adverse price change would occur. In the event of an actual change in prices that averages ten percent, the fair value of Calpine's derivative portfolio would typically change by more than ten percent for earlier forward months and less than ten percent for later forward months because of the higher volatilities in the near term and the effects of discounting expected future cash flows.

The primary factors affecting the fair value of the Company's derivatives at any point in time are (1) the volume of open derivative positions (MMBbls, MMBtu, and Mwh), and (2) changing commodity market prices, principally for crude oil, electricity, and natural gas. The total volume of open gas derivative positions increased 899% in 2001 while the total volume of open power derivative positions increased 1,251% for the same period. In that prices for electricity and natural gas are among the most volatile of all commodity prices, there may be material changes in the fair value of the Company's derivatives over time, driven both by price volatility and the increases in volume of open derivative transactions. Under SFAS No. 133, the change since the last balance sheet date in the total value of the derivatives (both assets and liabilities) is reflected either in OCI, net of tax, or in the statement of operations as an item (gain or loss) of current earnings. As of December 31, 2001, the majority of the balance in accumulated OCI represented the unrealized net loss associated with commodity cash flow hedging transactions. As noted above, there is a substantial amount of volatility inherent in accounting for the fair value of these derivatives, and the Company's results during 2001 have reflected this. See Note 19 for additional information on derivative activity.

Critical Accounting Policies

Our financial statements reflect the selection and application of accounting policies which require management to make significant estimates and assumptions. We believe that the following are some of the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

Revenue Recognition/Fair Value Accounting — We derive a significant portion of our revenues from sales of physical power in the wholesale electricity market as well as from energy marketing and risk management activities. With respect to physical power sales, we consider revenue earned upon output, delivery or satisfaction of specific targets, all as specified by contractual terms. Revenues under long-term power sales arrangements are recognized on an accrual basis. In addition, we account for certain transactions and activities at fair value. The majority of these represent energy trading and marketing contracts which are marked-to-market under EITF No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" and derivatives which are carried at fair value in accordance with SFAS No. 133. For energy marketing and risk management activities, we follow either the mark-to-market method of accounting as prescribed by SFAS No. 133 or EITF No. 98-10. Under the mark-to-market method of accounting, financial instruments and contractual commitments are recorded at fair value upon contract execution. The initial recognition of value as well as subsequent changes in value affect reported earnings in the respective period. The values of those instruments that remain open at the balance sheet date represent unrealized gains or losses and are presented as derivative risk management assets and liabilities in the consolidated balance sheets. Please see "Impact of Recent Accounting Pronouncements" for further discussion of our adoption and application of SFAS No. 133.

The determination of fair value of energy marketing and risk management contracts as well as derivatives can be complex and relies on judgments concerning future prices and liquidity, among other things. Generally speaking the longer the term of the contract, the more difficult it is to estimate accurate fair value.

We recognize our revenue and related expense from energy marketing and risk management activities in accordance with EITF No. 99-19 "Reporting Revenue Gross as a Principal versus Net as an Agent." This requires us to report a substantial amount of our hedging, balancing, optimization and trading activity on a gross basis.

Income Taxes — SFAS No. 109, "Accounting for Income Taxes," requires the asset and liability approach for financial accounting and reporting for deferred income taxes. We use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant income tax temporary differences (See Note 15 to the Notes to Consolidated Financial Statements for additional details).

As part of the process of preparing our consolidated financial statements we are required to estimate our income taxes in each of the jurisdictions in which we operate. This process involves us estimating our actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within our consolidated balance sheet.

We must then assess the likelihood that our deferred tax assets will be recovered from future taxable income and to the extent we believe that recovery is not likely, we must establish a valuation allowance. Significant management judgment is required in determining our provision for income taxes, our deferred tax assets and liabilities and any valuation allowance recorded against our net deferred tax assets. To the extent we establish a valuation allowance or increase this allowance in a period, we must include an expense within the tax provisions in the statement of income.

We have recorded on our consolidated balance sheet deferred tax assets of $140.0 million at December 31, 2001 which includes amounts relating to loss carryforwards. We believe there will be sufficient capital gains and taxable income in the future allowing us to utilize these loss carryforwards in the tax jurisdictions where they exist.

We have also recorded deferred taxes on undistributed earnings of foreign subsidiaries if those earnings are to be repatriated to the United States. Deferred tax assets have been recorded for foreign tax credits that we expect to utilize in the future as we generate taxable income from our foreign subsidiaries. Deferred taxes have not been accrued if those earnings have been, or are intended to be, indefinitely reinvested.

Long-Lived Assets, Including Intangibles — We evaluate long-lived assets, such as property, plant and equipment, equity method investments, patents, and specifically identifiable intangibles, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Factors which could trigger an impairment include significant underperformance relative to historical or projected future operating results; significant changes in the manner of our use of the acquired assets or the strategy for our overall business; and significant negative industry or economic trends.

The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. If an impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the fair value of the assets and recording a loss if the fair value was less than the book value. For equity method investments and assets identified as held for sale, the book value is compared to the estimated fair value to determine if an impairment loss is required. For equity method investments, we would record a loss when the decline in value is other than temporary.

Our assessment regarding the existence of impairment factors is based on market conditions, operational performance and legal factors of our businesses. Our review of factors present and the resulting appropriate carrying value of our goodwill, intangibles, and other long-lived assets are subject to judgments and estimates that management is required to make. Future events could cause us to conclude that impairment indicators exist and that our goodwill, intangibles, and other long-lived assets might be impaired.

Capitalized Interest — The Company capitalizes interest on capital invested in projects during the advanced stages of development and the construction period in accordance with SFAS No. 34, "Capitalization of Interest Cost," as amended by SFAS No. 58, "Capitalization of Interest Cost in Financial Statements That Include Investments Accounted for by the Equity Method (an Amendment of FASB Statement No. 34)." The Company's qualifying assets include construction in progress, certain oil and gas properties under development, construction costs related to unconsolidated investments in power projects under construction, and advanced stage development costs. Upon commencement of plant operation, capitalized interest, as a component of the total cost of the plant, is amortized over the estimated useful life of the plant. The increase in the amount of interest capitalized during the year ended December 31, 2001, reflects the significant increase in the Company's power plant construction program.

In accordance with SFAS No. 34, the Company determines which debt instruments best represent a reasonable measure of the cost of financing construction assets in terms of interest cost incurred that otherwise could have been avoided. These debt instruments and associated interest cost are included in the calculation of the weighted average interest rate used for capitalizing interest on general funds. The primary debt instruments included in the rate calculation for 2000 and 2001 are the Senior Notes and the $400 million corporate revolver.

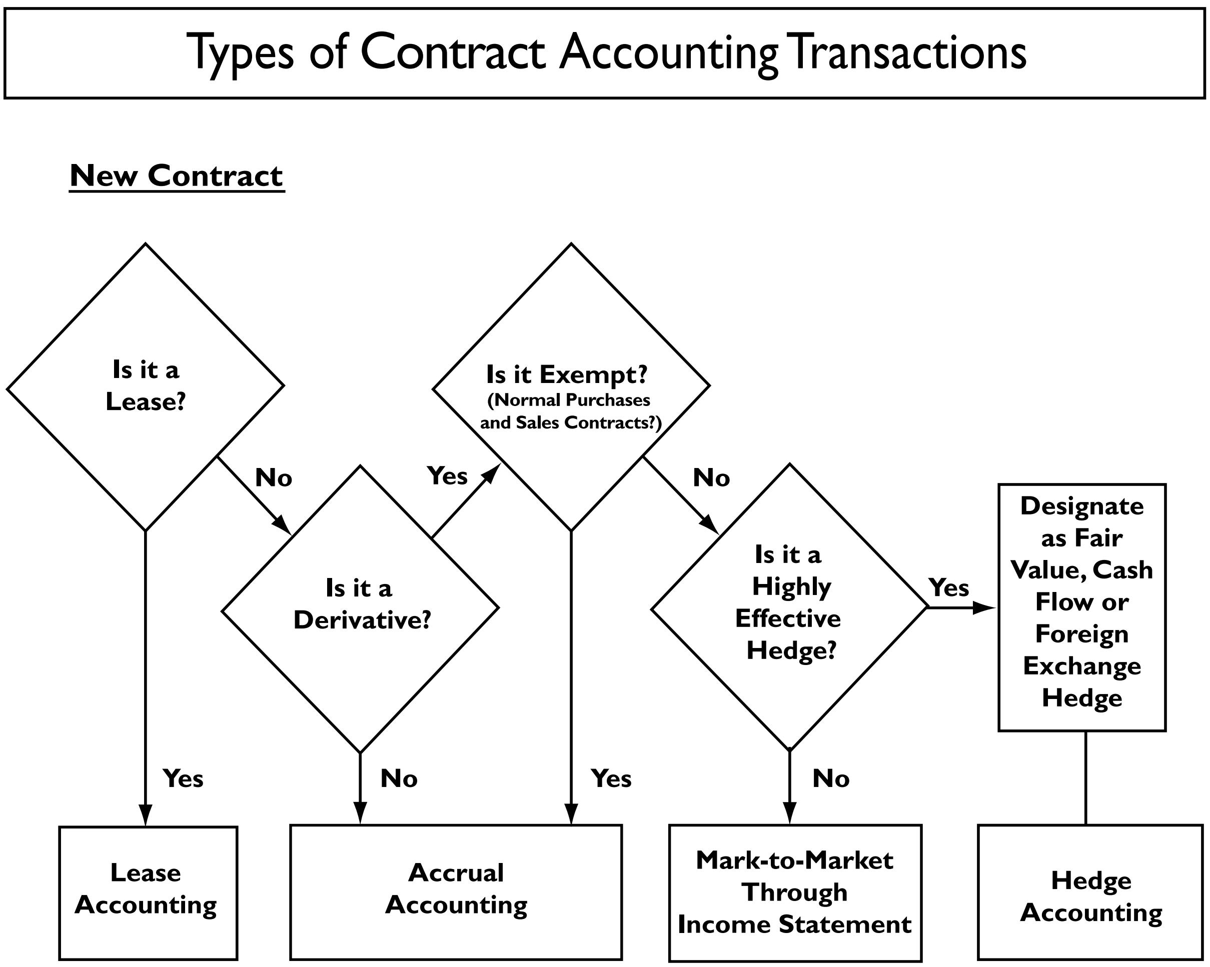
Impact of Recent Accounting Pronouncements

SFAS No. 133

On January 1, 2001, we adopted Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging

Activities", as amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities — Deferral of the Effective Date of FASB Statement No. 133 — an Amendment of FASB Statement No. 133", and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities — an Amendment of FASB Statement No. 133." Calpine currently holds six classes of derivative instruments that are impacted by the new pronouncement — foreign currency swaps, interest rate swaps, forward interest rate agreements, commodity financial instruments, commodity contracts, and physical options.

Consistent with the requirements of SFAS No. 133, we evaluate all of our contracts to determine whether or not they qualify as derivatives under the accounting pronouncement. For a given contract, there are typically three steps we use to determine its proper accounting treatment. First, based on the terms and conditions of the contract, as well as the applicable guidelines established by SFAS No. 133, we identify the contract as being either a derivative or non-derivative contract. Second, if the contract is not a derivative, we further identify its specific classification (e.g. whether or not it qualifies as a lease) and apply the appropriate non-derivative accounting treatment. Alternatively, if the contract does qualify as a derivative under the guidance of SFAS No. 133, we evaluate whether or not it qualifies for the "normal" purchases and sales exception (as described below). If the contract qualifies for the exception, we apply the traditional accrual accounting treatment. Finally, if the contract qualifies as a derivative and does not qualify for the "normal" purchases and sales exception, we apply the accounting treatment required by SFAS No. 133, which is outlined below in further detail. The graph below illustrates the process we use for the purposes of identifying the classification and subsequent accounting treatment of our contracts:



Classification Flow Chart

As an independent power producer primarily focused on generation of electricity using gas-fired turbines, Calpine's natural physical commodity position is "short" fuel (i.e., natural gas consumer) and "long" power capacity (i.e., electricity seller). Additionally, we also have a natural "long" crude position due to our petroleum reserves. To manage forward exposure to price fluctuation, we execute commodity derivative contracts as defined by SFAS No. 133. As we apply SFAS No. 133, derivatives can receive one of four treatments depending on associated circumstances: 1. exemption from SFAS No. 133 accounting treatment if these instruments qualify as "normal" purchases and sales contracts. 2. cash flow hedges. 3. fair value hedges. 4. undesignated derivatives.

Normal purchases and sales

Normal purchases and sales, as defined by paragraph 10 b. of SFAS No. 133 and amended by SFAS No. 138, are exempt from SFAS No. 133 accounting treatment. As a result, these contracts are not required to be recorded on the balance sheet at their fair values and any fluctuations in these values are not required to be reported within earnings. Probability of physical delivery from our generation plants, in the case of electricity sales, and to our generation plants, in the case of natural gas contracts, is required over the life of the contract within reasonable tolerances.

On June 27, 2001, the FASB cleared SFAS No. 133 Implementation Issue No. C15 dealing with a proposed electric industry normal purchases and sales exception for capacity sales transactions ("The Eligibility of Option Contracts in Electricity for the Normal Purchases and Normal Sales Exception"). On October 10, 2001, the FASB revised the criteria for qualifying for the "normal" exception. As a result of Issue No. C15, as revised, certain power purchase and/or sale agreements that are structured as capacity sales contracts are now eligible to qualify for the normal purchases and sales exception. Because we are "long" power capacity, we often enter into capacity sales contracts as a means to recover the costs incurred from maintaining and operating our power plants as well as the costs directly associated with the generation and sale of electricity to our customers. Under Issue No. C15, a capacity sales contract will qualify for the normal purchases and sales exception subject to certain conditions.

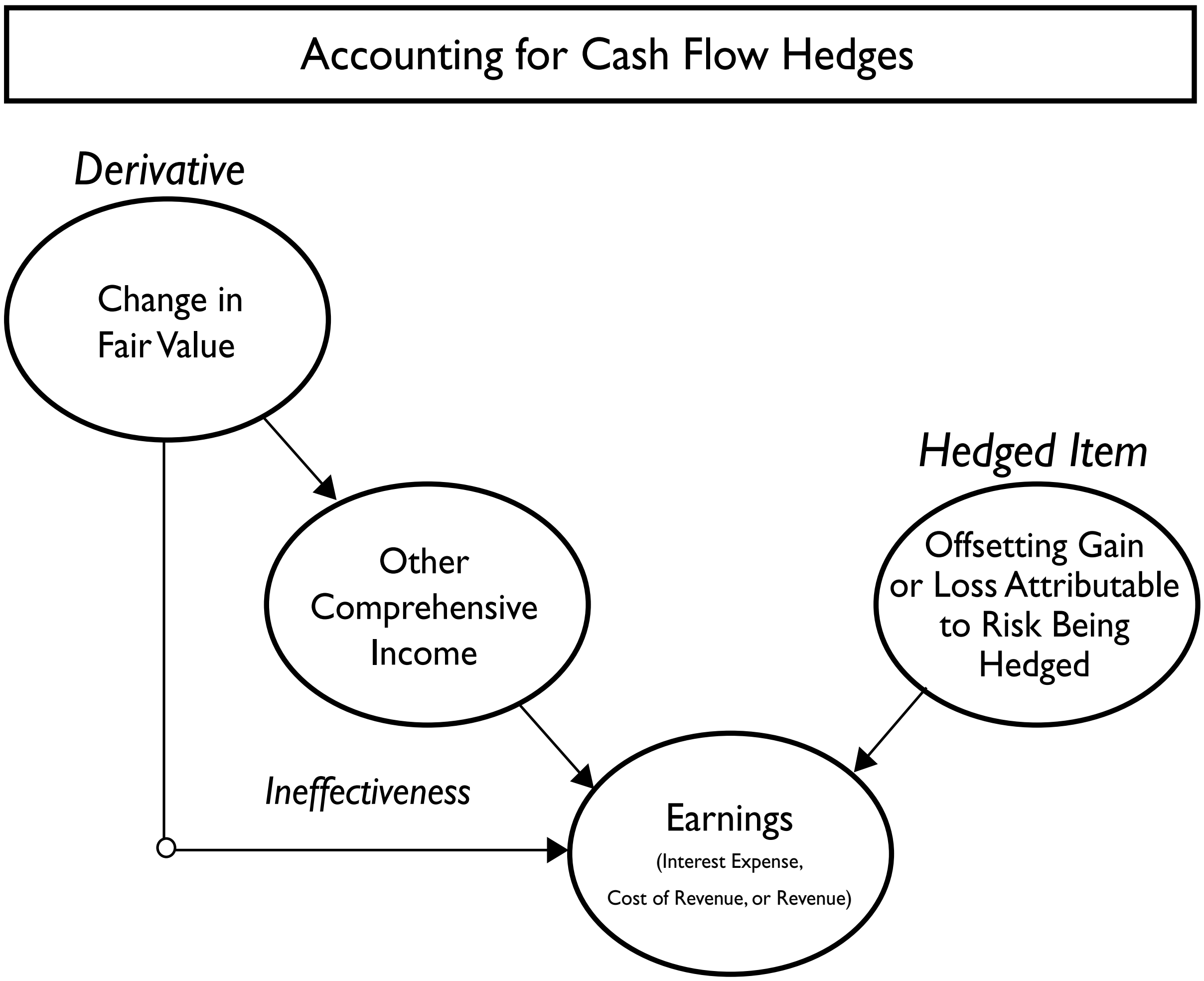
We expect that most of our capacity sales contracts will qualify for the normal purchases and sales exception.

Cash flow hedges and fair value hedges

Within the energy industry, cash flow and fair value hedge transactions typically use the same types of standard transactions (i.e., *offered* for purchase/sale in over-the-counter markets or commodity exchanges).

As further defined in SFAS No. 133, fair value hedge transactions hedge the exposure to changes in the fair value of either all or a specific portion of a recognized asset or liability or of an unrecognized firm commitment. The accounting treatment for fair value hedges requires reporting both the changes in fair values of a *hedged* item (the underlying risk) and the *hedging* instrument (the derivative designated to offset the underlying risk) on both the balance sheet and the income statement. On that basis, when a firm commitment is associated with a hedge instrument that attains 100% effectiveness (under the effectiveness criteria outlined in SFAS No. 133), there is no net earnings impact because the earnings caused by the changes in fair value of the hedged item will move in an equal, but opposite, amount as the earnings caused by the changes in fair value of the hedging instrument. In other words, the earnings volatility caused by the underlying risk factor will be neutralized because of the hedge. For example, if Calpine wants to manage the price risk (i.e. the risk that market electric rates will rise, making the fixed price contract less valuable) associated with all or a portion of a fixed price power sale that has been identified as a "normal" transaction (as described above), it might create a fair value hedge by purchasing fixed price power. From that date and time forward until delivery, the change in fair value of the hedged item and hedge instrument will be reported in earnings with asset/liability offsets on the balance sheet. If there is 100% effectiveness, there is no net earnings impact. If there is less than 100% effectiveness, the fair value change of the hedged item (the underlying risk) and the hedging instrument (the derivative) will likely be different and the "ineffectiveness" will result in a net earnings impact.

As further defined in SFAS No. 133, cash flow hedge transactions hedge the exposure to variability in expected future cash flows (i.e., in Calpine's case, the price variability of forecasted purchases of gas and sales of power, as well as interest rate and foreign exchange rate exposure). In the case of cash flow hedges, the hedged item (the underlying risk) is generally unrecognized (i.e., not recorded on the balance sheet prior to delivery), and any changes in this fair value, therefore, will not be recorded within earnings. Conceptually, if a cash flow hedge is effective, this means that a variable such as movements in power prices has been effectively fixed, so that any fluctuations will have no net result on either cash flows or earnings. Therefore, if the changes in fair value of the hedged item are not recorded in earnings, then the changes in fair value of the hedging instrument (the derivative) must also be excluded from the income statement, or else a one-sided net impact on earnings will be reported, despite the fact that the establishment of the effective hedge results in no net economic impact. To prevent such a scenario from occurring, SFAS No. 133 requires that the fair value of a derivative instrument designated as a cash flow hedge be recorded as an asset or liability on the balance sheet, but with the offset reported as part of other comprehensive income ("OCI"), to the extent that the hedge is effective under SFAS No. 133. Similar to fair value hedges, any ineffectiveness portion will be reflected in earnings. The graph below illustrates the process used to account for derivatives designated as cash flow hedges:



Certain contracts could either qualify for exemption from SFAS No. 133 accounting as normal purchases or sales or be designated as effective hedges. Our marketing and fuels groups generally transact with load serving entities and other end-users of electricity and with fuel suppliers, respectively, in physical contracts where delivery is expected. These transactions are structured as normal purchases and sales, when possible. Conversely, our CES risk management desks generally transact in over-the-counter or exchange traded contracts, in hedging transactions. These transactions are designated as hedges when possible, notwithstanding the fact that some might qualify as normal purchases or sales.

Undesignated derivatives

The fair values and changes in fair values of undesignated derivatives are recorded in earnings, with the corresponding offsets recorded as derivative assets or liabilities on the balance sheet. Calpine has the following types of undesignated transactions:

- transactions are executed at a location where Calpine does not have an associated natural long (generation capacity) or short (fuel consumption requirements) position of sufficient quantity for the entire term of the transaction (e.g., power sales where Calpine does not own generating assets or intend to acquire transmission rights for delivery from other assets for a portion of the contract term), and

- transactions executed with the intent to profit from short-term price movements

- Discontinuance (de-designation) of hedge treatment prospectively consistent with paragraphs 25 and 32 of SFAS No. 133. In circumstances where we believe the hedge relationship is no longer necessary, Calpine will remove the hedge designation and close out the hedge positions by entering into an equal and offsetting derivative position. Prospectively, the two derivative positions should generally have no net earnings impact because the changes in their fair values are offsetting.

Accumulated Other Comprehensive Income

Accumulated other comprehensive income ("AOCI") includes the following components: (i) unrealized pre-tax gains/losses, net of reclassification-to-earnings adjustments, from effective cash flow hedges as designated pursuant to SFAS No. 133, (see Note 19 — "Derivative Instruments" in the Notes to the Consolidated Financial Statements); (ii) unrealized pre-tax gains/losses that result from the translation of foreign subsidiaries' balance sheets from the foreign functional currency (primarily C$) to our consolidated reporting currency (US $); and (iii) the taxes associated with the unrealized gains/losses from items (i) and (ii). See Note 17 — "Stockholders' Equity" in the Notes to the Consolidated Financial Statements for further information.

One result of the Company's adoption on January 1, 2001, of SFAS No. 133 has been volatility in the AOCI component of Stockholders' Equity on the balance sheet. As explained in Notes 17 and 19 to our consolidated financial statements, our AOCI balances are primarily related to our cash flow hedging activity, which is highlighted within our discussion of "Impact of Recent Accounting Pronouncements". The quarterly balances for 2001 in AOCI related to cash flow hedging activity are summarized in the table below (in thousands).

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31**
AOCI balances related to cash flow hedging	$(53,570)	$103,352	$(187,560)	$(183,377)

Under SFAS No. 133 until the effects of an associated hedged item are recognized in earnings, the change in fair value of each derivative, other than exempted derivatives such as normal purchases and sales, is recorded in AOCI or current earnings with an offset to an asset or liability. The accounting treatment varies with the designation of the derivative as summarized below:

- In the case of fair value hedges, the change in fair value is recorded in current earnings with an offset to an asset or liability; however, uniquely for fair value hedges, the change in fair value of the hedged item is also recorded in current earnings with an offset to an asset or liability. If the hedge is perfectly effective, the two entries to earnings will be equal and offsetting so that there is no net effect on earnings.

- For cash flow hedges, the effective portion of the change in fair value of the hedge instrument is recorded in AOCI, net of the tax impact, which is recorded as deferred taxes. In contrast to a fair value hedge, however, the hedged item is generally not recorded on the balance sheet prior to delivery or settlement, but if it is, it is recorded at historical cost, not market value. Neither the effective portion of the hedge nor the change in fair value of the hedged item are recorded in earnings prior to delivery or settlement.

- For trading activity or other derivatives not designated as hedges, the change in fair value is recorded in current earnings with an offset to an asset or liability.

The effective portion of cash flow hedges stays on the balance sheet in AOCI in Stockholders' Equity until the effects of an associated hedged item are recognized in earnings. This is illustrated in the example below. However, since AOCI contains the cash flow hedge instrument but excludes the hedged item, it is not appropriate to conclude that either a gain or a loss in AOCI will eventually produce a net gain or loss in earnings. To illustrate this, consider the following simplified example:

Example of a Cash Flow Hedging Transaction

The Company on October 1, 2001, enters into a fixed price 100-MW power contract with a two-year term with deliveries commencing January 1, 2002. Because the power price is fixed, the Company decides to acquire fixed price gas to assure a positive spark spread, the margin between the value of the electricity sold and the cost of fuel to generate that electricity. Failure to lock in the price of natural gas could lead to losses if gas prices were to rise significantly over the term of the power sales agreement. In our example, we choose on October 1, 2001, to enter into a swap transaction to convert spot or index gas to a fixed price of $3.50 per MMBtu on a monthly basis from January 2002 to December 2003. Assume gas volume is 500,000 MMBtus per month. We designate the swap as a cash flow hedge of our future gas requirements.

Scenario 1: At December 31 gas prices have decreased to an average of $3.00 over the term of the swap agreement and hold at that level during the month of January 2002.

In Scenario 1 the change in fair value of the gas contract would be out-of-the-money by $5,400,000 at December 31, 2001, computed as follows: 500,000 MMBtus/mo. multiplied by 24 months, multiplied by the gas price decline ($3.00 minus $3.50), multiplied by the average present value factor (assume 90%). This results in a loss of $5,400,000.

We would record a liability of $5,400,000 on our balance sheet (current and non-current components) with the corresponding offset as a debit (reduction) to AOCI of $3,510,000 ($5,400,000, net of tax effect of $1,890,000, assuming a 35% tax rate) and a debit (decrease) to deferred tax of $1,890,0000. Thus, in Scenario 1 we have an unrealized pre-tax loss of $5,400,000 that, assuming no further change in gas prices, will be reclassified to earnings as swap settlements occur over the following 24 months.

In January, we realize a loss of $250,000 on the swap settlement for January 2002 calculated as follows: 500,000 mm Btu's multiplied by a realized loss on gas ($3.00 minus $3.50). However, to provide our plant with fuel, we actually purchase gas at the index rate of $3.00 per MMBtu. Our total fuel expense for January is:

Fuel cost purchased (500,000 MMBtus times $3.00)	$1,500,000
(Gain)/Loss on swap	250,000
Total fuel cost	$1,750,000
Total fuel cost in $/MMBtu	$ 3.50

Scenario 2: At December 31 gas prices have increased to an average of $4.00 over the term of the swap agreement and hold at that level during the month of January 2002.

In Scenario 2 the change in fair value of the gas contract would be in-the-money by $5,400,000 at December 31, 2001, computed as follows: 500,000 MMBtus/mo. multiplied by 24 months, multiplied by the gas price increase ($4.00 minus $3.50), multiplied by the average present value factor (assume 90%). This results in a gain of $5,400,000.

We would record an asset of $5,400,000 on our balance sheet (current and non-current components) with the corresponding offset as a credit (increase) to AOCI of $3,510,000 ($5,400,000, net of tax effect of $1,890,000, assuming a 35% tax rate) and a credit (increase) to deferred tax of $1,890,0000. Thus, in Scenario 2 we have an unrealized pre-tax gain of $5,400,000 that, assuming no further change in gas prices, will be reclassified to earnings as swap settlements occur over the following 24 months.

In January, we realize a gain of $250,000 on the swap settlement for January 2002 calculated as follows: 500,000 MMBtus multiplied by a realized gain on gas ($4.00 minus $3.50). However, to provide our plant with fuel, we actually purchase gas at the index rate of $4.00 per MMBtu. Our total fuel expense for January is:

Fuel cost purchased (500,000 MMBtus times $4.00)	$2,000,000
(Gain)/Loss on swap	(250,000)
Total fuel cost	$1,750,000
Total fuel cost in $/MMBtu	$ 3.50

The important point to note from the example is that by hedging we locked in a fuel price of $3.50 per MMBtu which was realized regardless of the direction of gas price fluctuations after the hedge was established. In both scenarios 1 and 2, we realized a net $3.50 fuel price. The unrealized gain or loss in AOCI presents only half of the accounting impact because the hedged item (the purchase of fuel at index) is excluded from the AOCI calculation, and ultimately, the unrealized gain or loss in AOCI leads to the same net realized result. Accordingly, we believe the AOCI balance resulting from cash flow hedging activity is not, in and of itself, a reliable indicator of net future gains or losses to be realized after considering the effects of the hedged item.

Cash flow impact of SFAS No. 133 entries

Prior to delivery or settlement, there is no net cash flow impact resulting from the SFAS No. 133 entries to record derivatives as assets or liabilities, and in the case of cash flow hedges to AOCI on the balance sheet, or from marking-to-market gains or losses to earnings. All cash flow activity from derivatives is recorded within "Cash flows from operating activities" within our Consolidated Statements of Cash Flows. The derivative components of our cash flow activity for 2001 are summarized below:

Net Income from SFAS No. 133:	
Electric power derivative mark-to-market gain	$ 98,053
Natural gas derivative mark-to-market gain	36,693
Interest expense	4,282
Other income	(7,083)
Provision for income taxes	(46,181)
Cumulative effect of a change in accounting principle, net of tax	1,036
Total Net Income from SFAS No. 133	$ 86,800

Adjustments to reconcile net income to net cash provided by operating activities:	
Deferred income taxes, net	$ (69,513)
Other comprehensive income, net of tax	(183,377)
Change in operating assets and liabilities:	
Current derivative assets	(763,162)
Long-term derivative assets	(564,952)
Current derivative liabilities	625,339
Long-term derivative liabilities	822,848
Other assets	(3,725)
Accounts payable and accrued expenses	591
Other current liabilities	(1,190)
Net cash used by operating activities from SFAS No. 133	$ (50,341)

The net cash outlay from derivative activities was caused primarily by the cash settlement of several forward interest rate agreements related to our 8 ½% Senior Notes Due 2011 and our 8 ½% Senior Notes Due 2008 totaling $25.9 million and the early termination and cash settlement of certain of our interest rate swaps in connection with the sale and leaseback of our Broad River and RockGen facilities totaling $24.4 million.

See Note 19 of the Notes to Consolidated Financial Statements for the financial statement effects of SFAS No. 133.

SFAS No. 141

In June 2001 the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets", which supersedes APB Opinion No. 17, "Intangible Assets". SFAS No. 142 eliminates the current requirement to amortize goodwill and indefinite-lived intangible assets, extends the allowable useful lives of certain intangible assets, and requires impairment testing and recognition for goodwill and intangible assets. SFAS No. 142 will apply to goodwill and other intangible assets arising from transactions completed both before and after its effective date. The provisions of SFAS No. 142 are required to be applied starting with fiscal years beginning after December 15, 2001. As of December 31, 2001, the Company's unamortized goodwill and other intangible assets balance was $261.9 million, and was being amortized over periods ranging from 3 to 35 years. As a result of SFAS No. 142, the Company currently estimates that the elimination of goodwill and other intangible assets amortization will result in pre-tax savings of approximately $12.1 million in 2002. The Company has not yet finalized the financial statement impact of SFAS No. 142.

SFAS No. 142

In June 2001 the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets", which supersedes APB Opinion No. 17, "Intangible Assets". SFAS No. 142 eliminates the current requirement to amortize goodwill and indefinite-lived intangible assets, extends the allowable useful lives of certain intangible assets, and requires impairment testing and recognition for goodwill and intangible assets. SFAS No. 142 will apply to goodwill and other intangible assets arising from transactions completed both before and after its effective date. The provisions of SFAS No. 142 are required to be applied starting with fiscal years beginning after December 15, 2001. As of December 31, 2001, the Company's unamortized goodwill and other intangible assets balance was $29.4 million, and was being amortized over periods ranging from 10 to 20 years. As a result of SFAS No. 142, the Company currently estimates that the elimination of goodwill and other intangible assets amortization will result in pre-tax savings of $1.8 million in 2002. The Company has not yet finalized the financial statement impact of SFAS No. 142.

SFAS No. 143

In June 2001 the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations", which amends SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies". SFAS

No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. SFAS No. 143 is effective for financial statements issued for fiscal years beginning after June 15, 2002. We do not believe that SFAS No. 143 will have a material effect on our consolidated financial statements.

SFAS No. 144

In August 2001 the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", which supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of", and the accounting and reporting provisions of APB Opinion No. 30, "Reporting the Results of Operations — Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions", for the disposal of a segment of a business (as previously defined in that APB Opinion). SFAS No. 144 establishes a single accounting model, based on the framework established in SFAS No. 121, for long-lived assets to be disposed of by sale. SFAS No. 144 also resolves several significant implementation issues related to SFAS No. 121, such as eliminating the requirement to allocate goodwill to long-lived assets to be tested for impairment and establishing criteria to define whether a long-lived asset is held for sale. SFAS No. 144 is effective for financial statements issued for fiscal years beginning after December 15, 2001. We do not believe that SFAS No. 144 will have a material effect on our consolidated financial statements.

Summary of Key Activities

Mergers and Acquisitions

Date	Description	Seller	Price
4/3/01	Acquired WRMS Engineering, Inc.	WRMS shareholders	$7.8 million, including the assumed indebtedness of WRMS.
4/17/01	Acquired certain natural gas assets of The Bayless Companies and a number of individuals from Bayless began employment with the Company	The Bayless Companies and a number of individuals	$35.1 million
4/19/01	Merged with Encal Energy Ltd.	Encal shareholders	US$1.1 billion, including the assumed indebtedness of Encal
8/24/01	Acquired the 1,200-megawatt Saltend Energy Centre	Entergy Corporation	US$818.1 million (at exchange rates at the closing of the acquisition)
9/12/01	Acquired remaining 33.3% interests in Hog Bayou and Pine Bluff Energy Centers	Intergen (North America), Inc.	$9.6 million
9/20/01	Acquired 100% interest in the 250-megawatt Island Cogeneration facility and 50% interest in the 50-megawatt Whitby Cogeneration facility	Westcoast Energy Inc.	US$212.1 million (at exchange rates at the closing of the acquisition)
10/16/01	Acquired California Energy General Corporation and CE Newburry, Inc.	MidAmerican Energy Holdings Company	$22.0 million

Date	Description	Seller	Price
10/22/01	Completed the acquisition of 100% of the voting stock of Michael Petroleum Corporation, natural gas exploration and production company	Shareholders of Michael Petroleum Corporation	$315.8 million and $54.5 million assumption of debt
11/5/01	Acquired Highland Energy Company	Entergy Power Gas Operations Corporation and Louis Morrison III	$4.5 million
11/6/01	Acquired remaining 50% interest in Delta Energy Center, Metcalf Energy Center and Russell City Energy Center	Bechtel Enterprises Holdings, Inc.	Approximately $154 million and the assumption of approximately $141 million of debt
12/14/01	Acquired certain natural gas assets of Whiting Petroleum Corporation and other minority partner interest owners	Whiting Petroleum Corporation and other minority partner interest owners	Approximately $8 million

Finance

Sales of Senior Notes:

Date	Offering	Rate	Due	Issuer
2/15/01	US$1.15 billion(1)	8.500%	2011	Calpine Corporation
4/25/01	US$1.5 billion(2)	8.500%	2008	Calpine Canada Energy Finance ULC
10/16/01	US$530 million(2)	8.500%	2008	Calpine Canada Energy Finance ULC
10/16/01	US$850 million(1)	8.500%	2011	Calpine Corporation
10/18/01	C$200 million	8.750%	2007	Calpine Canada Energy Finance ULC
10/18/01	£200 million	8.875%	2011	Calpine Canada Energy Finance II ULC
10/18/01	€175 million	8.375%	2008	Calpine Canada Energy Finance II ULC

(1) Issued as fungible tranches by Calpine with the same CUSIP number and identical economic terms.

(2) Issued as fungible tranches by our subsidiary, Calpine Canada Energy Finance ULC, with the same CUSIP number and identical economic terms.

Redemption of Senior Note and Note Repayment:

Date	Amount	Description
6/7/01	$105 million	9.250% Senior Notes Due 2004; 100% of the principal amount plus accrued interest to the redemption date
3/13/02	$64.8 million	Michael Petroleum Note Payable

Calpine Corporation's Sale of Zero-Coupon Convertible Debentures Due 2021:

Date	Amount	Conversion Price	Use of Proceeds
4/30/01	$ 1.0 billion	$75.35 per common share	Refinance certain debt and for working capital and general corporate purposes

Repurchases of Zero-Coupon Convertible Debentures Due 2021:

Date	Amount
12/14/01	$60 million
12/17/01	$62 million
January 2, 2002, through February 11, 2002	$192.5 million

Sale/Leaseback Transactions:

Date	Proceeds	Facility
10/18/01	$800.0 million	South Point Energy Center, Broad River Energy Center and RockGen Energy Center

Calpine Corporation's Sale of 4% Convertible Senior Notes Due 2006:

Date	Offering	Conversion Price	Use of Proceeds
12/26/01	$1 billion	$18.07 per common share	Retire Zero-Coupon Convertible Debentures Due 2021 and for general corporate purposes
12/31/01	$100 million	$18.07 per common share	For general corporate purposes
1/3/02	$100 million	$18.07 per common share	For general corporate purposes

Working Capital Credit Facility:

Date	Amount	Security	Use of Proceeds
3/12/02	$1.6 billion $400 million	Natural gas properties, Saltend Power Plant and our equity investment in 9 U.S. power plants	Finance capital expenditures and other general corporate purposes

Other:

Date	Description
9/28/01	Announced the amendment of certain provisions of the Stockholder Rights Agreement.
10/2/01	Moody's Investors Service upgraded corporate credit and senior unsecured notes to Baa3 from Ba1.
12/14/01	Moody's Investors Service downgraded corporate credit and senior unsecured notes from Baa3 to Ba1.
12/19/01	Fitch, Inc. lowered the credit rating on senior unsecured debt rating from BBB- to BB+, and it lowered the rating on convertible trust preferred securities from BB to BB-.
3/12/02	Fitch, Inc. lowered the credit rating on senior unsecured debt from BB+ to BB, and it lowered the rating on convertible trust preferred securities from BB- to B.
3/25/02	Standard & Poor's downgraded corporate credit rating from BB+ to BB, and senior unsecured debt from BB+ to B+.

Power Plant Development and Construction

Date	Project	Description
1/17/01	850-megawatt Augusta Energy Center located in Augusta, Georgia	Announced plans for development
1/26/01	565-megawatt Washington Parish Energy Center located near Bogalusa, Louisiana	Announced acquisition of development rights from Cogentrix
2/12/01	590-megawatt Osprey Energy Center located in Auburndale, Florida	Application approved in Florida Public Service Commission need determination hearing
2/13/01	600-megawatt Riverside Energy Center located near Beloit, Wisconsin	Announced plans for development
3/16/01	336-megawatt Blue Spruce Energy Center located east of Denver, Colorado	Announced plans for development
3/22/01	600-megawatt Rocky Mountain Energy Center located in Weld County, Colorado	Announced plans for development
3/27/01	1,007-megawatt Deer Park Energy Center located in Deer Park, Texas	Announced plans for development

Date	Project	Description
3/29/01	1,065-megawatt East Altamont Energy Center located in Alameda County, California	Filed an Application For Certification ("AFC") with the California Energy Commission ("CEC")
4/11/01	750-megawatt Pastoria Energy Center located in Kern County, California	Acquired the development rights from Enron North America
4/17/01	248-megawatt Goldendale Energy Center located in Goldendale, Washington	Acquired the development rights from National Energy Systems Company
5/9/01	525-megawatt Westbrook Energy Center located in Westbrook, Maine	Announced commercial operation
5/15/01	1,030-megawatt Berrien Energy Center located in Berrien, Michigan	Announced plans for development
5/23/01	600-megawatt Russell City Energy Center located in Hayward, California	Filed an AFC with the CEC and announced plans for development
6/4/01	545-megawatt Lost Pines 1 Energy Center located in Bastrop County, Texas	Announced initial operation
6/5/01	135-megawatt Gilroy Peaking Energy Center located in Gilroy, California	Announced initiation of construction activities
6/7/01	555-megawatt South Point Energy Center located in Mohave County, Arizona	Announced full operation
6/8/01	670-megawatt Inland Empire Energy Center located in southwestern Riverside County, California	Announced plans for development
6/20/01	600-megawatt Metcalf Energy Center located in San Jose, California	Announced that the Presiding Members' Proposed Decision recommends that the full five-member CEC approve the Metcalf Energy Center
6/28/01	590-megawatt Osprey Energy Center located in Auburndale, Florida	Announced that Florida's Power Plant Siting Board granted final state regulatory approval for the Osprey Energy Center
7/2/01	547-megawatt Sutter Energy Center located near Yuba City, California	Announced commercial operation
7/9/01	555-megawatt Los Medanos Energy Center located in Pittsburg, California	Announced initial operation
7/10/01	510-megawatt Otay Mesa Generating Project located in San Diego County, California	Acquired from the PG&E National Energy Group
7/11/01	600-megawatt Russell City Energy Center located in Hayward, California	AFC met the CEC's data adequacy requirements; project approved for expedited review
7/11/01	180-megawatt Los Esteros Critical Energy Facility located in San Jose, California	Announced plans for development

Date	Project	Description
7/11/01	247-megawatt Hog Bayou Energy Center located in Mobile, Alabama	Announced commercial operation
7/16/01	591-megawatt Aries Power Project located near Pleasant Hill, Missouri	Announced simple-cycle operation (320 megawatts)
7/17/01	900-megawatt Sherry Mills Energy Center located in Wood County, Wisconsin	Announced plans for development
7/30/01	628-megawatt Channel Energy Center located in Houston, Texas	Announced simple-cycle operation (190 megawatts)
8/2/01	115-megawatt Auburndale Expansion located in Polk County, Florida	Announced initiation of full-scale construction activities
8/8/01	460-megawatt RockGen Energy Center located near Cambridge, Wisconsin	Announced full operation
8/23/01	750-megawatt Pastoria Energy Center located in Kern County, California	Announced groundbreaking
8/24/01	630-megawatt Wawayanda Energy Center located in the Town of Wawayanda, New York	Announced filing of Article X Application
9/5/01	840-megawatt Broad River Energy Center located in Gaffney, South Carolina	Announced commercial operation of 300-megawatt expansion
9/24/01	213-megawatt Pine Bluff Energy Center located south of Little Rock, Arkansas	Announced commercial operation
9/24/01	602-megawatt Metcalf Energy Center located in San Jose, California	CEC voted unanimously to approve the license
10/30/01	49.5-megawatt Fourmile Hill Geothermal Project located in the Glass Mountain Known Geothermal Resource Area in California	Announced plans for development
11/1/01	905-megawatt Palmetto Energy Center located in York County, South Carolina	Announced plans for development
11/1/01	1,060-megawatt Central Valley Energy Center located in San Joaquin, California	Announced filing of AFC with the CEC
11/13/01	590-megawatt Osprey Energy Center located in Auburndale, Florida	Announced groundbreaking
11/21/01	1,058-megawatt Chippokes Energy Center located in Surry County, Virginia	Announced plans for development

Turbine Purchases

Date of Announcement	Turbines	Manufacturer
4/19/01	35 model 7FB and 11 model 7FA gas turbines	GE Power Systems
8/9/01	27 steam turbines	Siemens Westinghouse
8/22/01	19 steam turbines	Toshiba International Corporation

Turbine Cancellations

Date of Announcement	Reduction in Capital Spending	Earnings Effect
3/12/02	$1.2 billion in 2002 $1.8 billion in 2003	$161 million pre-tax charge in 2002

Power Contracts

Date of Announcement	Purchaser	Power Purchased	Term of Contract(s)	Facility Supplying Power
5/9/01	San Francisco Public Utilities Commission	50 megawatts	5 years	Not specified
7/17/01	Reliant Energy Services, Inc.	1,000 megawatts	5 years	ERCOT system of plants
7/19/01	Excelon Generation's Power Team	100 megawatts	10 years	Morris Power Plant
12/20/01	Six major industrial customers	More than 500 megawatts	Each of several agreements is for a term of one to two years	ERCOT system of plants

Gas Storage Agreement

Date of Announcement	Gas Storage Provider	Storage Facility	Storage Provided Under the Agreement
1/11/01	Western Hub Properties LLC's subsidiary, Lodi Gas Storage, LLC	Lodi Gas Storage facility near Lodi, California	Up to 4 billion cubic feet of working gas inventory

Management Developments

Date of Announcement	Individual	Description
4/19/01	Orville Wright	Retirement from the Board of Directors
7/16/01	Michael Polsky	Resignation from the Board of Directors and as an officer of the Company
7/17/01	Gerald Greenwald	Appointment to the Board of Directors
7/24/01	Robert D. Kelly	Named President of Calpine Finance Company
11/5/01	David Johnson	Resignation as President and Chief Executive Officer of Calpine Canada

Annual Meeting of Stockholders on May 17, 2001

Stockholders' Voting Results

- Elected Ann B. Curtis and Kenneth T. Derr as Class II Directors for a three-year term expiring 2004
- Approved the amendment to the Amended and Restated Certificate of Incorporation to increase the number of authorized shares of Common Stock, par value $.001 per share, from 500,000,000 to 1,000,000,000
- Ratified the appointment of Arthur Andersen LLP as independent accountants for the fiscal year ending December 31, 2001

See "Item 1. — Business — Recent Developments" for a discussion of the Enron bankruptcy, our revised capital expenditure program, our recent capital market offerings, the California power market, the PG&E bankruptcy, the CPUC proceedings regarding QF market pricing, the California long-term supply contracts, the FERC investigation into California wholesale markets and litigation.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors
and Stockholders of Calpine Corporation:

We have audited the accompanying consolidated balance sheets of Calpine Corporation (a Delaware corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the balance sheet of Encal Energy Ltd. ("Encal"), a company acquired on April 19, 2001, in a transaction accounted for as a pooling-of-interests, as discussed in Note 2 to the financial statements, as of December 31, 2000, or the related statements of operations, stockholders' equity and cash flows for each of the two years in the period ended December 31, 2000. Such statements are included in the consolidated financial statements of Calpine Corporation and reflect total assets and total revenues of 5.7 percent and 10.4 percent, respectively, in 2000, and total revenues of 13.8 percent in 1999 of the related consolidated totals. These statements were audited by other auditors, whose report has been furnished to us and our opinion, insofar as it relates to amounts included for Encal, is based solely upon the report of the other auditors.

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

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

As explained in Note 2 to the financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities by adopting Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."

ARTHUR ANDERSEN LLP

San Jose, California
February 6, 2002
(except for Note 24 as to which the date is March 22, 2002)

REPORT OF INDEPENDENT CHARTERED ACCOUNTANTS

The Board of Directors of Encal Energy Ltd.

We have audited the consolidated balance sheets of Encal Energy Ltd. as of December 31, 2000, 1999 and 1998 and the related consolidated statements of earnings, changes in shareholders' equity, and cash flows for each of the three years in the three year period ended December 31, 2000. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. 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, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Encal Energy Ltd. at December 31, 2000, 1999 and 1998, and the consolidated results of its operations and its cash flows for each of the three years in the three year period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

Ernst and Young LLP

Calgary, Canada
February 16, 2001

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
December 31, 2001 and 2000

	2001	2000
	(In thousands, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,525,417	$ 596,077
Accounts receivable, net of allowance of $15,422 and $11,555	966,080	727,893
Margin deposits and other prepaid expenses	480,656	27,515
Inventories	78,862	44,456
Current derivative assets	763,162	—
Other current assets	193,525	41,165
Total current assets	4,007,702	1,437,106
Restricted cash	95,833	88,618
Notes receivable, net of current portion	158,124	217,927
Project development costs	179,783	38,597
Investments in power projects	378,614	205,621
Deferred financing costs	210,811	112,049
Property, plant and equipment, net	15,384,990	7,979,160
Long-term derivative assets	564,952	—
Other assets	328,486	244,125
Total assets	$21,309,295	$10,323,203
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,283,843	$ 843,641
Accrued payroll and related expenses	57,285	53,667
Accrued interest payable	160,115	77,878
Income taxes payable	—	63,409
Notes payable and borrowings under lines of credit, current portion	23,238	1,087
Capital lease obligation, current portion	2,206	1,985
Zero-Coupon Convertible Debentures Due 2021	878,000	—
Construction/project financing, current portion	—	58,486
Current derivative liabilities	625,339	—
Other current liabilities	198,812	149,080
Total current liabilities	3,228,838	1,249,233
Notes payable and borrowings under lines of credit, net of current portion	74,750	455,067
Capital lease obligation, net of current portion	207,219	208,876
Construction/project financing, net of current portion	3,393,410	1,473,869
Convertible Senior Notes Due 2006	1,100,000	—
Senior notes	7,049,038	2,551,750
Deferred income taxes, net	964,346	618,529
Deferred lease incentive	57,236	60,676
Deferred revenue	154,381	92,511
Long-term derivative liabilities	822,848	—
Other liabilities	76,247	30,529
Total liabilities	17,128,313	6,741,040
Commitments and contingencies (see Note 21)		
Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts	1,123,024	1,122,490
Minority interests	47,389	37,576
Stockholders' equity:		
Preferred stock, $.001 par value per share; authorized 10,000,000 shares; issued and outstanding one share in 2001 and 2000	—	—
Common stock, $.001 par value per share; authorized 1,000,000,000 shares in 2001 and 500,000,000 shares in 2000; issued and outstanding 307,058,751 shares in 2001 and 300,074,078 shares in 2000	307	300
Additional paid-in capital	2,040,836	1,896,987
Retained earnings	1,196,000	547,895
Accumulated other comprehensive loss	(226,574)	(23,085)
Total stockholders' equity	3,010,569	2,422,097
Total liabilities and stockholders' equity	$21,309,295	$10,323,203

The accompanying notes are an integral part of these consolidated financial statements.

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31,		
	2001	2000	1999
	(In thousands, except per share amounts)		
Revenue:			
Electric generation and marketing revenue			
Electricity and steam revenue	$2,432,278	$1,702,493	$ 760,325
Sales of purchased power	4,056,354	370,481	23,157
Electric power derivative mark-to-market gain	98,053	—	—
Total electric generation and marketing revenue	6,586,685	2,072,974	783,482
Oil and gas production and marketing revenue			
Oil and gas sales	427,454	336,133	141,567
Sales of purchased gas	520,723	108,329	14,416
Total oil and gas production and marketing revenue	948,177	444,462	155,983
Income from unconsolidated investments in power projects	8,763	24,639	36,593
Other revenue	46,353	5,026	7,426
Total revenue	7,589,978	2,547,101	983,484
Cost of revenue:			
Electric generation and marketing expense			
Plant operating expense	327,389	196,213	120,619
Royalty expense	27,492	32,325	13,767
Purchased power expense	3,708,845	358,649	20,681
Total electric generation and marketing expense	4,063,726	587,187	155,067
Oil and gas production and marketing expense			
Oil and gas production expense	113,387	89,442	52,792
Purchased gas expense	492,587	108,331	12,646
Total oil and gas production and marketing expense	605,974	197,773	65,438
Fuel expense			
Cost of oil and natural gas burned by power plants	1,152,785	612,947	268,734
Natural gas derivative mark-to-market gain	(36,693)	—	—
Total fuel expense	1,116,092	612,947	268,734
Depreciation, depletion and amortization expense	338,244	230,787	134,907
Operating lease expense	118,873	69,419	33,594
Other expense	15,549	2,020	6,909
Total cost of revenue	6,258,458	1,700,133	664,649
Gross profit	1,331,520	846,968	318,835
Project development expense	35,860	27,556	10,712
General and administrative expense	157,370	102,551	55,667
Merger expense	41,627	—	—
Income from operations	1,096,663	716,861	252,456

	For the Years Ended December 31,		
	2001	2000	1999
	(In thousands, except per share amounts)		
Interest expense	165,360	74,683	103,248
Distributions on trust preferred securities	61,334	44,210	2,565
Interest income	(72,608)	(39,901)	(24,106)
Other income	(43,882)	(3,461)	(5,109)
Minority interest, net	136	2,684	—
Income before provision for income taxes	986,323	638,646	175,858
Provision for income taxes	345,261	264,809	68,058
Income before extraordinary gain/(charge) and cumulative effect of a change in accounting principle	641,062	373,837	107,800
Extraordinary gain/(charge), net of tax (provision)/benefit of $(3,606), $796 and $793	6,007	(1,235)	(1,150)
Cumulative effect of a change in accounting principle, net of tax benefit of $669	1,036	—	—
Net income	$ 648,105	$ 372,602	$ 106,650
Basic earnings per common share:			
Weighted average shares of common stock outstanding	303,522	281,070	225,375
Income before extraordinary gain/(charge) and cumulative effect of a change in accounting principle	$ 2.11	$ 1.33	$ 0.48
Extraordinary gain/(charge)	$ 0.02	$ —	$ (0.01)
Cumulative effect of a change in accounting principle	$ 0.01	$ —	$ —
Net income	$ 2.14	$ 1.33	$ 0.47
Diluted earnings per common share:			
Weighted average shares of common stock outstanding before dilutive effect of certain convertible securities	317,919	297,507	238,706
Income before dilutive effect of certain convertible securities, extraordinary gain/(charge) and cumulative effect of a change in accounting principle	$ 2.02	$ 1.26	$ 0.45
Dilutive effect of certain convertible securities(1)	$ (0.17)	$ (0.06)	$ —
Income before extraordinary gain/(charge) and cumulative effect of a change in accounting principle	$ 1.85	$ 1.20	$ 0.45
Extraordinary gain/(charge)	$ 0.02	$ (0.01)	$ —
Cumulative effect of a change in accounting principle	$ —	$ —	$ —
Net income	$ 1.87	$ 1.19	$ 0.45

(1) Includes the effect of the assumed conversion of certain convertible securities. For the twelve months ended December 31, 2001 and 2000, respectively, the assumed conversion calculation adds 54,183 and 31,746 shares of common stock and $45,898 and $20,841 to the net income results, representing the after tax expense on certain convertible securities avoided upon conversion.

The accompanying notes are an integral part of these consolidated financial statements.

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2001, 2000, and 1999

	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity	Comprehensive Income (Loss)
			(In thousands, except share amounts)			
Balance, December 31, 1998	$177	$ 356,549	$ 68,643	$ (22,659)	$ 402,710	
Issuance of 91,228,316 shares of common stock, net of issuance costs	91	581,339	—	—	581,430	
Tax benefit from stock options exercised and other	—	5,977	—	—	5,977	
Comprehensive income:						
Net income	—	—	106,650	—	106,650	$ 106,650
Foreign currency translation gain, net of tax provision of $2,124	—	—	—	3,322	3,322	3,322
Total comprehensive income	—	—	—	—	—	$ 109,972
Balance, December 31, 1999	268	943,865	175,293	(19,337)	1,100,089	
Issuance of 28,190,682 shares of common stock, net of issuance costs	28	785,900	—	—	785,928	
Issuance of 3,501,532 shares of common stock for acquisitions	4	120,591	—	—	120,595	
Tax benefit from stock options exercised and other	—	46,631	—	—	46,631	
Comprehensive income:						
Net income	—	—	372,602	—	372,602	$ 372,602
Foreign currency translation loss net of tax benefit of $2,278	—	—	—	(3,748)	(3,748)	(3,748)
Total comprehensive income	—	—	—	—	—	$ 368,854
Balance, December 31, 2000	300	1,896,987	547,895	(23,085)	2,422,097	
Issuance of 6,833,497 shares of common stock, net of issuance costs	7	75,680	—	—	75,687	
Issuance of 151,176 shares of common stock for acquisitions	—	7,500	—	—	7,500	
Tax benefit from stock options exercised and other	—	60,669	—	—	60,669	
Comprehensive income:						
Net income	—	—	648,105	—	648,105	$ 648,105
Comprehensive loss on commodity cash flow hedges, net of tax benefit of $87,678 and net of reclassification adjustment	—	—	—	(135,706)	(135,706)	(135,706)
Comprehensive loss on interest rate cash flow hedges, net of tax benefit of $27,170 and net of reclassification adjustment	—	—	—	(45,434)	(45,434)	(45,434)
Comprehensive loss on foreign currency cash flow hedges, net of tax benefit of $1,515 and net of reclassification adjustment	—	—	—	(2,237)	(2,237)	(2,237)
Foreign currency translation loss, net of tax benefit of $14,563	—	—	—	(20,112)	(20,112)	(20,112)
Total comprehensive income	—	—	—	—	—	$ 444,616
Balance, December 31, 2001	$307	$ 2,040,836	$ 1,196,000	$ (226,574)	$3,010,569	

The accompanying notes are an integral part of these consolidated financial statements.

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2001, 2000, and 1999

	2001	2000	1999
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 648,105	$ 372,602	$ 106,650
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	369,870	218,118	139,305
Deferred income taxes, net	20,595	108,481	54,029
Minority interests	9,813	(398)	—
Income from unconsolidated investments in power projects	(8,763)	(24,639)	(36,593)
Distributions from unconsolidated investments in power projects	5,983	29,979	43,318
(Gain) loss on sale of assets	(38,258)	(1,051)	(561)
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable	(207,779)	(515,717)	(38,191)
Notes receivable	(80,700)	(46,066)	(13,919)
Current derivative assets	(763,162)	—	—
Other current assets	(567,484)	(27,728)	(6,924)
Long-term derivative assets	(564,952)	—	—
Other assets	(84,672)	(43,256)	(9,153)
Accounts payable and accrued expenses	481,200	684,970	79,817
Current derivative liabilities	625,339	—	—
Long-term derivative liabilities	822,848	—	—
Other liabilities	72,592	47,255	(3,417)
Other comprehensive income relating to derivatives	(183,377)	—	—
Net cash provided by operating activities	557,198	802,550	314,361
Cash flows from investing activities:			
Purchases of property, plant and equipment	(6,171,737)	(3,184,314)	(1,074,803)
Disposals of property, plant and equipment	49,120	17,321	19,063
Proceeds from sale and leaseback of plant	815,508	642,205	71,236
Acquisitions, net of cash acquired	(1,829,694)	(840,928)	(540,587)
Advances to joint ventures	(149,385)	(141,106)	(48,066)
Decrease (increase) in notes receivable	(12,046)	(184,535)	1,270
Maturities of collateral securities	4,035	6,445	1,850
Project development costs	(143,835)	(53,129)	(30,635)
Decrease (increase) in restricted cash	(62,484)	(15,616)	1,216
Net cash used in investing activities	(7,500,518)	(3,752,657)	(1,599,456)
Cash flows from financing activities:			
Proceeds from issuance of Zero-Coupon Convertible Debentures Due 2021	1,000,000	—	—

	2001	2000	1999
		(In thousands)	
Repurchase of Zero-Coupon Convertible Debentures Due 2021	(122,000)	—	—
Proceeds from notes payable and borrowings under lines of credit	167,363	1,107,267	219,183
Repayments of notes payable and borrowings under lines of credit	(579,892)	(1,117,946)	(129,721)
Borrowings from project financing	3,569,391	1,183,603	155,760
Repayments of project financing	(1,708,710)	(580,111)	(123,386)
Proceeds from issuance of Convertible Senior Notes Due 2006	1,100,000	—	—
Proceeds from issuance of senior notes	4,596,039	1,000,000	600,000
Repurchase of senior notes	(105,000)	—	—
Proceeds from Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts	—	877,500	276,000
Proceeds from equity offerings, net of issuance costs	—	773,249	597,368
Proceeds from issuance of common stock	75,424	14,767	6,192
Write-off of deferred financing costs	—	2,031	1,943
Financing costs	(154,582)	(58,942)	(65,405)
Other	38,292	(4,605)	—
Net cash provided by financing activities	7,876,325	3,196,813	1,537,934
Effect of exchange rate changes on cash and cash equivalents	(3,665)	—	—
Net increase in cash and cash equivalents	929,340	246,706	252,839
Cash and cash equivalents, beginning of year	596,077	349,371	96,532
Cash and cash equivalents, end of year	$ 1,525,417	$ 596,077	$ 349,371
Cash paid during the year for:			
Interest, net of amounts capitalized	$ 27,010	$ 20,752	$ 78,968
Income taxes	$ 271,973	$ 144,406	$ 17,066

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the Years Ended December 31, 2001, 2000, and 1999

1. Organization and Operations of the Company

Calpine Corporation ("Calpine"), a Delaware corporation, and subsidiaries (collectively, "the Company") is engaged in the generation of electricity in the United States, Canada and the United Kingdom. The Company is involved in the development, acquisition, ownership and operation of power generation facilities and the sale of electricity and its by-product, thermal energy, primarily in the form of steam. The Company has ownership interests in and operates gas-fired power generation and cogeneration facilities, gas fields, gathering systems and gas pipelines, geothermal steam fields and geothermal power generation facilities in the United States. In Canada, the Company has power facilities and oil and gas operations. In the United Kingdom, the Company has a gas-fired power cogeneration facility. Each of the generation facilities produces and markets electricity for sale to utilities and other third party purchasers. Thermal energy produced by the gas-fired cogeneration facilities is primarily sold to governmental and industrial users. Gas produced and not physically delivered to the Company's generating plants is sold to third parties.

2. Summary of Significant Accounting Policies

Principles of Consolidation — The accompanying consolidated financial statements include accounts of the Company. Wholly owned and majority-owned subsidiaries are consolidated. Less-than-majority-owned subsidiaries and subsidiaries for which control is deemed to be temporary, are accounted for using the equity method. For equity method investments, the Company's share of income is calculated according to the Company's equity ownership or according to the terms of the appropriate partnership agreement (see Note 6). All intercompany accounts and transactions are eliminated in consolidation.

On April 19, 2001, Calpine acquired 100% of the outstanding shares and interests of Encal Energy Ltd. ("Encal"). Encal is a Calgary, Alberta-based natural gas and petroleum exploration and development company. As a result of the merger, the Company issued approximately 16.6 million common shares for all of the outstanding Encal capital stock and options. The merger was accounted for as a pooling-of-interests, and the consolidated financial statements have been prepared to give retroactive effect to the merger.

Encal operated under the same fiscal year end as Calpine, and accordingly, Encal's balance sheets, as of December 31, 2000 and 1999, and the statements of operations, shareholders' equity and cash flows for each of the two fiscal years in the period ended December 31, 2000, have been combined with the Company's consolidated financial statements. The results of operations previously reported by the separate companies and the combined amounts presented in the consolidated financial statements are summarized below.

	Years Ended December 31,	
	2000	1999
	(In thousands)	
Revenues:		
Calpine	$2,282,793	$ 847,735
Encal	264,308	135,749
Combined revenues	$2,547,101	$ 983,484
Net Income:		
Calpine	$ 323,452	$ 95,093
Encal	49,150	11,557
Combined net income	$ 372,602	$ 106,650
Stockholders' Equity:		
Calpine	$2,236,774	$ 964,632
Encal	185,323	135,457
Combined stockholders' equity	$2,422,097	$1,100,089

Use of Estimates in Preparation of Financial Statements — The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. Actual results could differ from those estimates. The most significant estimates with regard to these financial statements relate to future development costs, useful lives of the generation facilities, and depletion, depreciation and impairment of natural gas and petroleum property and equipment.

Foreign Currency Translation — Assets and liabilities of non-U.S. subsidiaries that operate in a local currency environment are translated to U.S. dollars at exchange rates in effect at the balance sheet date with the resulting translation adjustments recorded in other comprehensive income. Income and expense accounts are translated at average exchange rates during the year.

Fair Value of Financial Instruments — The carrying value of cash, accounts receivable, marketable securities, accounts and other payables approximate their respective fair values due to their short maturities. See Note 12 for disclosures regarding the fair value of the senior notes.

Cash and Cash Equivalents — The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents. The carrying amount of these instruments approximates fair value because of their short maturity.

The Company has certain project debt agreements which temporarily limit the use of certain cash balances to construction spending, operating and maintenance costs, lease payments, interest and debt principal payments for specific projects. At December 31, 2001, $269.9 million of the cash balance was subject to such project debt agreements. When restrictions are ongoing, we classify such balances as "restricted cash" (see below).

Inventories — The Company's inventories primarily include spare parts and stored gas. Operating supplies are valued at the lower of cost or market. Cost for large replacement parts estimated to be used within one year is determined using the specific identification method. For the remaining supplies and spare parts, cost is generally determined using the weighted average cost method. Stored gas is valued at the lower of cost or market.

Margin Deposits — As of December 31, 2001, in order to satisfy the credit requirements of trading counterparties, the Company's Calpine Energy Services, LP ("CES") subsidiary had deposited $345.5 million in cash as margin deposits. No such deposits were required as of December 31, 2000.

Property, Plant and Equipment, Net — See Note 3 for a discussion of the Company's accounting policies for its property, plant and equipment.

Project Development Costs — The Company capitalizes project development costs once it is determined that it is probable that such costs will be realized through the ultimate construction of a power plant. These costs include professional services, salaries, permits and other costs directly related to the development of a new project. Upon commencement of construction, these costs are transferred to construction in progress, a component of property, plant and equipment. Upon the start-up of plant operations, these construction costs are amortized as a component of the total cost of the plant over the estimated useful life of the project. Capitalized project costs are charged to expense if the Company determines that the project is impaired. Outside services and other third party costs are capitalized for acquisition projects.

Restricted Cash — The Company is required to maintain cash balances that are restricted by provisions of its debt agreements, lease agreements and regulatory agencies. When the restrictions on these funds are ongoing during the period of financing, we classify the balances as restricted cash. These amounts are held by depository banks in order to comply with contractual provisions requiring reserves for payments such as debt service, rent service, and major maintenance. Restricted cash is invested in accounts earning market rates; therefore, the carrying value approximates fair value. Such cash is excluded from cash and cash equivalents for the purposes of the consolidated statements of cash flows.

Deferred Financing Costs — The deferred financing costs related to the Company's senior notes and the Convertible Senior Notes Due 2006 are amortized over the life of the related debt, ranging from 5 to 10 years, using the straight-line method which approximates the effective interest rate method (See Note 12). The deferred financing costs associated with the two Calpine Construction Finance Company facilities are amortized over the 4-year facility lives using the straight-line method (See Note 10). The deferred financing costs related to the Zero-Coupon Debentures Due 2021 are amortized over 1 year due to the put that can be exercised by the holders in 2002. Costs incurred in connection with obtaining other financing are deferred and amortized over the life of the related debt.

Long-Lived Assets — In accordance with Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of," the Company evaluates the impairment of long-lived assets, including goodwill, based on the projection of undiscounted cash flows whenever events or changes in circumstances indicate that the carrying amounts of such assets may not be recoverable. In the event such cash flows are not expected to be sufficient to recover the recorded value of the assets, the assets are written down to their estimated fair values.

Concentrations of Credit Risk — Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of cash, accounts receivable, notes receivable, and commodity contracts. The Company's cash accounts are generally held in FDIC insured banks. The Company's accounts and notes receivable are concentrated within entities engaged in the energy industry, mainly within the United States (see Note 7 and 18). The Company generally does not require collateral for accounts receivable from end-user customers, but evaluates the net accounts receivable, accounts payable, and fair value of commodity contracts with trading companies and may require security deposits or letters of credit to be posted if exposure reaches a certain level.

Trust Preferred Securities — The Company's trust preferred securities are accounted for as a minority interest in the balance sheet and reflected as "Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts." The distributions are reflected on the income statement as "distributions on trust preferred securities." Financing costs related to these issuances are netted with the principal amounts and are accreted over the securities' 30-year maturity using the straight-line method (See Note 14).

Revenue Recognition — The Company is primarily an electric generation company, operating a portfolio of mostly wholly owned plants but also some plants in which its ownership interest is 50% or less and which are accounted for under the equity method. In conjunction with its electric generation business, the Company also produces, as a by-product, thermal energy for sale to customers, principally steam hosts at its cogeneration sites. In addition, the Company acquires and produces natural gas for its own consumption and sells the balance and small amounts of oil to third parties. To protect and enhance the profit potential of its electric generation plants, the Company, through its subsidiary, CES, enters into electric and gas hedging, balancing, optimization, and trading transactions in which purchased electricity and gas is resold to third parties. CES generally acts as a principal, takes title to the commodities purchased for resale, and assumes the risks and rewards of ownership. Therefore, in accordance with Staff Accounting Bulletin No. 101, "Revenue Recognition in Financial Statements" and the Emerging Issues Task Force ("EITF") Issue No. 99-19, "Reporting Revenue Gross as a Principal Versus Net as an Agent," CES recognizes revenue on a gross basis, except in the case of financial swap transactions, in which case the net gain or loss from the financial swap is recorded in income when the effects of the risks being managed are recognized. Managed risks typically include sales to third parties of natural gas produced, purchases of natural gas to fuel power plants, and sales of generated electricity. The Company, through Power Systems Mfg., LLC ("PSM"), designs and manufactures certain spare parts for gas turbines. The Company also generates small amounts of revenue by occasionally loaning funds to power projects, by providing operation and maintenance ("O&M") services to unconsolidated power plants, and by performing engineering services for data center and other facilities requiring highly reliable power. Further details of the Company's revenue recognition policy for each type of revenue transaction are provided below:

Electric Generation and Marketing Revenue — This includes electricity and steam revenue, sales of purchased power and mark-to-market gains and losses from electric power derivatives.

Electrical energy revenue is recognized upon transmission to the customer, and capacity and ancillary revenue is recognized when contractually earned. In accordance with EITF Issue No. 91-6, revenues from contracts entered into or acquired since May 1992 are recognized at the lesser of amounts billable under the contract or amounts recognizable at an average rate over the term of the contract. The Company's power sales agreements related to Calpine Geysers Company ("CGC") were entered into prior to May 1992. Had the Company applied the methodology described above to the CGC power sales agreements, the revenues recorded for the years ended December 31, 2001, 2000, and 1999 would have been approximately $133,000 lower, $8.1 million lower, and $24.2 million higher, respectively. Net gains or losses from qualified hedges of electricity positions are included in electricity and steam revenue.

Oil and Gas Production and Marketing Revenue — This includes sales to third parties of oil, gas and related products that are produced by the Company's Calpine Natural Gas and Calpine Canada Natural Gas subsidiaries and also sales of purchased gas. Oil and gas revenues are recognized pursuant to the sales method.

Income from Unconsolidated Investments in Power Projects — The Company uses the equity method to recognize as revenue its pro rata share of the net income or loss of the unconsolidated investment until such time, if applicable, that the Company's investment is reduced to zero, at which time equity income is generally recognized only upon receipt of cash distributions from the investee.

Other Revenue — This includes O&M contract revenue, interest income on loans to power projects, PSM revenue from sales to third parties, engineering revenue and miscellaneous revenue.

Purchased Power and Gas Sales and Expense — The Company records the cost of gas consumed in its power plants as fuel expense, while gas purchased from third parties for hedging, balancing, and optimization activities is recorded as the cost of gas purchased and resold, a component of oil and gas production and marketing expense. The Company records the actual revenue received from third parties as sales of purchased gas, a component of oil and gas production and marketing revenue.

The cost of power purchased from third parties, for hedging, balancing, and optimization activities, along with the subsequent settlement of contracts that have been previously recorded in results of operations as mark-to-market gains or losses, is recorded as purchased power expense, a component of electric generation and marketing expense. The Company markets on a system basis both power generated by its plants in excess of amounts under direct contract between the plant and a third party, and power purchased from third parties.

Insurance Program — The CPN Insurance Corporation, a Hawaii-based, wholly owned captive insurance subsidiary, charges the Company competitive premium rates to insure workers' compensation, auto and general liability and all risk property including business interruption. Accruals for claims under the captive insurance program pertaining to property including business interruption claims are recorded on a claims-incurred basis. Accruals for casualty claims under the captive insurance program are recorded on a monthly basis, and are based upon the estimate of the total cost of claims incurred during the policy period.

Derivative Instruments — Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities — Deferral of the Effective Date of FASB Statement No. 133 — an Amendment of FASB Statement No. 133" and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities — an Amendment of FASB Statement No. 133" established accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. The statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Based on the nature of the Company's derivative instruments currently outstanding and the historical volatility of commodity prices, the Company expects that SFAS No. 133 could increase volatility in the Company's earnings and other comprehensive income for future periods.

SFAS No. 133 includes special accounting for cash flow and fair value hedges. SFAS No. 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings. SFAS No. 133 provides that the changes in fair value of derivatives designated as fair value hedges and the corresponding changes in the fair value of the hedged risk attributable to a recognized asset, liability, or unrecognized firm commitment be recorded in earnings. If the fair value hedge is effective, the amounts recorded will offset in earnings.

SFAS No. 133 requires that as of the date of initial adoption, the difference between the fair value of derivative instruments and the previous carrying amount of these derivatives be recorded in net income or other comprehensive income, as appropriate, as the cumulative effect of a change in accounting principle. Upon adoption of SFAS No. 133, the Company recorded cumulative effects of a change in accounting principle of $1.0 million (net of a $0.7 million tax provision) to net income and $39.8 million (net of a $25.7 million tax provision) to other comprehensive income.

New Accounting Pronouncements — In June 2001 the FASB issued SFAS No. 141, "Business Combinations", which supersedes Accounting Principles Board ("APB") Opinion No. 16, "Business Combinations" and SFAS No. 38, "Accounting for Preacquisition Contingencies of Purchased Enterprises". SFAS No. 141 eliminates the pooling-of-interests method of accounting for business combinations and modifies the recognition of intangible assets and disclosure requirements. The elimination of the pooling-of-interests method is effective for transactions initiated after June 30, 2001. The remaining provisions of SFAS No. 141 are effective for transactions accounted for using the purchase method that are completed after June 30, 2001. The Company does not believe that SFAS No. 141 will have a material effect on its consolidated financial statements.

In June 2001 the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets", which supersedes APB Opinion No. 17, "Intangible Assets". SFAS No. 142 eliminates the current requirement to amortize goodwill and indefinite-lived intangible assets, extends the allowable useful lives of certain intangible assets, and requires impairment testing and recognition for goodwill and intangible assets. SFAS No. 142 will apply to goodwill and other intangible assets arising from transactions completed both before and after its effective date. The provisions of SFAS No. 142 are required to be applied starting with fiscal years beginning after December 15, 2001. As of December 31, 2001, the Company's unamortized goodwill and other intangible assets balance was $29.4 million, and was being amortized over periods ranging from 10 to 20 years. As a result of SFAS No. 142, the Company currently estimates that the elimination of goodwill and other intangible assets amortization will result in pre-tax savings of $1.8 million in 2002. The Company has not yet finalized the financial statement impact of SFAS No. 142.

In June 2001 the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations", which amends SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies". SFAS No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. SFAS No. 143 is effective for financial statements issued for fiscal years beginning after June 15, 2002. The Company does not believe that SFAS No. 143 will have a material effect on its consolidated financial statements.

In August 2001 the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", which supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of", and the accounting and reporting provisions of APB Opinion No. 30, "Reporting the Results of Operations — Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions", for the disposal of a segment of a business (as previously defined in that APB Opinion). SFAS No. 144 establishes a single accounting model, based on the framework established in SFAS No. 121, for long-lived assets to be disposed of by sale. SFAS No. 144 also resolves several significant implementation issues related to SFAS No. 121, such as eliminating the requirement to allocate goodwill to long-lived assets to be tested for impairment and establishing criteria to define whether a long-lived asset is held for sale. SFAS No. 144 is effective for financial statements issued for fiscal years beginning after December 15, 2001. The Company does not believe that SFAS No. 144 will have a material effect on its consolidated financial statements.

Reclassifications — Certain prior years' amounts in the Consolidated Financial Statements have been reclassified to conform to the 2001 presentation.

3. Property, Plant and Equipment, Net, and Capitalized Interest

As of December 31, 2001 and 2000, the components of property, plant and equipment, are stated at cost less accumulated depreciation, depletion, and amortization as follows (in thousands):

	2001	2000
Buildings, machinery, and equipment	$ 4,556,389	$1,951,250
Oil and gas properties, including pipelines	2,283,344	1,441,175
Geothermal properties	374,123	334,585
Power sales agreements	143,330	162,086
Fuel supply and fuel management contracts	140,221	129,999
Other	254,563	145,877
	7,751,970	4,164,972
Less: accumulated depreciation, depletion, and amortization	(949,446)	(614,816)
	6,802,524	3,550,156
Land	80,506	12,578
Construction in progress	8,501,960	4,416,426
Property, plant and equipment, net	$15,384,990	$7,979,160

Buildings, Machinery, and Equipment — This component includes cogeneration plants and related equipment. Depreciation is recorded utilizing the straight-line method over the estimated original useful life of up to 35 years, exclusive of the estimated salvage value, typically 10%. The Company defers the costs for major gas turbine generator refurbishment and amortizes them over 3 to 6 years. Additionally, the Company expenses certain annual planned maintenance.

Oil and gas properties — The Company follows the successful efforts method of accounting for oil and natural gas activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Proved oil and gas properties are reviewed when circumstances suggest the need for such a review and, if required, the proved properties are written down to their estimated fair value. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Estimated fair value includes the estimated present value of all reasonably expected production based on current prices and costs at the time of review. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs are expensed as incurred. Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated as successful. The provision for depreciation, depletion, and amortization is based on the capitalized costs as determined above, plus future abandonment costs, and is on a cost center-by-cost center basis using the units of production method with lease acquisition costs amortized over total proved reserves and other costs amortized over proved developed reserves.

Geothermal Properties — The Company capitalizes costs incurred in connection with the development of geothermal properties, including costs of drilling wells and overhead directly related to development activities, together with the costs of production equipment, the related facilities and the operating power plants at such time as management determines that it is probable the property will be developed on an economically viable basis and that costs will be recovered from operations. Proceeds from the sale of geothermal properties are applied against capitalized costs, with no gain or loss recognized.

Geothermal costs, including an estimate of future costs to be incurred, costs to optimize the productivity of the assets, and the estimated costs to dismantle, are amortized by the units of production method based on the estimated total productive output over the estimated useful lives of the related steam fields. Depreciation of the buildings and roads is computed using the straight-line method over their estimated useful lives. It is reasonably possible that the estimate of useful lives, total unit-of-production or total capital costs to be amortized using the units-of-production method could differ materially in the near term from the amounts assumed in arriving at current depreciation expense. These estimates are affected by such factors as the ability of the Company to continue selling electricity to customers at estimated prices, changes in prices of alternative sources of energy such as hydro-generation and gas, and changes in the regulatory environment. Geothermal steam turbine generator refurbishments are expensed as incurred.

Power Sales Agreements, Fuel Supply Contracts, and Fuel Management Contracts — These contracts are acquired as a component of certain business combinations. The amount recorded on the balance sheet represents the value on the date of acquisition of the difference between the contract pricing and other terms and the market straight-line pricing and other terms on that date. The value of the above-market or below-market pricing and other terms is generally amortized over the remaining life of the agreement or contract while the value associated with certain contracts is amortized volumetrically. These contracts have remaining lives up to 35 years.

When assets are disposed of, the cost and related accumulated depreciation are removed from the accounts, and the resulting gains or losses are included in results of operations.

Construction in Progress — Construction in progress is primarily attributable to gas-fired power projects under construction including prepayments on gas turbine generators. Upon commencement of plant operation, these costs are transferred to the applicable above property category as appropriate.

Capitalized Interest — The Company capitalizes interest on capital invested in projects during the advanced stages of development and the construction period in accordance with SFAS No. 34, "Capitalization of Interest Cost," as amended by SFAS No. 58, "Capitalization of Interest Cost in Financial Statements That Include Investments Accounted for by the Equity Method (an Amendment of FASB Statement No. 34)." The Company's qualifying assets include construction in progress, certain oil and gas properties under development, construction costs related to unconsolidated investments in power projects under construction, and advanced stage development costs. For the years ended December 31, 2001 and 2000, the total amount of interest capitalized was $498.7 million and $207.0 million, including $136.0 million and $36.0 million, respectively, of interest incurred on funds borrowed for specific construction projects and $362.7 million and $171.0 million, respectively of interest incurred on general corporate funds used for construction. Upon commencement of plant operation, capitalized interest, as a component of the total cost of the plant, is amortized over the estimated useful life of the plant. The increase in the amount of interest capitalized during the year ended December 31, 2001, reflects the significant increase in the Company's power plant construction program.

In accordance with SFAS No. 34, the Company determines which debt instruments best represent a reasonable measure of the cost of financing construction assets in terms of interest cost incurred that otherwise could have been avoided. These debt instruments and associated interest cost are included in the calculation of the weighted average interest rate used for capitalizing interest on general funds. The primary debt instruments included in the rate calculation for 2000 and 2001 are the Senior Notes and the $400.0 million corporate revolver.

4. Acquisitions

Western Transaction

On February 4, 2000, the Company acquired 100% of the stock of Western Gas Resources California ("Western") from Western Gas Resources, Inc. for $14.9 million. Western's assets include the 130-mile Steelhead natural gas pipeline and the remaining interest in the Sacramento River Gas System natural gas pipeline, now 100% owned by Calpine.

Hidalgo Transaction

On March 30, 2000, the Company purchased a 78.5% interest in the 502-megawatt Hidalgo Energy Center ("Hidalgo") which was under construction in Edinburg, Texas, from Duke Energy North America for $235.0 million. The purchase included a cash payment of $134.0 million and the assumption of a $101.0 million capital lease obligation. The Hidalgo Energy Center sells power into the Electric Reliability Council of Texas' ("ERCOT") wholesale market. Construction of the facility began in February 1999 and commercial operation was achieved in June 2000.

KIAC and Stony Brook Transaction

On May 31, 2000, Calpine acquired the remaining 50% interests in the 105-megawatt Kennedy International Airport Power Plant ("KIAC") in Queens, New York and the 40-megawatt Stony Brook Power Plant located at the State University of New York at Stony Brook on Long Island from Statoil Energy, Inc. The Company paid approximately $71.0 million in cash and assumed a capital lease obligation relating to the Stony Brook Power Plant and an operating lease obligation relating to the KIAC Power Plant. The Company initially acquired a 50% interest in both facilities in December 1997.

Freestone Transaction

On June 15, 2000, the Company announced that it had acquired the Freestone Energy Center ("Freestone") from Energy Corporation. Freestone is a 1,052-megawatt natural gas-fired energy center under development in Freestone County, Texas. The Company paid approximately $61.0 million in cash and assumed certain liabilities. This represented payment for the land and development rights for the Freestone Energy Center, previous progress payments made for four General Electric gas turbines, two steam turbines and related equipment, and development expenditures.

Auburndale Transaction

On June 30, 2000, the Company acquired from Edison Mission Energy the remaining 50% ownership interest in a 153-megawatt natural gas-fired, combined-cycle cogeneration facility located in Auburndale, Fla. The Company paid approximately $22.0 million in cash and assumed certain liabilities, including project level debt. The Company acquired an initial 50% ownership interest in the Auburndale Power Plant in October 1997.

Natural Gas Reserves Transactions

On July 5, 2000, the Company completed three acquisitions of natural gas reserves for $206.5 million, including the acquisition of Calgary-based Quintana Minerals Canada Corp. ("QMCC"), three fields in the Gulf of Mexico and natural gas assets in the Piceance Basin, Colorado and onshore Gulf Coast. The Company subsequently changed QMCC's name to Calpine Canada Natural Gas, Ltd. ("CCNG").

Oneta Transaction

On July 20, 2000, the Company completed the acquisition of the 1,138-megawatt natural gas-fired Oneta Energy Center, ("Oneta") in Coseta, Oklahoma, from Panda Energy International, Inc.

Agnews Transaction

On August 16, 2000, the Company acquired the remaining 80% interest in the Agnews Power Plant, a 29-megawatt natural gas-fired, combined-cycle facility located in San Jose, California from GATX Capital Corporation for a total purchase price of $4.9 million and the assumption of a capital lease obligation. The Company first acquired a 20% equity interest in the Agnews Power Plant in 1990.

Aidlin Transaction

On August 31, 2000, the Company acquired the remaining 45% equity interest in the Aidlin Power Plant from an affiliate of Sumitomo Corporation for a total purchase price of $6.4 million. The Company initially acquired a 5% equity interest in the Aidlin Power Plant in 1989, representing Calpine's first megawatt of generation. That interest was increased to 55% with the acquisition of two other partners' interests in 1999. Located in The Geysers region of northern California, Aidlin is a 20-megawatt power plant.

SkyGen Energy Transaction

On October 12, 2000, the Company completed the acquisition of Northbrook, Illinois-based SkyGen Energy LLC ("SkyGen") from Michael Polsky and Wisvest Corporation ("Wisvest"), an affiliate of Wisconsin Energy Corp., for a total purchase price of $359.1 million. The purchase price included cash payments of $294.2 million and 2,117,742 shares of Calpine common stock (which were valued in the aggregate at $64.9 million at signing of the letter of intent).

TriGas Transaction

On November 15, 2000, the Company acquired TriGas Exploration Inc. ("TriGas"), a Calgary-based oil and gas company, for a total purchase price of $101.1 million. The purchase price included cash payments of $79.6 million, as well as assumed net indebtedness of $21.5 million. The acquisition provided Calpine with natural gas reserves to fuel its Calgary Energy Centre, and a 26.6% working interest in the East Crossfield Gas Plant, a majority interest in 63 miles of pipeline that conducts the gas to two nearby gas-fired power generation facilities, and a significant undeveloped land base with development potential.

PSM Transaction

On December 13, 2000, the Company completed the acquisition of Boca Raton, Florida-based PSM for a total purchase price of $16.3 million. The purchase price included cash payments of $5.6 million and 281,189 shares of Calpine common stock (which were valued in the aggregate at $10.7 million at the closing of the agreement). Additionally, the agreement provides for five equal installments of cash payments, totaling $26.7 million, beginning in January 2002, contingent upon future PSM performance. PSM specializes in the design and manufacturing of turbine hot section blades, vanes, combustors and low emissions combustion components.

EMI Transaction

On December 15, 2000, the Company completed the acquisition of strategic power assets from Dartmouth, Massachusetts-based Energy Management, Inc. ("EMI") for a total purchase price of $145.0 million. The purchase price included cash payments of $100.0 million and 1,102,601 shares of Calpine common stock (which were valued in the aggregate at $45.0 million at the closing of the agreement). Under the terms of the agreement, the Company acquired the remaining interest in three recently constructed combined-cycle power generating facilities located in Dighton, Massachusetts, Tiverton, Rhode Island, and Rumford, Maine, as well as Calpine-EMI Marketing LLC, a joint marketing venture between Calpine and EMI.

The following mergers and acquisitions were consummated during the year ended December 31, 2001. All business combinations made during 2001 were accounted for as purchases, with the exception of the Encal pooling-of-interests transaction.

WRMS Transaction

On April 3, 2001, the Company acquired all of the common shares of WRMS Engineering, Inc. ("WRMS"), a California-based engineering and architectural firm, through a stock-for-stock exchange in which WRMS shareholders received a total of 151,176 shares of Calpine common stock. The aggregate value of the transaction was approximately $7.8 million, including the assumed indebtedness of WRMS.

Encal Transaction

On April 19, 2001, the Company completed its merger with Encal, a Calgary, Alberta-based natural gas and petroleum exploration and development company. Encal shareholders received, in exchange for each share of Encal common stock, 0.1493 shares of Calpine common equivalent shares (called "exchangeable shares") of the Company's subsidiary, Calpine Canada Holdings Ltd. A total of 16,603,633 exchangeable shares were issued to Encal shareholders in exchange for all of the outstanding shares of Encal common stock. Each exchangeable share is exchangeable for one share of Calpine common stock. The aggregate value of the transaction was approximately US$1.1 billion, including the assumed indebtedness of Encal. The transaction was accounted for as a pooling-of-interests and, accordingly, all historical amounts reflected in the consolidated financial statements have been restated to reflect the transaction in accordance with APB Opinion

No. 16, "Business Combinations" ("APB 16"). Encal operated under the same fiscal year end as Calpine, and accordingly, Encal's balance sheet as of December 31, 2000, and the statements of operations, shareholders' equity and cash flows for each of the two fiscal years in the period ended December 31, 2000, have been combined with the Company's consolidated financial statements. The Company incurred $41.6 million in nonrecurring merger costs for this transaction. Upon completion of the acquisition, we gained approximately 664 billion cubic feet equivalent of proved natural gas reserves, net of royalties. This transaction also provides access to firm gas transportation capacity from western Canada to California and the eastern U.S., and an accomplished management team capable of leading our business expansion in Canada. In addition, Encal had proved undeveloped acreage totaling approximately 1.2 million acres.

Saltend Transaction

On August 24, 2001, the Company acquired and assumed operations of the Saltend Energy Centre ("Saltend"), a 1,200-megawatt natural gas-fired power plant located at Saltend near Hull, Yorkshire, England. The Company purchased the cogeneration facility from an affiliate of Entergy Corporation for £565.0 million (US$818.1 million at exchange rates at the closing of the acquisition). Saltend began commercial operation in November 2000 and is one of the largest natural gas-fired electric power generating facilities in England.

Hog Bayou and Pine Bluff Transactions

On September 12, 2001, the Company purchased the remaining 33.3% interests in the 247-megawatt Hog Bayou Energy Center ("Hog Bayou") and the 213-megawatt Pine Bluff Energy Center ("Pine Bluff") from Houston, Texas-based Intergen (North America), Inc. for approximately $9.6 million.

Westcoast Transaction

On September 20, 2001, the Company's wholly owned subsidiary, Canada Power Holdings Ltd., acquired and assumed operations of two Canadian power generating facilities from British Columbia-based Westcoast Energy Inc. ("Westcoast") for C$333.1 million (US$212.1 million at exchange rates at the closing of the acquisition). The Company acquired a 100% interest in the Island Cogeneration facility ("Island"), a 250-megawatt natural gas-fired electric generating facility in the commissioning phase of construction and located near Campbell River, British Columbia on Vancouver Island. The Company also acquired a 50% interest in the 50-megawatt Whitby Cogeneration facility ("Whitby") located in Whitby, Ontario.

California Energy General Corporation and CE Newburry, Inc. Transaction

On October 16, 2001, the Company acquired California Energy General Corporation ("California Energy") and CE Newburry, Inc. ("CE Newburry") from MidAmerican Energy Holdings Company for $22.0 million. The transaction includes the companies' geothermal resource assets, contracts, leases and development opportunities associated with the Glass Mountain Known Geothermal Resource Area ("Glass Mountain KGRA") located in Siskiyou County, California, approximately 30 miles south of the Oregon border. These purchases are directly related to the Company's plans to develop the 49.5-megawatt Fourmile Hill Geothermal Project located in the Glass Mountain KGRA.

Michael Petroleum Transaction

On October 22, 2001, the Company completed the acquisition of 100% of the voting stock of Michael Petroleum Corporation ("Michael"), a natural gas exploration and production company, for cash of $315.8 million, plus the assumption of $54.5 million of debt. The acquired assets consisted of approximately 531 wells, producing approximately 33.5 net mmcfe/d of which 90 percent is gas, and developed and non-developed acreage totaling approximately 82,590 net acres at year end.

Highland Transaction

On November 5, 2001, the Company acquired Highland Energy Company ("Highland") from Entergy Power Gas Operations Corporation and Louis Morrison III for $4.5 million. Highland has an established service that assists small and medium-size independent producers in the aggregation of their natural gas, crude oil and natural gas liquids.

Delta, Metcalf and Russell City Transactions

On November 6, 2001, the Company acquired Bechtel Enterprises Holdings, Inc.'s 50% interest in the 874-megawatt Delta Energy Center ("Delta"), the 600-megawatt Metcalf Energy Center ("Metcalf") and the 600-megawatt Russell City Energy Center ("Russell City") for approximately $154.0 million and the assumption of approximately $141.0 million of debt. As a result of this acquisition, the Company now owns a 100% interest in all three facilities.

The initial purchase price allocation for all material business combinations initiated after June 30, 2001, is shown below. As of December 31, 2001, the Company had not finalized the purchase price allocation for Westcoast or Saltend. The Company is currently in negotiations to determine the proper value of certain tax pools obtained as part of the Westcoast transaction, and expects a settlement to be reached during 2002. Additionally, based on the terms of the purchase agreement, a working capital adjustment related to the Saltend acquisition had not been finalized.

	Saltend	Michael Petroleum	Westcoast
Current assets	$ 27,363	$ 5,970	$ 4,468
Property, plant and equipment	906,801	535,007	212,902
Other assets	1,478	—	—
Investments in power plants	—	—	25,907
Current liabilities	(21,900)	(16,852)	(6,802)
Derivative liability	—	(1,862)	—
Notes payable	—	(54,500)	—
Deferred tax liabilities, net	(95,671)	(151,946)	(24,408)
Net purchase price	$818,071	$ 315,817	$212,067

Pro Forma Effects of Acquisitions

Acquired subsidiaries are consolidated upon acquisition. The table below reflects unaudited pro forma combined results of the Company, Western, Hidalgo, KIAC, Stony Brook, Freestone, Auburndale, QMCC, Oneta, Agnews, Aidlin, SkyGen, TriGas, PSM, EMI, WRMS, Bayless, Saltend, Hog Bayou, Pine Bluff, Island, Whitby, California Energy, CE Newburry, Michael, Highland, Delta, Metcalf, and Russell City as if the acquisitions had taken place at the beginning of fiscal years 2001 and 2000 (in thousands, except per share amounts):

	2001	2000
Total revenue	$7,783,055	$2,853,811
Income before extraordinary charge	$ 640,102	$ 397,120
Net income	$ 647,149	$ 395,885
Net income per basic share	$ 2.13	$ 1.41
Net income per diluted share	$ 1.86	$ 1.27

In management's opinion, these unaudited pro forma amounts are not necessarily indicative of what the actual combined results of operations might have been if the acquisitions had been effective at the beginning of fiscal years 2001 and 2000. In addition, they are not intended to be a projection of future results and do not reflect all the synergies that might be achieved from combined operations.

5. Sale and Leaseback Transactions

In 2001 and 2000, the Company completed the following sale-leaseback transactions, which resulted in operating leases. All counterparties in the sale-leaseback transactions are unrelated to the Company. In connection with these transactions, the Company recorded deferred gains (losses) which are being amortized as a reduction of (addition to) operating lease expense over the respective remaining lives of the leases.

On September 1, 2000, the Company completed a leveraged lease financing transaction to provide the term financing for both Phase I and Phase II of the Pasadena, Texas Cogeneration project. Under the terms of the lease, the Company received $400.0 million in gross proceeds and recorded a deferred gain of approximately $65.0 million.

On December 19, 2000, the Company completed a leveraged lease financing transaction for the Tiverton and Rumford facilities raising $466.7 million in gross proceeds, resulting in a deferred gain of $1.7 million. In connection with this transaction, Calpine Corporation provided a guarantee for the obligations under the leases but did not guarantee the lessors' debt. In connection with this transaction, the Company issued letters of credit to support the obligation to make rent payments to the lessor. At December 31, 2001, and 2000, $57.2 million, and $52.1 million in letters of credit were outstanding, respectively.

On December 22, 2000, the Company completed a leveraged lease financing transaction of its West Ford Flat and Bear Canyon projects. Under the terms of the agreement, the facilities were incorporated into the Company's geothermal lease facility, which the Company originally entered into on May 7, 1999. The Company received $81.0 million in gross proceeds and recorded a deferred loss of approximately $8.1 million.

On September 30, 2001, the Company completed a leveraged lease financing transaction of its Aidlin project. Under the terms of the agreement, the facility was incorporated into the Company's geothermal lease facility, which the Company originally entered into on May 7, 1999. The Company received $29.0 million in gross proceeds and recorded a deferred gain of approximately $6.8 million.

On October 18, 2001, the Company completed leveraged lease financing transactions for the South Point, Broad River and RockGen facilities raising $800.0 million in gross proceeds, resulting in a deferred gain of approximately $22.8 million. In connection with these transactions, Calpine Corporation provided a guarantee for the obligations of its subsidiaries under the leases but did not guarantee the lessors' debt. The lessors issued lessor notes with an aggregate principal amount of $654.5 million, which was funded by the proceeds from the issuance of pass through certificates. In effect, the pass through certificates evidence the debt component of these sale/leaseback transactions. The pass through certificates were issued in two tranches: the first, consisting of $454.5 million in aggregate principal amount of 8.4% Series A Certificates due May 30, 2012, and the second, consisting of $200 million in aggregate principal amount of 9.825% Series B Certificates due May 30, 2019.

The transactions involving Tiverton, Rumford, South Point, Broad River, and RockGen utilize special-purpose entities formed by the lessor with the sole purpose of owning a power generation facility. The Company is not the owner of the SPE nor does the Company have any direct or indirect ownership interest in each respective SPE; therefore the SPEs are appropriately not consolidated as subsidiaries of the Company.

6. Investments in Power Projects

Investments, which are accounted for under the equity method, are as follows (in thousands):

	Ownership Interest as of December 31, 2001	December 31, 2001	December 31, 2000
Sumas Power Plant	(1)	$ —	$ —
Acadia Power Plant	50.0%	223,452	108,529
Grays Ferry Power Plant	40.0%	31,605	30,257
Aries Power Plant	50.0%	26,133	22,350
Gordonsville Power Plant	50.0%	21,687	18,060
Lockport Power Plant	11.4%	15,919	14,722
Bayonne Power Plant(2)	7.5%	—	8,385
Whitby Cogeneration	50.0%	25,848	—
Endūr(3)	23.0%	25,421	—
Other	—	8,549	3,318
Total investments in power projects		$378,614	$205,621

(1) On December 31, 1998, the Partnership agreement governing Sumas Cogeneration Company, L.P. ("Sumas") was amended changing the distributions schedule for the Company from the previously amended agreement dated September 30, 1997. From January 1, 1998, through December 2000 the Company recorded income equal to the amount of cash received from partnership distributions. The Company received distributions at a rate of 70% of project cash flow until December 2000 when a cumulative 24.5% pre-tax rate of return was earned on its original investment. As a result, the Company's equity interest in the partnership has been reduced to 0.1%.

(2) The Company sold its remaining interest in this facility in March 2001.

(3) On October 1, 2001, the Company invested $26.0 million in Endūr, Inc. (formerly known as SuperSite Holdings Corporation). Endūr is responsible for the development, financing, construction, ownership and operation of a high tech data center campus to be located next to Calpine's Los Esteros critical energy facility in San Jose, California. Calpine's Los Esteros facility will supply power to the San Jose data center to be developed by Endūr.

The combined unaudited results of operations and financial position of the Company's equity method affiliates are summarized below (in thousands):

	December 31, 2001	2000	1999
Condensed statements of operations:			
Revenue	$ 401,452	$ 617,914	$ 562,401
Gross profit	148,476	217,777	245,314
Income from continuing operations	99,052	161,852	214,520
Net income	83,161	80,812	113,837
Company's share of net income	8,763	24,639	36,593
Condensed balance sheet:			
Current assets	129,189	130,316	167,107
Non-current assets	1,379,134	1,424,672	1,306,325
Total assets	$1,508,323	$1,554,988	$1,473,432
Current liabilities	145,524	175,764	121,214
Non-current liabilities	687,645	951,013	1,087,329
Total liabilities	$ 833,169	$1,126,777	$1,208,543

The debt on the books of the Company's unconsolidated investments in power projects is not reflected on our balance sheet. At December 31, 2001, investee debt is approximately $737.9 million. Based on the Company's pro rata ownership share of each of the investments, the Company's share would be approximately $248.5 million. However, all such debt is non-recourse to the Company. For the Aries Power Plant construction debt, we and Aquila Energy, a wholly owned subsidiary of UtiliCorp United, have provided support arrangements until construction is completed to cover cost overruns, if any.

The following details the Company's income and distributions from investments in unconsolidated power projects (in thousands):

	Income from Unconsolidated Investments in Power Projects			Distributions		
	For the Years Ended December 31,					
	2001	2000	1999	2001	2000	1999
Sumas Power Plant	$ 15	$12,951	$21,779	$ 15	$12,951	$21,779
Grays Ferry Power Plant	594	4,737	(3)	—	4,500	—
Lockport Power Plant	5,562	4,391	4,255	4,351	3,752	3,741
Gordonsville Power Plant	4,453	4,514	4,299	825	2,950	4,000
Bayonne Power Plant	154	2,196	3,426	155	2,301	2,808
Stony Brook Power Plant	—	(994)	857	—	1,820	370
Auburndale Power Plant	—	599	(712)	—	1,350	3,250
Kennedy International Airport Power Plant	—	(2,769)	1,968		—	3,350
Whitby Cogeneration	684	—	—	637	—	—
Endūr	(721)	—	—	—	—	—
Other	(1,978)	(986)	724	—	355	4,020
Total	$ 8,763	$24,639	$36,593	$5,983	$29,979	$43,318

The Company provides for deferred taxes to the extent that distributions exceed earnings.

7. Notes Receivable

As of December 31, 2001, and December 31, 2000, the components of notes receivable were (in thousands):

	December 31, 2001	December 31, 2000
PG&E (Gilroy) note	$117,698	$ 62,336
Delta note	—	112,050
Panda note	30,818	30,818
Other	21,833	12,906
Total notes receivable	170,349	218,110
Less: Notes receivable, current portion	(12,225)	(183)
Notes receivable, net of current portion	$158,124	$217,927

Calpine Gilroy Cogen, LP ("Gilroy") had a long-term power purchase agreement ("PPA") with Pacific Gas and Electric Company ("PG&E") for the sale of energy through 2018. The terms of the PPA provided for 120 megawatts of firm capacity and up to 10 megawatts of as-delivered capacity. On December 2, 1999, the California Public Utilities Commission approved the restructuring of the PPA between Gilroy and PG&E. Under the terms of the restructuring, PG&E and Gilroy are each released from performance under the PPA effective November 1, 2002. Under the restructured contract, in addition to the normal capacity revenue for the period, Gilroy will earn from September 1999 to October 2002 restructured capacity revenue it would have earned over the November 2002 through March 2018 time period, for which PG&E has issued and will issue notes to the Company. These notes will be paid by PG&E during the period from February 2003 to September 2014. See Note 18 for additional discussion of transactions with PG&E.

In 1999, the Company, together with Bechtel Enterprises ("Bechtel"), began the development of an 874-megawatt gas-fired cogeneration project in Pittsburg, California. As part of this joint venture, the Company had an interest-bearing note from the project, Delta Energy Center, LLC. In November 2001 the Company acquired Bechtel's 50% interest in the Delta Energy Center, and the note was extinguished as part of the acquisition (see Note 4).

On June 23, 2000, the Company entered into a series of turbine sale contracts with a subsidiary of Panda Energy International, Inc. The loan has an interest rate of LIBOR plus 5% and is due in 2003.

8. Notes Payable and Borrowings Under Lines of Credit

The components of notes payable and borrowings under lines of credit and related outstanding letters of credit are (in thousands):

	Borrowings Outstanding December 31,		Letters of Credit Outstanding December 31,	
	2001	2000	2001	2000
Corporate revolving line of credit	$ —	$ 40,000	$373,224	$157,900
Calpine Canada note payable and borrowings under line of credit	—	403,705	—	657
Michael Petroleum note payable	64,750	—	250	—
Other	33,238	12,449	10,810	10,810
Total notes payable and borrowings under lines of credit	$ 97,988	$456,154	$384,284	$169,367
Less: notes payable and borrowings under lines of credit, current portion	23,238	1,087		
Notes payable and borrowings under lines of credit, net of current portion	$ 74,750	$455,067		

In May 2000, Calpine entered into an amended and restated $400.0 million, three-year revolving line of credit (corporate revolving line of credit) with a consortium of commercial lending institutions with the Bank of Nova Scotia as agent, which replaced an existing $100.0 million credit facility. At December 31, 2001, the Company had no borrowings and $373.2 million in letters of credit outstanding under the amended and restated credit facility. Borrowings bear variable interest and interest is paid on the last day of each interest period for such loans, at least quarterly. The credit facility specifies that the Company maintain certain covenants, with which the Company was in compliance as of December 31, 2001 and 2000. Commitment fees related to this line of credit are charged based on the unused credit. The interest rate ranged from 5.50% to 8.00% during 2001 and 7.88% to 9.75% during 2000. This credit facility was amended in March 2002. See Note 24 for further discussion.

During 2001, the Company, through its wholly owned Canadian subsidiaries, maintained three separate Canadian bank line of credit facilities totaling $202.7 million secured by certain of the Company's oil and gas reserves in Canada. The Company had no borrowings and $144.5 million outstanding under these facilities at December 31, 2001 and 2000, respectively. In April 2001, these facilities were canceled. The facilities bore interest at variable rates. The weighted average rate for each of the facilities was 7.14% and 8.52% in 2001 and 2000, respectively.

During 2001, the Company maintained, through its wholly owned Canadian subsidiaries, an unsecured $246.8 million term credit facility and a $20.0 million operating credit facility from Canadian chartered banks. The Company had no borrowings and $159.2 million outstanding under the term credit facility at December 31, 2001 and 2000, respectively. The operating credit facility was reduced to $9.4 million on April 19, 2001, and the unsecured term credit facility was cancelled by the Company in January 2002. Interest rates averaged 6.13% and 7.23% for 2001 and 2000, respectively.

The Company, through its wholly owned Canadian subsidiaries, had two separate issues of $50.0 million unsecured notes. The first issue bore interest at 7.61% and was scheduled to mature on July 11, 2007. The second issue bore interest at 8.06% and was scheduled to mature on December 21, 2010. In April 2001, both note issues were canceled.

As part of the Company's acquisition of Michael Petroleum Corporation ("MPC") through its wholly owned subsidiary Calpine Natural Gas Company, the Company assumed a $75.0 million three-year revolving credit facility with Bank One, N.A. and other banks. The facility provides for a current borrowing base of $65.0 million. Amounts outstanding under the facility bear variable interest. The interest rate ranged from 4.43% to 6.75% during 2001. The line of credit is secured by the Company's oil and gas properties. The Company was out of compliance as of December 31, 2001, with a covenant under the loan agreement. Subsequent to December 31, 2001, the Company initiated the process to obtain a waiver for the covenant but chose to instead repay the outstanding balance under the loan agreement.

Additionally, in connection with repayment of outstanding borrowings in August 2000, the termination of certain credit agreements and the related write-off of unamortized deferred financing costs, the Company recorded an extraordinary loss of $1.2 million, net of tax of $0.8 million, in 2000.

9. Capital Lease Obligations

During 2000 and 2001, the Company assumed and consolidated capital leases in conjunction with certain acquisitions. The asset balances for the leased assets totaled $181.9 million at December 31, 2001, with accumulated amortization of $10.0 million. The primary types of property leased by the Company are power plants and related equipment. The leases generally provide for the lessee to pay taxes, maintenance, insurance, and certain other operating costs of the leased property. The lease terms range from 13 to 28 years.

The following is a schedule by years of future minimum lease payments under capital leases together with the present value of the net minimum lease payments as of December 31, 2001, (in thousands):

Year Ending December 31:	
2002	$ 17,291
2003	17,728
2004	17,961
2005	18,215
2006	19,418
Thereafter	333,850
Total minimum lease payments	424,463
Less: Amount representing interest(1)	(215,038)
Present value of net minimum lease payments	$ 209,425
Less: Capital lease obligation, current portion	(2,206)
Capital lease obligation, net of current portion	$ 207,219

(1) Amount necessary to reduce net minimum lease payments to present value calculated at the implicit interest rates of the leases at their inception.

10. Zero-Coupon Convertible Debentures

On April 30, 2001, the Company completed the sale of $1.0 billion of Zero-Coupon Convertible Debentures Due 2021 ("Zero Coupons") in a private placement under Rule 144A of the Securities Act of 1933. The Zero Coupons are convertible into Calpine common shares at a price of $75.35 per share at the option of the holder at any time. Holders have the right to require the Company to repurchase their Zero Coupons at periodic intervals from 2002 through 2016 at a specified price in cash or with Calpine common stock at the Company's option, except in 2016 when the repurchase price must be paid in cash. As the holders of the Zero Coupons have the right to require the Company to repurchase the debentures during 2002, the Zero Coupons are classified as current. The effective interest rate, after amortization of deferred financing costs, was 2.3% in 2001.

In December 2001 the Company repurchased $122.0 million in aggregate principal amount of its Zero Coupons in open-market purchases. The Company recorded an extraordinary gain of $7.4 million, net of tax of $4.5 million. All repurchased Zero Coupons were retired, bringing the amount of Zero Coupons that remain outstanding at December 31, 2001, to $878.0 million.

See Note 24 for a discussion of the Company's additional repurchases of its Zero Coupons during 2002.

11. Construction/Project Financing

The components of construction/project financing as of December 31, 2001 and 2000, are (in thousands):

	Outstanding at December 31,		Letters of Credit Outstanding at December 31,	
Projects	**2001**	**2000**	**2001**	**2000**
Calpine Construction Finance Company	$ 967,576	$ 544,860	$18,600	$ —
Calpine Construction Finance Company II	2,425,834	156,784	57,303	
Other	—	830,711	—	114,364
Total	3,393,410	1,532,355	$75,903	$114,364
Less: current portion	—	58,486		
Long-term project financing	$3,393,410	$1,473,869		

Calpine Construction Finance Company Debt

In November 1999, the Company entered into a credit agreement for $1.0 billion through its wholly owned subsidiary Calpine Construction Finance Company L.P. with a consortium of banks. The lead arranger was The Bank of Nova Scotia and the lead arranger syndication agent was Credit Suisse First Boston. The non-recourse credit facility is utilized to finance the construction of certain of the Company's gas-fired power plants currently under development. The Company currently intends to refinance this construction facility in the long-term capital markets prior to its four-year maturity of 2003. As of December 31, 2001, the Company had $967.6 million in borrowings outstanding under the facility. Borrowings under this facility bear variable interest. The credit facility specifies that the Company maintain certain covenants, with which the Company was in compliance as of December 31, 2001. The interest rate at December 31, 2001 and 2000, was 3.44% and 8.44%, respectively. The interest rate ranged from 3.44% to 9.50% during 2001.

In October 2000, the Company entered into a credit agreement for $2.5 billion through its wholly owned subsidiary Calpine Construction Finance Company II, LLC with a consortium of banks. The lead arrangers were The Bank of Nova Scotia and Credit Suisse First Boston. The non-recourse credit facility is utilized to finance the construction certain of the Company's gas-fired power plants currently under development. The Company currently intends to refinance this construction facility in the long-term capital markets prior to its four-year maturity of 2004. As of December 31, 2001, the Company had $2.4 billion in borrowings outstanding under the facility. Borrowings under this facility bear variable interest. The credit facility specifies that the Company maintain certain covenants, with which the Company was in compliance as of December 31, 2001. The interest rate at December 31, 2001 and 2000, was 3.68% and 8.20%, respectively. The interest rate ranged from 3.68% to 9.75% during 2001.

Other Project Financing Debt

In 1999 and 2000, the Company assumed project financing debt through the acquisition of the following power plants: Auburndale, Newark and Parlin, Broad River, Pine Bluff, Hog Bayou, RockGen, Morris, DePere, and Dighton. As of December 31, 2001 and 2000, the Company had no borrowings and $830.7 million borrowings outstanding, respectively. The Company repaid the outstanding balance under each individual project loan in 2001. The effective interest rates ranged from 5.51% to 7.68% and 6.43% to 8.24% during 2001 and 2000, respectively.

12. Convertible Senior Notes Due 2006

In December 2001, the Company completed an issuance of $1.1 billion in aggregate principal amount of 4% Convertible Senior Notes Due 2006 ("Convertible Senior Notes") issued directly by Calpine. These securities are convertible, at the option of the holder, into shares of Calpine common stock at a price of $18.07. The proceeds from the offering will be used to retire the Zero Coupons, either in open-market purchases, negotiated transactions or upon exercise by holders of a put option in April 2002 and for general corporate purposes. The effective interest rate on these notes, after amortization of deferred financing costs, was approximately 4.4% in 2001.

See Note 24 for a discussion of the Company's January 3, 2002, issuance of an additional $100.0 million of Convertible Senior Notes.

13. Senior Notes

Senior Notes payable consist of the following as of December 31, 2002 and 2000, (in thousands):

	Interest Rates	First Call Date	December 31, 2001	December 31, 2000	(3) Fair Value as of December 31, 2001	(3) Fair Value as of December 31, 2000
Senior Notes Due 2004	9¼%	1999	$ —	$ 105,000	$ —	$ 105,000
Senior Notes Due 2005	8¼%	(2)	250,000	250,000	223,750	246,700
Senior Notes Due 2006	10½%	2001	171,750	171,750	163,163	178,620
Senior Notes Due 2006	7⅝%	(1)	250,000	250,000	221,250	239,700
Senior Notes Due 2007	8¾%	2002	275,000	275,000	244,750	266,750
Senior Notes Due 2007	8¾%	(2)	125,580	—	111,766	—
Senior Notes Due 2008	7⅞%	(1)	400,000	400,000	356,000	380,320
Senior Notes Due 2008	8½%	(2)	2,030,000	—	1,776,250	—
Senior Notes Due 2008	8⅜%	(2)	155,868	—	143,399	—
Senior Notes Due 2009	7¾%	(1)	350,000	350,000	304,500	332,535
Senior Notes Due 2010	8⅝%	(2)	750,000	750,000	656,250	726,600
Senior Notes Due 2011	8½%	(2)	2,000,000	—	1,760,000	—
Senior Notes Due 2011	8⅞%	(2)	290,840	—	261,756	—
Total			$7,049,038	$2,551,750	$6,222,834	$2,476,225

(1) Not redeemable prior to maturity.

(2) Redeemable at any time prior to maturity.

(3) Represents the market values of the Senior Notes at the respective dates.

The Company has completed a series of public debt offerings since 1994. Interest is payable semiannually at specified rates. Deferred financing costs are amortized on a straight-line basis, which approximates the effective interest method, over the respective lives of the notes. There are no sinking fund or mandatory redemptions of principal before the maturity dates of each offering. Certain of the Senior Note indentures limit the Company's ability to incur additional debt, pay dividends, sell assets and enter into certain transactions. As of December 31, 2001, the Company was in compliance with all debt covenants relating to the Senior Notes. The effective interest rates for each of the Company's Senior Notes outstanding at December 31, 2001, are consistent with the respective notes outstanding during 2000.

Senior Notes Due 2004

Interest on these notes is payable semi-annually on February 1 and August 1 each year. The notes would have matured on February 1, 2004, were redeemable, at the option of the Company, at any time on or after February 1, 1999, at various redemption prices. The effective interest rate on the $105.0 million, after amortization of deferred financing costs, was 9.6% per annum. On June 7, 2001, the Company redeemed all $105.0 million principal amount of the Senior Notes Due 2004 for 100% of the principal amount plus accrued interest to the redemption date. The Company recorded an extraordinary loss of $0.8 million, net of tax of $0.5 million, in connection with this redemption.

Senior Notes Due 2005

Interest on these notes is payable semi-annually on August 15 and February 15. The notes mature on August 15, 2005,or may be redeemed at any time prior to maturity at a redemption price equal to 100% of their principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate on the $250.0 million, after amortization of deferred financing costs, is 8.7% per annum.

Senior Notes Due 2006

Interest on these notes is payable semi-annually on May 15 and November 15 each year and the notes mature on May 15, 2006, or are redeemable, at the option of the Company, at any time on or after May 15, 2001, at various redemption prices. In addition, the Company may redeem up to $63.0 million of the Senior Notes Due 2006 from the proceeds of any public equity offering. The effective interest rate on the $171.8 million, after amortization of deferred financing costs, is 10.8% per annum.

Interest on the 7⅝% notes is payable semi-annually on April 15 and October 15 and the notes mature on April 15, 2006, and are not redeemable prior to maturity. The effective interest rate on the $250.0 million, after amortization of deferred financing costs, is 7.9% per annum.

Senior Notes Due 2007

Interest on the $275 million principal senior notes is payable semi-annually on January 15 and July 15 each year. These notes mature on July 15, 2007, or are redeemable, at the option of the Company, at any time on or after July 15, 2002, at various redemption prices. In addition, the Company may redeem up to $96.3 million of the Senior Notes Due 2007 from the proceeds of any public equity offering. The effective interest rate on the $275.0 million, after amortization of deferred financing costs, is 9.1% per annum.

In October 2001 Calpine Canada Energy Finance ULC ("Energy Finance"), a wholly owned subsidiary of the Company, issued C$200.0 million (US$125.6 million as of December 31, 2001) of Senior Notes Due 2007 ("Energy Finance Senior Notes Due 2007"). Interest is payable semi-annually on April 15 and October 15. The Notes mature on October 15, 2007; however, they may be redeemed prior to maturity, at any time in whole or from time to time in part, at a redemption price equal to the greater of (a) the "Discounted Value" of the senior notes, which equals the sum of the present values of all remaining scheduled payments of principal and interest, or (b) 100% of the principal amount plus accrued and unpaid interest to the redemption date. The Notes are fully and unconditionally guaranteed by the Company. The effective interest rate, after amortization of deferred financing costs, is 9.3% per annum.

Senior Notes Due 2008

Interest on the 7⅞% notes is payable semi-annually on April 1 and October 1 each year. These notes mature on April 1, 2008, and are not redeemable prior to maturity. The effective interest rate, after amortization of deferred financing costs, is 8.0% per annum.

In April 2001 Energy Finance issued $1,500.0 million in aggregate principal amount of 8½% Senior Notes Due 2008. In October 2001 Energy Finance issued an additional $530.0 million of 8½% Senior Notes Due 2008. Together, these issues form a single series ("Energy Finance Senior Notes Due 2008") which is fully and unconditionally guaranteed by the Company. Interest on these notes is payable semi-annually on May 1 and November 1. The notes mature on May 1, 2008, or may be redeemed prior to maturity at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate, after amortization of deferred financing costs, is 8.7% per annum.

In October 2001 the Company's wholly owned subsidiary, Calpine Canada Energy Finance II ULC ("Energy Finance II"), issued €175.0 million (US$155.9 million as of December 31, 2001) of 8⅜% Senior Notes Due 2008 ("Energy Finance II Senior Notes Due 2008"). Interest on these notes is payable semi-annually on April 15 and October 15 and the notes mature on October 15, 2008, or may be redeemed prior to maturity at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate, after amortization of deferred financing costs, is 8.8% per annum.

Senior Notes Due 2009

Interest on these notes is payable semi-annually on April 15 and October 15. The notes mature on April 15, 2009, and are not redeemable prior to maturity. The effective interest rate, after amortization of deferred financing costs, is 7.9% per annum.

Senior Notes Due 2010

Interest on these notes is payable semi-annually on August 15 and February 15 and the notes mature on August 15, 2010, and may be redeemed at any time prior to maturity at a redemption price equal to 100% of their principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate, after amortization of deferred financing costs, is 8.8% per annum.

Senior Notes Due 2011

In February 2001 the Company completed an offering of $1,150.0 million in aggregate principal amount of 8 ½% Senior Notes Due 2011. In October 2001 the Company issued an additional $850.0 million of 8½% Senior Notes Due 2011. Interest on these notes is payable semi-annually on February 15 and August 15 and the notes mature on February 15, 2011, and may be redeemed prior to maturity at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate, after amortization of deferred financing costs, is 8.6% per annum.

In October 2001 the Company's wholly owned subsidiary, Energy Finance II, issued £200.0 million (US$290.8 million as of December 31, 2001) of 8⅞% Senior Notes Due 2011 ("Energy Finance II Senior Notes Due 2011"). Interest on the notes is payable semi-annually on April 15 and October 15 and the notes mature on October 15, 2011, and may be redeemed prior to maturity at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate, after amortization of deferred financing costs, is 9.3% per annum.

Energy Finance and Energy Finance II are wholly-owned finance subsidiaries of Calpine. The securities are fully and unconditionally guaranteed by Calpine. There are no restrictions under the indentures governing the Senior Notes or under the guarantees thereof issued by Calpine on the ability of Calpine to obtain funds from these subsidiaries by dividend or loan.

During the third quarter of 2001, the Company borrowed a total of $1.2 billion under three bridge credit facilities (which ranked equally with Senior Notes) to finance several acquisitions. These facilities were refinanced with the October 2001 issuance of long-term Senior Notes. The Company recorded an extraordinary loss of $0.6 million, net of tax of $0.4 million, related to the write off of unamortized deferred financing costs.

Annual Debt Maturities

The annual principal maturities of the Zero Coupons, notes payable and borrowings under lines of credit, project financing, Convertible Senior Notes Due 2006, senior notes and capital lease obligations as of December 31, 2001, are as follows (in thousands):

2002	$ 903,444
2003	1,035,143
2004	2,429,106
2005	253,782
2006	1,527,115
Thereafter	6,579,271
Total	$12,727,861

14. Trust Preferred Securities

In 1999 and 2000, the Company, through its wholly owned subsidiaries, Calpine Capital Trust, Calpine Capital Trust II, and Calpine Capital Trust III, statutory business trusts created under Delaware law, (collectively, "the Trusts") completed offerings of Remarketable Term Income Deferrable Equity Securities ("HIGH TIDES") at a value of $50.00 per share.

	Issue Date	Shares	Interest Rate	Balance December 31, 2001	Balance December 31, 2000	Conversion Ratio — Number of Common Shares Per 1 High Tide	First Redemption Date	Initial Redemption Price
High Tides I	October 1999	5,520,000	5.75%	$ 268,441	$ 268,185	3.4620	November 5, 2002	101.440%
High Tides II	January and February 2000	7,200,000	5.50%	351,182	350,865	1.9524	February 5, 2003	101.375%
High Tides III	August 2000	10,350,000	5.00%	503,401	503,440	1.1510	August 5, 2003	101.250%
		23,070,000		$1,123,024	$1,122,490			

The net proceeds from each of the offerings were used by the Trusts to invest in convertible subordinated debentures of the Company, which represent substantially all of the respective trusts' assets. The Company has effectively guaranteed all of the respective trusts' obligations under the trust preferred securities. The trust preferred securities have liquidation values of $50.00 per share. The Company has the right to defer the interest payments on the debentures for up to twenty consecutive quarters, which would also cause a deferral of distributions on the trust preferred securities. Currently, the Company has no intention of deferring interest payments on the debentures.

The trust preferred securities are convertible into shares of the Company's common stock at the holder's option on or prior to the tender notification date. Additionally, the HIGH TIDES may be redeemed at any time on or after the initial redemption date. The redemption price declines to 100% during the one year following the initial redemption date.

15. Provision for Income Taxes

The jurisdictional components of income (loss) before provision for income taxes at December 31, 2001, 2000 and 1999, are as follows (in thousands):

	2001	2000	1999
U.S.	$906,512	$538,033	$158,216
International	79,811	100,613	17,642
Income before provision for income taxes	$986,323	$638,646	$175,858

The provision for income taxes for the years ended December 31, 2001, 2000, and 1999 consists of the following (in thousands):

	2001	2000	1999
Current:			
Federal	$198,165	$214,169	$26,564
State	28,282	40,596	6,728
Foreign	5,810	—	—
Deferred:			
Federal	101,809	(30,573)	23,142
State	(10,961)	(7,852)	4,305
Revision in prior years' tax estimates	—	—	1,234
Foreign	22,156	48,469	6,085
Total provision	$345,261	$264,809	$68,058

The Company's effective rate for income taxes for the years ended December 31, 2001, 2000, and 1999 differs from the United States statutory rate, as reflected in the following reconciliation:

	2001	2000	1999
United States statutory tax rate	35.0%	35.0%	35.0%
State income tax, net of federal benefit	1.7	3.9	3.6
Depletion and other permanent items	0.3	—	—
Foreign tax at rates other than U.S. statutory	(1.7)	1.7	(0.5)
Other, net	(0.3)	0.9	0.6
Effective income tax rate	35.0%	41.5%	38.7%

The components of the deferred income taxes, net as of December 31, 2001 and 2000, are as follows (in thousands):

	2001	2000
Expenses deductible in a future period	$ 26,542	$ 32,293
Net operating loss and credit carryforwards	35,341	41,472
Taxes related to risk management activities	66,549	—
Other differences	11,604	4,617
Deferred tax assets	140,036	78,382
Property differences	(1,037,537)	(681,043)
Other differences	(66,845)	(15,868)
Deferred tax liabilities	(1,104,382)	(696,911)
Net deferred income taxes	$ (964,346)	$(618,529)

The net operating loss and credit carryforwards consist of federal and state net operating loss carryforwards which expire 2005 through 2014. The federal and state net operating loss carryforwards available are subject to limitations on annual usage. It is expected that they will be fully utilized before expiring. Realization of the deferred tax assets and federal net operating loss carryforwards is dependent, in part, on generating sufficient taxable income prior to expiration of the loss carryforwards. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

Cumulative undistributed earnings of foreign subsidiaries was approximately $29.1 million at December 31, 2001. The Company considers these earnings to be permanently reinvested outside the United States. Accordingly, no U.S. deferred taxes have been recorded with respect to such earnings. Should the earnings be remitted as dividends, additional U.S. taxes may be applicable, net of available foreign tax credits. This tax is estimated to be approximately $12.1 million.

16. Employee Benefit Plans

Retirement Savings Plan

The Company has a defined contribution savings plan under Section 401(a) and 501(a) of the Internal Revenue Code. The plan provides for tax deferred salary deductions and after-tax employee contributions. Employees are immediately eligible upon hire. Contributions include employee salary deferral contributions and employer profit-sharing contributions of 3% of employees' salaries up to $5,100 per year, made entirely in cash. Effective January 1, 2002, the Company increased its profit sharing contribution, to 4% of employees' salaries up to $8,000 per year. Employer profit-sharing contributions in 2001, 2000, and 1999 totaled $6.9 million, $3.1 million, and $1.3 million, respectively.

1996 Employee Stock Purchase Plan

The Company adopted the 1996 Employee Stock Purchase Plan in July 1996. Eligible employees could purchase up to 2,200,000 shares of common stock at semi-annual intervals through periodic payroll deductions. Purchases were limited to 15 percent of an employee's eligible compensation, and to a maximum value of $25,000 per calendar year based on the IRS code Section 423 limitation. Shares were purchased on January 31, and the plan terminated on February 1, 2000. Under the 1996 plan, 408,300 shares were issued at a weighted average fair value of $2.67 per share in 2000. The purchase price is 85% of the lower of (i) the fair market value of the common stock on the participant's entry date into the offering period, or (ii) the fair market value on the semi-annual purchase date.

2000 Employee Stock Purchase Plan

The Company adopted the 2000 Employee Stock Purchase Plan ("ESPP") in May 2000. Eligible employees may purchase up to 4,000,000 shares of common stock at semi-annual intervals through periodic payroll deductions. Purchases are limited to a maximum value of $25,000 per calendar year based on the IRS code Section 423 limitation. Shares are purchased on May 31 and November 30 of each year until termination of the plan on May 31, 2010. Under the ESPP, 1,124,851 and 221,853 shares were issued at a weighted average fair value of $21.05 and $23.18 per share in 2001 and 2000, respectively. The purchase price is 85% of the lower of (i) the fair market value of the common stock on the participant's entry date into the offering period, or (ii) the fair market value on the semi-annual purchase date.

1996 Stock Incentive Plan

The Company adopted the 1996 Stock Incentive Plan ("SIP") in September 1996. The SIP succeeded the Company's previously adopted stock option program. The Company accounts for the SIP under APB Opinion No. 25, "Accounting for Stock Issued to Employees" under which no compensation cost has been recognized. Had compensation cost for the SIP been determined consistent with the methodology of SFAS No. 123, "Accounting for Stock-Based Compensation", the Company's net income and earnings per share would have been reduced to the following pro forma amounts (in thousands, except per share amounts):

	2001	2000	1999
Net income			
As reported	$648,105	$372,602	$106,650
Pro Forma	619,598	351,219	94,313
Earnings per share data:			
Basic earnings per share			
As reported	$ 2.14	$ 1.33	$ 0.47
Pro Forma	2.04	1.25	0.42
Diluted earnings per share			
As reported	$ 1.87	$ 1.19	$ 0.45
Pro Forma	1.79	1.13	0.39

The fair value of options granted in 2001, 2000, and 1999 was $22.30, $16.09, and $6.42 on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions: expected dividend yields of 0%, expected volatility of 76% for 2001, 67% for 2000, and 69% for 1999, risk-free interest rates of 5.02% for 2001, 6.69% for 2000 and 5.74% for 1999, and expected lives of 7 years for 2001, 2000, and 1999.

For the year ended December 31, 2001, the Company had granted options to purchase 2,841,518 shares of common stock. Over the life of the SIP, options exercised have equaled 12,371,413, leaving 27,691,264 granted and not yet exercised. Under the SIP, the option exercise price generally equals the stock's fair market value on date of grant. The SIP options generally vest ratably over four years and expire after 10 years.

In connection with the merger with Encal, the Company adopted Encal's existing stock option plan. All outstanding options under the Encal stock option plan were converted at the time of the merger into options to purchase Calpine stock. No new options may be granted under the Encal stock option plan.

Changes in options outstanding, granted, exercisable and cancelled during the years 2001, 2000, and 1999, under the option plans of Calpine and Encal were as follows:

	Available for Option or Award	Outstanding Number of Shares	Weighted Average Exercise Price
Outstanding December 31, 1998	10,993,481	24,109,508	1.72
Additional shares reserved	1,911,527	—	—
Granted	(8,604,108)	8,604,108	7.32
Exercised	—	(1,686,228)	3.54
Cancelled	61,799	(61,799)	15.20
Outstanding December 31, 1999	4,362,699	30,965,589	3.18
Additional shares reserved	2,820,757	—	—
Granted	(4,379,129)	4,379,129	23.21
Exercised	—	(4,533,946)	1.89
Cancelled	182,742	(182,742)	17.68
Outstanding December 31, 2000	2,987,069	30,628,030	6.11
Additional shares reserved	2,837,150	—	—
Granted	(3,008,541)	3,008,541	42.90
Exercised	—	(5,460,390)	8.12
Cancelled	484,917	(484,917)	34.24
Cancelled options available for award	(1,265,232)	—	—
Outstanding December 31, 2001	2,035,363	27,691,264	$ 9.32
Options exercisable:			
December 31, 1999		17,829,699	1.19
December 31, 2000		18,980,332	2.68
December 31, 2001		18,656,835	3.84

The following tables summarizes information concerning outstanding and exercisable options at December 31, 2001:

Range of Exercise Prices	Number of Shares	Weighted Exercise Remaining Contractual Life in Years	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
$ 0.065 — $ 0.065	3,053,940	1.00	$0.065	3,053,940	$ 0.065
$ 0.570 — $ 0.615	3,828,920	3.06	0.596	3,828,920	0.596
$ 0.645 — $ 2.150	5,239,722	5.24	1.599	4,470,722	1.504
$ 2.195 — $ 2.250	2,127,300	5.29	2.250	2,067,300	2.250
$ 2.345 — $ 3.860	4,113,810	7.01	3.752	1,997,410	3.661
$ 4.240 — $ 9.955	3,322,099	7.57	9.209	1,699,391	9.145
$ 10.000 — $ 28.270	3,051,953	7.37	20.506	1,284,773	19.045
$ 28.830 — $ 52.200	2,855,136	7.56	44.554	247,544	40.572
$ 52.540 — $ 56.990	67,384	4.57	53.231	6,835	53.055
$100.000 — $100.000	31,000	8.70	100.00	—	—
Total	27,691,264	5.49	$9.323	18,656,835	$ 3.837

17. Stockholders' Equity

Common Stock

Increase in Authorized Shares — On July 26, 2001, the Company filed amended certificates with the Delaware Secretary of State to increase the number of authorized shares of common stock to 1,000,000,000 from 500,000,000 and the number of authorized shares of Series A Participating Preferred Stock to 1,000,000 from 500,000.

Stock Splits — On September 20, 1999, the Board of Directors authorized a two-for-one stock split of the Company's common stock, in the form of a stock dividend, effective October 7, 1999, payable to stockholders of record as of September 28, 1999. The Company transferred $27,000 to common stock from additional paid-in capital, representing the aggregate par value of the shares issued under the stock split.

On May 18, 2000, the Board of Directors authorized a two-for-one stock split of the Company's common stock, in the form of a stock dividend, effective June 8, 2000, payable to stockholders of record as of May 29, 2000. The Company transferred $64,000 to common stock from additional paid-in capital, representing the aggregate par value of the shares issued under the stock split.

On October 23, 2000, the Board of Directors authorized a two-for-one stock split of the Company's common stock, in the form of a stock dividend, effective November 14, 2000, payable to stockholders of record as of November 6, 2000. The Company transferred $140,000 to common stock from additional paid-in capital, representing the aggregate par value of the shares issued under the stock split.

All references to the number of common shares and the per common share amounts have been restated to give retroactive effect to the above stock splits for all periods presented.

Equity Offering — On August 9, 2000, Calpine completed a public offering of 23,000,000 shares of common stock at $34.75 per share. The gross proceeds from the offering were $799.3 million.

Preferred Stock and Preferred Share Purchase Rights

On June 5, 1997, Calpine adopted a stockholders' rights plan to strengthen Calpine's ability to protect Calpine's stockholders. The plan was amended on September 19, 2001. The rights plan is designed to protect against abusive or coercive takeover tactics that are not in the best interests of Calpine or its stockholders. To implement the rights plan, Calpine declared a dividend of one preferred share purchase right for each outstanding share of Calpine's common stock held on record as of June 18, 1997, and directed the issuance of one preferred share purchase right with respect to each share of Calpine's common stock that shall become outstanding thereafter until the rights become exercisable or they expire as described below. On December 31, 2001, there were 307,058,751 rights outstanding. Each right initially represents a contingent right to purchase, under certain circumstances, one one-thousandth of a share, called a "unit," of Calpine's Series A Participating Preferred Stock, par value $.001 per share, at a price of $140.00 per unit, subject to adjustment. The rights become exercisable and trade independently from Calpine's common stock upon the public announcement of the acquisition by a person or group of 15% or more of Calpine's common stock, or ten days after commencement of a tender or exchange offer that would result in the acquisition of 15% or more of Calpine's common stock. Each unit purchased upon exercise of the rights will be entitled to a dividend equal to any dividend declared per share of common stock and will have one vote, voting together with the common stock. In the event of Calpine's liquidation, each share of the participating preferred stock will be entitled to any payment made per share of common stock.

If Calpine is acquired in a merger or other business combination transaction after a person or group has acquired 15% or more of Calpine's common stock, each right will entitle its holder to purchase at the right's exercise price a number of the acquiring company's shares of common stock having a market value of twice the right's exercise price. In addition, if a person or group acquires 15% or more of Calpine's common stock, each right will entitle its holder (other than the acquiring person or group) to purchase, at the right's exercise price, a number of fractional shares of Calpine's participating preferred stock or shares of Calpine's common stock having a market value of twice the right's exercise price.

The rights remain exercisable for up to 90 days following a triggering event (such as a person acquiring 15% or more of the Company's common Stock). The rights expire on June 18, 2007, unless redeemed earlier by Calpine. Calpine can redeem the rights at a price of $.01 per right at any time before the rights become exercisable, and thereafter only in limited circumstances.

Comprehensive Income

Comprehensive income is the total of net income and all other non-owner changes in equity. Comprehensive income includes the Company's net income for the year. It also includes unrealized gains and losses from derivative instruments that qualify as cash flow hedges. The total comprehensive income of $444.6 million for the year ended December 31, 2001, represents the net of the Company's 2001 net income of $648.1 million and its unrealized other comprehensive loss of $203.5 million. The other comprehensive loss represents the decline in the market value of open derivative positions during the year. During the year as certain derivative positions are settled, the resulting gain or loss is realized and is charged to income. The recognition of these gains and losses is referred to as a reclassification adjustment. Other comprehensive income also includes the effect of foreign currency translation adjustments. Prior to the current reporting year, the only items affecting the Company's accumulated OCI balance resulted from the translation of its Canadian subsidiaries' balance sheets into U.S. dollars and the corresponding tax effects thereon.

The Company reports Accumulated Other Comprehensive Income (Loss) (AOCI) in its consolidated balance sheet. This balance reflects the cumulative balance of comprehensive income items. This balance is the sum of the ending AOCI balance from the prior period and the other comprehensive loss (OCI) from the current period. Accordingly, accumulated other comprehensive loss of $226.6 million as of December 31, 2001 is the sum of the current year's unrealized OCI loss of $203.5 million and the ending OCI balance at December 31, 2000 of $23.1 million.

Under the reporting guidance of SFAS No. 130, "Reporting Comprehensive Income," unrealized gains/losses from foreign currency translation are not viewed as deferred losses. As a result, from the total accumulated OCI loss at December 31, 2001, of $226.6 million, only the losses pertaining to cash flow hedges will be recognized in earnings in future periods. As disclosed in Note 19, these losses total $299.7 million on a pre-tax basis and $183.3 million net of tax. Below is a reconciliation of the Company's comprehensive loss from derivatives (as disclosed in Note 19) to the accumulated other comprehensive loss in stockholders equity on the balance sheet at December 31, 2001 (in thousands):

Total pre-tax unrealized comprehensive loss on cash flow hedges	$(299,740)
Add: accumulated other comprehensive loss at December 31, 2000(1)	(23,085)
Add: loss on foreign currency translation during the year, net of tax benefit of $14,563	(20,112)
Less: tax benefit from unrealized loss on open derivative positions(2)	116,363
Accumulated Other Comprehensive Loss at December 31, 2001	$(226,574)

(1) Accumulated other comprehensive loss at December 31, 2000, is deducted because prior to January 1, 2001, there were no OCI balances related to cash flow hedges.

(2) OCI tax benefit from unrealized loss on cash flow hedge of $116,363 is disclosed in Note 19.

18. Significant Customers

In 2001, Enron Corp. ("Enron") was a significant customer and accounted for more than 10% of the Company's annual consolidated revenues. In 2001, 2000 and 1999, Pacific Gas & Electric Company ("PG&E") was a significant customer. In 1999, Texas Utilities Electric Company ("TUEC") was a significant customer.

Revenues earned from the significant customers for the years ended December 31, 2001, 2000, and 1999 were as follows (in thousands):

	2001	2000	1999
Revenues:			
PG&E(1)(2)	$ 723,062	$624,458	$215,264
TUEC	*	*	144,016
Enron	1,671,737	*	*

Receivables due from the significant customers at December 31, 2001 and 2000, were as follows (in thousands):

	2001	2000
Receivables:		
PG&E Accounts Receivable(2)	$ 46,545	$204,448
PG&E Notes Receivable(3)	117,698	62,336
PG&E Total	$164,243	$266,784
Enron Accounts Receivable	$ 75,002	*

* Customer not significant in respective year.

(1) See Note 23 for further discussion of the California energy situation.

(2) In addition to the accounts receivable shown in the table, the Company had a receivable of $224.2 million from the sale of the pre-bankruptcy petition PG&E receivables on December 31, 2001. This receivable was paid in full from an escrow account in January 2002.

(3) Payments of the PG&E notes receivable are scheduled from February 2003 to September 2014 (See Note 7 for further discussion).

Enron

During 2001, the Company, primarily through its CES subsidiary, transacted a significant volume of business with units of Enron, mainly Enron Power Marketing, Inc. ("EPMI") and Enron North America Corp. ("ENA"). ENA is the parent corporation of EPMI. Enron is the direct parent corporation of ENA. Most of these transactions were contracts for sales and purchases of power and gas for hedging purposes, some of which extended out as far as 2009. In October and November of 2001, Enron announced a series of developments including restatement of the last four years of earnings, an investigation by the Securities and Exchange Commission relating to the adequacy of Enron's disclosures of certain off-balance sheet financial transactions or structures and dismissals of certain members of senior management. On December 2, 2001, Enron Corp. and certain of its subsidiaries filed voluntary petitions for Chapter 11 reorganization with the U.S. Bankruptcy Court for the Southern District of New York. EPMI and ENA are among the subsidiaries of Enron that filed for reorganization on December 2, 2001.

The Company, primarily through our subsidiary CES, purchased significant amounts of fuel and power from ENA and EPMI prior to the bankruptcy filings, which gave rise to current accounts payable and open contract fair value positions. These purchases must be included in an overall understanding of the Company's Enron exposure. For the year ended December 31, 2001, CES had fuel and power purchases from ENA and EPMI of $1.6 billion (See table below).

The following table sets forth information regarding the Company's transactions with Enron for the year ended December 31, 2001, (in thousands of dollars and thousands of MWh's, in the case of electricity transactions, and thousands of MMBtu's, in the case of oil and gas transactions):

	For the Year Ended December 31, 2001	
	Dollar	Volume
Electric generation and marketing revenue (electricity and steam revenue and sales of purchased power)	$1,477,694	18,584
Oil and gas production and marketing revenue (sales of purchased gas)	189,323	32,340
Other revenue	4,720	
Total power and fuel and other revenue from Enron	$1,671,737	
Electric generation and marketing expense (Purchased power expense)	$1,473,833	16,999
Fuel expense (cost of oil and natural gas burned by power plants and natural gas derivative mark-to-market gain	152,973	25,006
Total CES power and fuel expenses related to Enron(1)	$1,626,806	

(1) Expenses of CES only, as other Enron expenses incurred are not material.

Unrealized pre-tax losses on derivatives designated as effective cash flow hedges that were recorded in OCI associated with Enron activity for the year ended December 31, 2001, were $118.6 million. Recognized gains on derivatives not designated as hedges associated with Enron activity were $381.8 million for the year ended December 31, 2001. Recognized losses on derivatives not designated as hedges associated with Enron activity were $495.0 million for the year ended December 31, 2001. Recognized gross gains (losses) on fair value hedges (which are perfectly offset by the gains and losses on the hedged items) associated with Enron activity were $9.8 million and $(31.6) million, respectively, for the year ended December 31, 2001.

The sales to and purchases from various Enron subsidiaries were mostly hedging and optimization transactions, and in most cases the purchases and sales are not related and should not be netted to try to gauge the profitability of transactions with Enron subsidiaries.

The Company reserved $13.1 million related to unrealized mark to market gains generated by Enron's insolvency, which caused earnings recognition for contracts that had previously been exempted from SFAS No. 133 accounting and which caused cash flow hedges to cease to be effective and mark to market in earnings until termination.

On November 14, 2001, CES, ENA and EPMI entered into a Master Netting, Setoff and Security Agreement (the "Netting Agreement"). The Netting Agreement permits CES, on the one hand, and ENA and EPMI, on the other hand, to set off amounts owed to each other under an ISDA Master Agreement between CES and ENA, an Enfolio Master Firm Purchase/Sale Agreement between CES and ENA and a Master Energy Purchase/Sale Agreement between CES and EPMI (in each case, after giving effect to the netting provisions contained in each of these agreements). Based on legal analysis of the Netting Agreement, the Company believes it has no net collection exposure to Enron.

In assessing its exposure to ENA and EPMI, the Company analyzes its accounts receivable and accounts payable balances on contracts that have already settled and also the fair value (mark-to-market value) of the contracts that have not settled. Following are the accounts receivable and accounts payable balances, presented on both a gross and net basis, as well as the gross and net fair values of the open contracts with ENA and EPMI at December 31, 2001. The positive net positions have realization exposure, while the negative net positions are existing or potential obligations.

	Receivables/Payables			Fair Values			
	Gross Receivable	Gross Payable	Net Receivable (Payable)	Gross Fair Value(+)	Gross Fair Value(−)	Net Open Positions Value	Total
Enron North America	$ 14.6	$ (17.7)	$ (3.1)	$1,549.0	$(1,823.0)	$(274.0)	$(277.1)
Enron Power Marketing	237.5	(203.0)	34.5	462.0	(356.0)	106.0	140.5
Total	252.1	(220.7)	31.4	2,011.0	(2,179.0)	(168.0)	(136.6)

After netting the receivables and payables and the value of the open positions from ENA and EPMI, the Company has an existing or future obligation of $136.6 million (the sum of the net receivable of $31.4 million and the net open positions value of $(168.0) million) as of December 31, 2001, which obligation will be offset by CES' losses, damages, attorneys' fees and other expenses arising from the default by Enron.

Based on the above, the Company had no net exposure to ENA and EPMI at December 31, 2001. The Company has not established any reserve against potential ENA and EPMI exposure.

The Company's treasury department includes a credit group focused on monitoring and managing counterparty risk. The credit group monitors the net exposure with each counterparty on a daily basis. The analysis is performed on a mark-to-market basis using the forward curves audited by the Company's Risk Controls group. The net exposure is compared against a counterparty credit risk threshold which is determined based on the counterparty's credit ratings, evaluation of the financial statements and bond values. The credit department monitors these thresholds to determine the need for additional collateral or an adjustment to activity with the counterparty.

PG&E

The Company's northern California Qualifying Facility ("QF") subsidiaries sell power to PG&E under the terms of long-term contracts at eleven facilities. On April 6, 2001, PG&E filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. PG&E is the regulated subsidiary of PG&E Corporation, and the information on PG&E disclosed herein excludes PG&E Corporation's non-regulated subsidiary activity. The Company has transactions with certain of the non-regulated subsidiaries, which have not been affected by PG&E's bankruptcy. On July 12, 2001, the U.S. Bankruptcy Court for the Northern District of California approved the agreement the Company had entered into with PG&E to modify and assume all of Calpine's QF contracts with PG&E. Under the terms of the agreement, the Company will continue to receive its contractual capacity payments plus a five-year fixed energy price component that averages 5.37 cents per kilowatt-hour in lieu of the short run avoided cost. In addition, all past due receivables under the QF contracts were elevated to administrative priority status and are to be paid to the Company, with interest, upon the effective date of a confirmed plan of reorganization. On September 20, 2001, PG&E filed its proposed plan of reorganization with the bankruptcy court.

As of April 6, 2001, the date of PG&E's bankruptcy filing, the Company had recorded $265.6 million (unaudited estimate) in accounts receivable with PG&E under the QF contracts, plus $68.7 million (unaudited estimate) in notes receivable not yet due and payable. PG&E has paid currently for power delivered after April 6, 2001.

In December 2001 the bankruptcy court approved an agreement between Calpine and PG&E whereby PG&E is to repay the $265.6 million in past due pre-petition receivables plus accrued interest ($10.3 million through December 31, 2001) thereon beginning on December 31, 2001, and with monthly payments thereafter over the next 11 months. Shortly following receipt of this bankruptcy court approval and the first payments from PG&E on December 31, 2001, the Company sold the remaining PG&E receivables to a third party at a $9.0 million discount.

CPUC Proceeding Regarding QF Contract Pricing for Past Periods. Our QF contracts with PG&E provide that the CPUC has the authority to determine the appropriate utility "avoided cost" to be used to set energy payments for certain QF contracts by determining the short run avoided cost ("SRAC") energy price formula. In mid 2000, our QF facilities elected the option set forth in Section 390 of the California Public Utility Code, which provides QFs the right to elect to receive energy payments based on the California Power Exchange ("PX") market clearing price instead of the price determined by SRAC. Having elected such option, we were paid based upon the PX zonal day ahead clearing price ("PX Price") from summer 2000 until January 19, 2001, when the PX ceased operating a day ahead market. The CPUC has conducted proceedings (R.99-11-022) to determine whether the PX Price was the appropriate price for the energy component upon which to base payments to QFs which had elected the PX-based pricing option. The CPUC at one point issued a proposed decision to the effect that the PX Price was the appropriate price for energy payments under the California Public Utility Code but tabled it, and a final decision has not been issued to date. Therefore, it is possible that the CPUC could order a payment adjustment based on a different energy price determination. We believe that the PX Price was the appropriate price for energy payments but there can be no assurance that this will be the outcome of the CPUC proceedings.

Current California QF Contract Pricing. When the PX ceased operation on January 19, 2001, the CPUC ordered that the QFs that had previously switched to the PX Price be switched back to the applicable SRAC energy price formula. On June 14, 2001, however, the CPUC issued an order (Decision 01-06-015) (the "June 2001 Decision") that authorized the California utilities, including PG&E, to amend QF contracts to elect a fixed energy price component that averages 5.37 cents per kilowatt-hour for a five-year term under those contracts in lieu of using the SRAC energy price formula. By this order, the CPUC authorized the QF contract energy price amendments without further CPUC concurrence. As part of the agreement we entered into with PG&E pursuant to which PG&E, in bankruptcy, agreed to assume its QF contracts with us, PG&E

agreed with us to amend these contracts to adopt the fixed price component that averages 5.37 cents pursuant to the June 2001 Decision. This election became effective as of July 16, 2001. As a result of the June 2001 Decision and our agreement with PG&E to amend the QF contracts to adopt the fixed price energy component, the energy price component in our QF contracts is now fixed for five years. As of July 1, 2006, the energy payment under the QF contracts with PG&E will be determined by the CPUC in accordance with its determination of the SRAC energy price formula.

The Company had a combined accounts receivable balance of $22.7 million as of December 31, 2001, from the California Independent System Operator Corporation ("CAISO") and Automated Power Exchange, Inc. ("APX"). Of this balance, $9.4 million relates to past due balances prior to the PG&E bankruptcy filing. The Company has provided a full reserve for these past due receivables. CAISO's ability to pay the Company is directly impacted by PG&E's ability to pay CAISO. APX's ability to pay the Company is directly impacted by PG&E's ability to pay the PX, which in turn would pay APX for energy delivered by the Company through APX. The PX ceased operating in January 2001. See Note 23 for an update on the FERC investigation into the California wholesale markets.

The Company also had an accounts receivable balance of $34.0 million at December 31, 2001, from the California Department of Water Resources ("DWR"). Past due accounts receivable from the California Department of Water Resources at December 31, 2001, totaled $1.0 million. The Company accordingly has determined that there is no reserve needed. The Company's sales to DWR are primarily pursuant to long term contracts, so the Company has not had the same degree of collectibility problems that some generators selling into the day ahead market have experienced because of administrative and/or political issues between the CAISO and DWR.

On December 11, 2001, Calpine announced that it was meeting with officials from the State of California at their request to discuss whether, and if so how, the long-term contracts with DWR could be modified. No definitive modifications have been agreed to and the discussions have been ongoing.

19. Derivative Instruments

As an independent power producer primarily focused on generation of electricity using gas-fired turbines, the Company's natural physical commodity position is "short" fuel (i.e., natural gas consumer) and "long" power capacity (i.e., electricity seller). To manage forward exposure to price fluctuation in these and (to a lesser extent) other commodities, the Company enters into derivative commodity instruments. All transactions are subject to the Company's risk management policy which prohibits positions that exceed total portfolio generation and fuel requirements. Any hedging, balancing, or optimization activities that the Company engages in are directly related to the Company's asset-based business model of owning and operating gas-fired electric power plants and are designed to protect the Company's "spark spread" (the difference between the Company's fuel cost and the revenue it receives for its electric generation). The Company hedges exposures that arise from the ownership and operation of power plants and related sales of electricity and purchases of natural gas, and the Company utilizes derivatives to optimize the returns the Company is able to achieve from these assets for the Company's shareholders. While certain of the Company's contracts are considered energy trading contracts as defined in Emerging Issues Task Force ("EITF") Issue No. 98-10, the Company's traders have very low capital at risk and value at risk limits for energy trading, and its risk management policy limits, at any given time, its net sales of power to its generation capacity and limits its net purchases of gas to its fuel consumption requirements on a total portfolio basis. This model is markedly different from that of companies that engage in significant commodity trading operations that are unrelated to underlying physical assets. Derivative commodity instruments are accounted for under the requirements of SFAS No. 133, as amended.

The Company enters into various foreign currency swap agreements to hedge against changes in exchange rates on certain of its Senior Notes denominated in currencies other than the U.S. dollar. The foreign currency swaps effectively convert floating exchange rates into fixed exchange rates so that the Company can predict with greater assurance what its U.S. dollar cost will be for purchasing foreign currencies to satisfy the interest and principal payments on these Senior Notes.

The Company enters into various interest rate swap agreements to hedge against changes in floating interest rates on certain of its project financing facilities. The interest rate swap agreements effectively convert floating rates into fixed rates so that the Company can predict with greater assurance what its future interest costs will be and protect itself against increases in floating rates.

The Company enters into various forward interest rate agreements to hedge against interest rate fluctuations that may occur after the Company has decided to issue long-term fixed rate debt but before the debt is actually issued. The forward interest rate agreements effectively prevent the interest rates on anticipated future long-term debt from increasing beyond a certain level, allowing the Company to predict with greater assurance what its future interest costs on fixed rate long-term debt will be.

The Company enters into commodity financial instruments to convert floating or indexed electricity and gas (and to a lesser extent oil and refined product) prices to fixed prices in order to lessen its vulnerability to reductions in electric prices for the electricity it generates, to reductions in gas prices for the gas it produces, and to increases in gas prices for the fuel it consumes in its power plants. The Company seeks to "self-hedge" its gas consumption exposure to the maximum extent with its gas production position.

The Company also routinely enters into physical commodity contracts for sales of its generated electricity and sales of its natural gas production to ensure favorable utilization of generation and production assets. Such contracts often meet the criteria of SFAS No. 133 as derivatives but are generally eligible for the normal purchase and sales exception under SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities — An Amendment of FASB Statement No. 133." For those that are not deemed normal purchases and sales, most can be designated as hedges of the underlying consumption of gas or generation of electricity.

The Company also enters into physical options for short-term periods (typically one month) to balance its short-term generating position. The options, which the Company may write or purchase, typically provide for a premium component and firm price for energy when exercised.

At the end of each quarter, the changes in fair values of derivative instruments designated as cash flow hedges are recorded in OCI for the effective portion and in current earnings, using the dollar offset method, for the ineffective portion. The changes in fair values of derivative instruments designated as fair value hedges are recorded in current earnings, as are the changes in fair values of the contracts being hedged. The changes in fair values of derivative instruments that are not designated as hedges are recorded in current earnings.

The FASB issued SFAS No. 133 Implementation Issue No. C15 dealing with a proposed electric industry normal purchases and sales exception for capacity sales transactions ("The Eligibility of Option Contracts in Electricity for the Normal Purchases and Normal Sales Exception"). As a result of Issue No. C15, as revised, the Company expects that most of its capacity sales contracts will qualify for the normal purchases and sales exception.

The table below reflects the amounts (in thousands) that are recorded as assets, liabilities and in OCI at December 31, 2001, for the Company's derivative instruments:

	Interest Rate Derivative Instruments	Currency Derivative Instruments	Commodity Derivative Instruments Net	Total Derivative Instruments
Current derivative asset	$ —	$ —	$ 763,162	$ 763,162
Long-term derivative asset	—	—	564,952	564,952
Total assets	$ —	$ —	$1,328,114	$1,328,114
Current derivative liability	$ 12,924	$ 1,911	$ 610,504	$ 625,339
Long-term derivative liability	9,535	7,580	805,733	822,848
Total liabilities	$ 22,459	$ 9,491	$1,416,237	$1,448,187
Net derivative assets (liabilities)	$(22,459)	$(9,491)	$ (88,123)	$ (120,073)
Comprehensive pre-tax gain/(loss) on cash flow hedges before reclassification adjustment	$(75,746)	$(3,752)	$ (90,901)	$ (170,399)
Reclassification adjustment for (gain)/loss included in net income	3,142	—	(132,483)	(129,341)
Total pre-tax unrealized comprehensive gain/(loss) on cash flow hedges(1)	(72,604)	(3,752)	(223,384)	(299,740)
Income tax benefit	27,170	1,515	87,678	116,363
Net comprehensive loss from derivative instruments	$(45,434)	$(2,237)	$ (135,706)	$ (183,377)

(1) Represents total pre-tax comprehensive loss from derivatives, net of amounts recognized in earnings during 2001. A reconciliation of this amount to AOCI is disclosed in Note 17.

The table above presents the aggregate amounts of derivative assets, liabilities, and OCI pertaining to derivatives as of December 31, 2001. Total pre-tax unrealized comprehensive gain (loss) on cash flow hedges represents the cumulative effect on the Company's accumulated OCI balance from pre-tax losses from effective cash flow hedges since the adoption of SFAS No. 133; it is not meant to be a measurement of losses for the twelve months ended December 31, 2001. However, because SFAS No. 133 was adopted in January 2001, the cumulative pre-tax OCI balance from effective cash flow hedges is the same as for the twelve months ended December 31, 2001.

After filing the amended Form 10-Q for Q3 2001, the Company became aware of inadvertent errors in the derivation of the "comprehensive pre-tax gain (loss) on cash flow hedges before reclassification adjustment" in the Derivative Instruments footnote to its financial statements for each of the three-month periods ended March 31, June 30 and September 30, 2001. In each case, the disclosures correctly stated the total pre-tax unrealized comprehensive gain (loss) on cash flow hedges for the periods in question, but disclosed incorrect numbers in the entries above this total. Set forth below is a table (in thousands) presenting the figures as reported and as revised.

	As Reported			Revised		
	Interest Rate Derivative Instruments	Commodity Derivative Instruments	Total Derivative Instruments	Interest Rate Derivative Instruments	Commodity Derivative Instruments	Total Derivative Instruments
YTD 9/30/01 — Footnote 8 — Derivative Instruments						
Comprehensive pre-tax gain/(loss) on cash flow hedges before reclassification adjustment	$(84,585)	$(354,011)	$(438,596)	$(84,585)	$(108,393)	$(192,978)
Reclassification adjustment for pre-tax (gain)/loss included in net income	9,085	122,809	131,894	9,085	(122,809)	(113,724)
Total pre-tax unrealized comprehensive gain/(loss) on cash flow hedges	$(75,500)	$(231,202)	$(306,702)	$(75,500)	$(231,202)	$(306,702)
YTD 6/30/01 — Footnote 3 — Derivative Instruments						
Comprehensive pre-tax gain/(loss) on cash flow hedges before reclassification adjustment	$(25,937)	$ 176,933	$ 150,996	$(25,937)	$ 220,517	$ 194,580
Reclassification adjustment for pre-tax (gain)/loss included in net income	—	21,792	21,792	—	(21,792)	(21,792)
Total pre-tax unrealized comprehensive gain/(loss) on cash flow hedges	$(25,937)	$ 198,725	$ 172,788	$(25,937)	$ 198,725	$ 172,788
YTD 3/31/01 — Footnote 2 — Summary of significant accounting principles						
Comprehensive pre-tax gain/(loss) on cash flow hedges before reclassification adjustment	$(35,898)	$ (67,330)	$(103,228)	$(35,898)	$ (33,236)	$ (69,134)
Reclassification adjustment for pre-tax (gain)/loss included in net income	—	17,047	17,047	—	(17,047)	(17,047)
Total pre-tax unrealized comprehensive gain/(loss) on cash flow hedges	$(35,898)	$ (50,283)	$ (86,181)	$(35,898)	$ (50,283)	$ (86,181)

None of the revisions presented in the table affects (positively or negatively) any of the numbers in our statement of operations, balance sheet or statement of cash flows for any of the periods in question. In particular, there is no impact on our net income, stockholders' equity or cash flow as disclosed in our quarterly unaudited financial statements.

At any point in time, it is highly unlikely that total net derivative assets and liabilities will equal cumulative pre-tax OCI from derivatives, for two primary reasons:

- *Earnings effect of these derivatives* — Only derivatives that qualify as effective cash flow hedges will have an offsetting amount recorded in OCI. Derivatives not designated as cash flow hedges and the ineffective portion of derivatives designated as cash flow hedges will be recorded into earnings instead of OCI, creating a difference between net derivative assets and liabilities and pre-tax OCI from derivatives.

- *Termination of effective cash flow hedges prior to maturity* — Following the termination of a cash flow hedge and subsequent settlement with a counterparty, the derivative asset or liability is liquidated and removed from the books. At this point, no asset or liability exists on the books for the hedge but a balance remains in OCI, which is amortized into earnings over the remaining original life of the hedge as long as it is probable that the forecasted transactions, or exposures that are being hedged, will occur. As a result, there will be a temporary difference between OCI and derivative assets and liabilities on the books until the remaining OCI balance is fully amortized into earnings.

Below is a reconciliation from the Company's net derivative assets/liabilities to its pre-tax comprehensive gain (loss) from derivative instruments at December 31, 2001, (in thousands):

Total pre-tax unrealized comprehensive gain/(loss) from derivative instruments	$(299,740)
Net derivative assets/(liabilities)	(120,073)
Difference	$ 179,667
Reconciliation:	
Pre-tax earnings impact from active derivatives not designated as cash flow hedges and ineffective portion of derivatives designated as cash flow hedges	$ 129,326
Balances in OCI with no corresponding derivative asset/liability, primarily related to effective cash flow hedges terminated prior to maturity, net of pre-tax amortization	50,341
Total reconciling items	$ 179,667

The asset and liability balances for the Company's commodity derivative instruments represent the net totals after offsetting certain assets against certain liabilities under the criteria of FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts (an Interpretation of APB Opinion No. 10 and FASB Statement No. 105)" ("FIN 39"). For a given contract, FIN 39 will allow the offsetting of assets against liabilities so long as four criteria are met: each of the two parties under contract owes the other determinable amounts; the party reporting under the offset method has the right to set-off the amount it owes against the amount owed to it by the other party; the party reporting under the offset method intends to exercise its right to set-off; and; the right of set-off is enforceable by law. The table below reflects both the amounts (in thousands) recorded as assets and liabilities by the Company and the amounts that would have been recorded had the Company's commodity derivative instrument contracts not qualified for offsetting as of December 31, 2001.

	Gross	Net
Current Derivative Asset	$3,064,900	$ 763,162
Long-Term Derivative Asset	1,671,791	564,952
Total Derivative Assets	$4,736,691	$1,328,114
Current Derivative Liability	$2,912,242	$ 610,504
Long-Term Derivative Liability	1,912,572	805,733
Total Derivative Liabilities	$4,824,814	$1,416,237
Net Derivative Liabilities	$ (88,123)	$ (88,123)

The table above excludes the value of interest rate and currency derivative instruments.

In 2001, the Company recognized gains (losses) on derivatives not designated as hedges of $98.1 million, which were recorded in electric generation and marketing revenue and $36.7 million which were recorded in fuel expense.

In 2001, the Company also recognized pre-tax gains (losses) of $(2.7) million related to hedge ineffectiveness on gas contracts, which are included in fuel expense, $(1.3) million related to hedge ineffectiveness on interest rate swap and forward interest rate agreements, which are included in other income, and $1.9 million related to hedge ineffectiveness on electricity contracts, which are included in electric generation and marketing revenue. During 2001, the Company excluded from the assessment of hedge effectiveness the extrinsic values of certain options used in costless collar arrangements to hedge its crude oil production. The Company recorded a gain of $3.0 million during 2001 associated with the extrinsic value of these options which were recorded in fuel expense. The Company excluded no components of any other derivative instruments in assessing hedge effectiveness.

During 2001, the Company's realized pre-tax commodity cash flow hedge activity contributed $132.5 million to earnings based on the reclassification adjustment from OCI to earnings. For the year ended December 31, 2001, power hedges contributed $163.2 million to earnings. At the time the power hedges were sold, the market price for electricity for the contracted delivery period was significantly higher than the market price when delivery actually occurred. For the year ended December 31, 2001, gas and crude oil hedges reduced earnings by $30.7 million. At the time the gas hedges were purchased, the market price of gas for the contracted delivery period was significantly higher than the market price when delivery actually occurred.

As of December 31, 2001, the maximum length of time over which the Company is hedging its exposure to the variability in future cash flows for forecasted transactions is 17 years. The Company estimates that pre-tax gains of $116.1 million will be reclassified from accumulated OCI into earnings during the next twelve months as the hedged transactions affect earnings assuming constant gas and power prices, interest rates, and exchange rates over time.

The table below presents (in thousands) the pre-tax gains (losses) currently held in OCI that will be amortized annually into earnings, assuming constant gas and power prices, interest rates, and exchange rates over time.

	2002	2003	2004	2005	2006	2007 & After	Total
Crude oil OCI	$ 6,534	$ —	$ —	$ —	$ —	$ —	$ 6,534
Gas OCI	(185,333)	(264,931)	(101,275)	(69,229)	(37,430)	—	(658,198)
Power OCI	316,446	93,761	4,548	5,996	7,301	228	428,280
Interest rates OCI	(19,644)	(12,099)	(8,515)	(7,723)	(7,287)	(17,336)	(72,604)
Foreign currency OCI	(1,911)	(1,661)	(1,429)	(1,263)	(1,184)	3,696	(3,752)
Total OCI	$116,092	$(184,930)	$(106,671)	$(72,219)	$(38,600)	$(13,412)	$(299,740)

20. Earnings per Share

Basic earnings per common share were computed by dividing net income by the weighted average number of common shares outstanding for the period. The dilutive effect of the potential exercise of outstanding options to purchase shares of common stock is calculated using the treasury stock method. The dilutive effect of the assumed conversion of certain convertible securities into the Company's common stock is based on the dilutive common share equivalents and the after tax distribution expense avoided upon conversion. The reconciliation of basic earnings per common share to diluted earnings per share is shown in the following table (in thousands except per share data). All share data has been adjusted to reflect the two-for-one stock splits effective October 7, 1999, June 8, 2000, and November 14, 2000.

	For the Years Ended December 31,								
	2001			2000			1999		
	Net Income	Shares	EPS	Net Income	Shares	EPS	Net Income	Shares	EPS
Basic earnings per common share:									
Income before extraordinary items and cumulative effect of a change in accounting principle	$641,062	303,522	$2.11	$373,837	281,070	$ 1.33	$107,800	225,375	$0.48
Extraordinary gain/(charge) net of (tax)/tax benefit of $(3,606), $796 and $793 for 2001, 2000, and 1999 respectively	6,007		0.02	(1,235)		—	(1,150)		(0.01)
Cumulative effect of a change in accounting principle	1,036		0.01	—		—	—		—
Net income	$648,105	303,522	$2.14	$372,602	281,070	$ 1.33	$106,650	225,375	$0.47
Common shares issuable upon exercise of stock options using treasury stock method		14,397			16,437			13,331	
Diluted earnings per common share:									
Income before dilutive effect of certain convertible securities, extraordinary items and change in accounting principle	$641,062	317,919	$2.02	$373,837	297,507	$ 1.26	$107,800	238,706	$0.45
Dilutive effect of certain convertible Securities	47,365	54,491	(0.17)	20,841	31,746	(0.06)	—	—	—
Income before extraordinary gain/(charge) and cumulative effect of a change in accounting principle	688,427	372,410	1.85	394,678	329,253	1.20	107,800	238,706	0.45
Extraordinary gain/(charge) net of (tax)/tax benefit of $(3,606), $796, and $793 for 2001, 2000, and 1999 respectively	6,007		0.02	(1,235)		(0.01)	(1,150)		—
Cumulative effect of a change in accounting principle	1,036		—	—		—	—		—
Net income, as adjusted	$695,470	372,410	$1.87	$393,443	329,253	$ 1.19	$106,650	238,706	$0.45

In December 2001 the Company recorded an extraordinary gain of $7.4 million, net of tax of $4.5 million, related to the repurchase of $122.0 million Zero Coupons, which included a pre-tax $13.1 million gain from repurchasing the Zero Coupons at a discount and a $1.2 million pre-tax loss due to the write off of unamortized deferred financing costs. The extraordinary gain was offset by extraordinary losses of $1.4 million, net of tax of $0.9 million, related to the write off of unamortized deferred financing costs resulting from the repayment of $105 million in aggregate outstanding principal amount of the 9 ¼% Senior Notes Due 2004 and the bridge facilities.

In 2000, the Company recognized a $1.2 million extraordinary loss, net of tax benefit of $0.8 million, representing the write-off of deferred financing costs related to the termination of certain financing arrangements described in Note 7.

In 1999, the Company recognized an extraordinary charge of $1.2 million, net of tax benefit of $0.8 million, representing the write-off of deferred financing costs related to non-recourse project financing for the Gilroy Power Plant. The financing agreement was terminated and the outstanding balance as of April 1999 of $120.6 million was repaid.

Unexercised employee stock options to purchase 13,294,286, 786,802 and 1,053,063 shares of the Company's common stock during the years ended December 31, 2001, 2000, and 1999, respectively, were not included in the computation of diluted shares outstanding because such inclusion would be anti-dilutive.

21. Commitments and Contingencies

Turbines. As of March 8, 2002, after turbine cancellations (see Note 24), the Company is under contract or letter of intent with certain companies to make payments for the delivery of 202 gas and steam turbines and for 35 gas and steam turbines, previously delivered in the aggregate amount of $7.3 billion. Included in the 202 turbines are 127 General Electric 7F Series turbines and equivalent. Siemens Westinghouse turbines to be delivered after March 2002.

Approximate future payments for the 237 turbines and delivery dates for the 202 turbines are as follows (in thousands):

	Future Payments	Number of Turbines
2002	$1,148,460	76
2003	629,207	15
2004	1,204,717	23
2005	1,172,483	40
2006	752,064	30
Thereafter	181,186	18
Total	$5,088,117	202

Through October 2002, the Company has the ability to cancel up to 89 turbines for a net cash payment of up to $89.0 million and a non-cash charge of $123.2 million. If these cancellations were made, the future payments would be reduced by approximately $3.1 billion.

The Company estimates that $2.5 billion will be incurred in 2002 for its construction activities including turbine payments, engineering costs and other equipment costs.

Power Plant Operating Leases — The Company has entered into long-term operating leases for cogeneration facilities and combined-cycle power generating facilities, expiring through 2049. Many of the lease agreements provide for renewal options, and some of the agreements contain customary restrictions on dividends, additional debt and further encumbrances similar to those typically found in project finance instruments. In accordance with SFAS No. 13 and SFAS No. 98, "Accounting for Leases" the Company's operating leases are not reflected on our balance sheet. Future minimum lease payments under these leases are as follows (in thousands):

	Initial Year	2002	2003	2004	2005	2006	Thereafter	Total
Watsonville	1995	$ 2,905	$ 2,905	$ 2,905	$ 2,905	$ 2,905	$ 9,874	$ 24,399
King City	1996	21,640	22,563	13,746	10,344	9,700	105,250	183,243
Greenleaf	1998	8,990	8,994	8,858	8,723	8,650	54,278	98,493
Geysers	1999	73,164	66,967	55,415	55,890	47,991	230,568	529,995
KIAC	2000	25,227	25,467	24,251	24,077	23,875	312,937	435,834
Rumford/Tiverton	2000	32,940	32,940	35,365	44,942	45,000	710,292	901,479
Pasadena	2000	31,600	131,018	26,907	27,777	27,457	483,668	728,427
South Point	2001	85,667	46,059	31,627	9,620	9,620	336,053	518,646
Broad River	2001	26,373	33,744	39,629	31,967	33,352	526,501	691,566
RockGen	2001	28,565	25,861	26,565	27,031	26,088	254,822	388,932
Total		$337,071	$396,518	$265,268	$243,276	$234,638	$3,024,243	$4,501,014

In 2001, 2000, and 1999, rent expense for cogeneration facilities operating leases amounted to $118.9 million, $69.4 million and $33.6 million, respectively. Calpine guarantees $3.0 billion of the total future minimum lease payments of its consolidated subsidiaries.

The King City operating lease commitment is supported by $88.5 million of collateral securities consisting of investment grade and U.S. Treasury securities that mature serially in amounts equal to a portion of the semi-annual lease payment.

Production Royalties and Leases — The Company is committed under numerous geothermal leases and right-of-way, easement and surface agreements. The geothermal leases generally provide for royalties based on production revenue with reductions for property taxes paid. The right-of-way, easement and surface agreements are based on flat rates and are not material. Under the terms of certain geothermal leases, prior to May 1999, when the Company consolidated the steam field and power plant operations in Lake and Sonoma Counties in northern California ("The Geysers"), royalties accrued at rates ranging from 3% to 14% of steam and effluent revenue. Following the consolidation of operations, the royalties began to accrue as a percentage of electrical revenues. Certain properties also have net profits and overriding royalty interests ranging from approximately 1% to 28%, which are in addition to the land royalties. Most lease agreements contain clauses providing for minimum lease payments to lessors if production temporarily ceases or if production falls below a specified level.

Production royalties for the years ended December 31, 2001, 2000, and 1999 are $27.5 million, $32.3 million and $13.8 million, respectively.

Office and Equipment Leases — The Company leases its corporate and regional offices as well as some of its office equipment under noncancellable operating leases expiring through 2013. Future minimum lease payments under these leases are as follows (in thousands):

2002	$ 23,532
2003	22,969
2004	25,853
2005	23,843
2006	20,152
Thereafter	94,422
Total	$210,771

Lease payments are subject to adjustments for the Company's pro rata portion of annual increases or decreases in building operating costs. In 2001, 2000, and 1999 rent expense for noncancellable operating leases amounted to $16.2 million, $6.3 million, and $4.0 million, respectively.

Natural Gas Purchases — The Company enters into gas purchase contracts of various terms with third parties to supply gas to its gas-fired cogeneration projects.

Oil & Gas Pipeline Transportation in Canada — To support production and marketing operations, Calpine has firm commitments in the ordinary course of business for gathering, processing and transmission services that require the Company to deliver certain minimum quantities of crude oil and liquids and natural gas to third parties or pay the corresponding tariffs.

Letter of Credit Facilities — In addition to the letters of credit referred to in Notes 5, 8 and 11, the Company has issued letters of credit with certain financial institutions to guarantee the Company's performance under certain long-term contracts of $125.1 million and $11.0 million as of December 31, 2001 and 2000, respectively. This brings the total outstanding letters of credit to $642.5 million and $346.9 million as of December 31, 2001 and 2000, respectively.

In August 2001 we entered into a $300 million Master Reimbursement Agreement for Letters of Credit with Credit Suisse First Boston. This facility, which was used to provide credit support to CES in connection with its trading operations, expired pursuant to its terms on December 31, 2001, and we replaced the credit support that it had provided with direct cash deposits.

Litigation

Ben Johnson vs. Peter Cartwright, et al.

On December 17, 2001, a shareholder filed a derivative lawsuit on behalf of Calpine against its directors and one of its senior officers. This lawsuit is styled *Johnson vs. Cartwright, et al.* (No. CV803872), and is pending in the California Superior Court, Santa Clara County. Calpine is a nominal defendant in this lawsuit, which alleges claims relating to purportedly misleading statements about Calpine and stock sales by certain of the director defendants and the officer defendant. Calpine has filed a demurrer asking the court to dismiss the complaint on the ground that the shareholder plaintiff lacks standing to pursue claims on behalf of Calpine. The individual defendants have filed a demurrer asking the court to dismiss the complaint on the ground that it fails to state any claims against them.

Lockport Energy Associates, L.P. and the New York Public Service Commission v. New York State Electricity and Gas Company

An action was filed against Lockport Energy Associates, L.P. and the New York Public Service Commission ("NYPSC") in August 1997 by New York State Electricity and Gas Company ("NYSEG") in the Federal District Court for the Northern District of New York. NYSEG requested the Court to direct NYPSC and FERC to modify contract rates to be paid to the Lockport Power Plant. In October 1997 NYPSC filed a cross-claim alleging that the FERC violated the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"), and the Federal Power Act by failing to reform the NYSEG contract that was previously approved by the NYPSC. On September 29, 2000, the New York Federal District Court dismissed NYSEG's complaint and NYPSC's cross-claim. The Court stated that FERC has no authority to alter or waive its regulations or exemptions to alter the terms of the applicable power purchase agreements and that Qualifying Facilities are entitled to the benefit of their bargain, even if at the expense of NYSEG and its ratepayers. On October 5, 2001, the United States Court of Appeals affirmed the judgment of the federal district court and dismissed all of the claims raised by NYSEG against Lockport.

The Company is involved in various other claims and legal actions arising out of the normal course of business. The Company does not expect that the outcome of these proceedings will have a material adverse effect on the Company's financial position or results of operations.

22. Operating Segments

The Company is first and foremost an electric generating company. In pursuing this single business strategy, it is the Company's objective to provide approximately 25% of its fuel consumption from its own natural gas production ("equity gas"). Since the Company's oil and gas production and marketing activity has reached the quantitative criteria to be considered a reportable segment under SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," the following represents reportable segments and their defining criteria. The Company's segments are electric generation and marketing; oil and gas production and marketing; and corporate and other activities. Electric generation and marketing includes the development, acquisition, ownership and operation of power production facilities, the sale of electricity and steam and electricity hedging, balancing, optimization, and trading activity. Oil and gas production includes the ownership and operation of gas fields, gathering systems and gas pipelines for internal gas consumption, third party sales and oil and gas hedging, balancing, optimization, and trading activity. Corporate activities and other consists primarily of financing activities and general and administrative costs. Certain costs related to company-wide functions are allocated to each segment. However, interest on corporate debt is maintained at Corporate and is not allocated to the segments.

The Company evaluates performance based upon several criteria including profits before tax. The accounting policies of the operating segments are the same as those described in Note 2 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies." The financial results for the Company's operating segments have been prepared on a basis consistent with the manner in which the Company's management internally disaggregates financial information for the purposes of assisting in making internal operating decisions.

Due to the integrated nature of the business segments, estimates and judgments have been made in allocating certain revenue and expense items.

	Electric Generation and Marketing	Oil and Gas Production and Marketing	Corporate, Other and Eliminations	Total
		(In thousands)		
2001				
Total Revenue	$ 6,602,240	$ 1,072,022	$ (84,284)	$ 7,589,978
Depreciation, depletion and expense	174,757	162,352	1,135	338,244
Interest expense	97,941	119,262	(51,843)	165,360
Interest income	35,681	65,314	(28,387)	72,608
Income before taxes	931,791	180,484	(125,952)	986,323
Equity income	8,763	—	—	8,763
Total assets	12,526,523	3,503,075	5,279,697	21,309,295
Property additions	6,811,838	889,391	39,231	7,740,460
Merger costs	—	41,627	—	41,627
2000				
Total Revenue	$ 2,103,729	$ 509,697	$ (66,325)	$ 2,547,101
Depreciation, depletion and expense	108,270	122,233	284	230,787
Interest expense	55,331	27,548	(8,196)	74,683
Interest income	19,026	771	20,104	39,901
Income before taxes	581,794	118,117	(61,265)	638,646
Equity income	25,928	(1,289)	—	24,639
Total assets	4,834,591	1,033,293	4,455,319	10,323,203
Property additions	4,167,551	664,911	29,238	4,861,700
1999				
Total Revenue	$ 821,191	$ 159,827	$ 2,466	$ 983,484
Depreciation, depletion and expense	60,766	56,142	17,999	134,907
Interest expense	17,048	13,381	72,819	103,248
Interest income	8,829	—	15,277	24,106
Income before taxes	259,846	19,407	(103,395)	175,858
Equity income	36,483	110	—	36,593
Total assets	2,020,146	610,684	1,770,072	4,400,902
Property additions	1,487,781	387,877	8,140	1,883,798

For the years ended December 31, 2001, 2000, and 1999, there were intersegment revenues of approximately $123.8 million, $66.5 million and $3.7 million, primarily relating to the use of internally procured gas for the Company's power plants. These intersegment revenues have been included in Total Revenue and Income before taxes in the oil and gas production and marketing reporting segment and eliminated in the corporate and other reporting segment.

Geographic Area Information

As of December 31, 2001, the Company owned interests in 59 operating power plants in the United States, one operating power plant in Canada and one operating power plant in the United Kingdom. In addition, the Company had oil and gas interests in the United States and Canada. Geographic revenue and property, plant and equipment information is based on physical location of the assets at the end of each period.

	United States	Canada	United Kingdom	Total
2001				
Total Revenue	$ 7,159,079	$ 334,834	$ 96,065	$ 7,589,978
Property, plant and equipment, net	13,355,856	1,099,780	929,354	15,384,990
2000				
Total Revenue	$ 2,254,542	$ 292,559	$ —	$ 2,547,101
Property, plant and equipment, net	7,213,444	765,716	—	7,979,160
1999				
Total Revenue	$ 847,735	$ 135,749	$ —	$ 983,484
Property, plant and equipment, net	2,912,672	363,508	—	3,276,180

23. California Power Market

California Power Market — The deregulation of the California power market has produced significant unanticipated results in the past two years. The deregulation froze the rates that utilities can charge their retail and business customers in California, until rate increases were approved by the California Public Utilities Commission ("CPUC") in 2001, and prohibited the utilities from buying power on a forward basis, while wholesale power prices were not subjected to limits.

A series of factors reduced the supply of power to California from mid 2000 through the spring 2001, which resulted in wholesale power prices for that period that were significantly higher than historical levels. Several factors contributed to this increase. These included:

- significantly increased volatility in prices and supplies of natural gas;
- an unusually dry fall and winter in the Pacific Northwest during 2000, which reduced the amount of available hydroelectric power from that region (typically, California imports a portion of its power from this source);
- the large number of power generating facilities in California nearing the end of their useful lives, resulting in increased downtime (either for repairs or because they had exhausted their air pollution credits and replacement credits had become too costly to acquire on the secondary market); and
- continued obstacles to new power plant construction in California, which deprived the market of new power sources that could have, in part, ameliorated the adverse effects of the foregoing factors.

During the period of higher wholesale prices, there was significant under-recovery of costs by two of the major California utilities. As a consequence, these two utilities defaulted under a variety of contractual obligations, including payment obligations to power generators. PG&E defaulted on payment obligations to the Company under its long-term QF contracts, which are subject to federal regulation under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). The PG&E QF contracts are in place at eleven of the Company's facilities and represent nearly 600 megawatts of electricity for Northern California customers.

Commencing in the second half of 2001, the supply/demand imbalance for electric power has been substantially reduced in the short term, resulting in significantly lower power prices than were seen in the earlier part of the year. These reductions may be attributed to milder than expected summer and fall in California and the western United States, a reduction in the demand for power as a result of the economic downturn in the region and greater consumer conservation, changes in the power market, including a greater portion of power sold on a long-term, forward basis, than on a short-term spot basis, reduction in natural gas prices, and the introduction of new supplies of power.

PG&E Bankruptcy Proceedings — On April 6, 2001, PG&E filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. As of April 6, 2001, the Company had recorded approximately $265.6 million in accounts receivable with PG&E under the QF contracts, plus $68.7 million in notes receivable not yet due and payable. Since April 6, 2001, PG&E has made payment for capacity and energy deliveries under the QF contracts. On July 6, 2001, the Company announced that it had entered into a binding agreement with PG&E to modify all of its QF contracts with PG&E and that, based upon such modification, PG&E had agreed to assume all of the QF contracts. Under the terms of this agreement, the Company continues to receive its contractual capacity payments under the QF contracts, plus a five-year fixed energy price component that averages 5.37 cents per kilowatt-hour in lieu of the short run avoided cost. In addition, all past due receivables under the QF contracts were elevated to administrative priority status in the PG&E bankruptcy proceeding to be paid to the Company, with interest, upon the effective date of a confirmed plan of reorganization. Administrative claims enjoy priority over payments made to the general unsecured creditors in bankruptcy. The bankruptcy court approved the agreement on July 12, 2001. On December 6, 2001, Calpine and PG&E executed a supplement agreement to the July 6, 2001, agreement whereby PG&E agreed to commence paying Calpine all pre-petition receivables due under the QF contracts with interest at a rate of 5% per annum. The payments were scheduled to be made in twelve monthly installments with the first payment of principal made on December 31, 2001, including all accrued interest from the initial default dates, and the last payment of principal and interest on November 30, 2002. In the event that the effective date of a confirmed plan of reorganization occurs sooner than the payment dates, PG&E is required to make all payments owed to Calpine, including interest thereon accruing at 5%, as of such effective date. However, under the terms of the supplemental agreement, PG&E's obligation to make such payments is separate from and not dependent upon the confirmation of a plan of reorganization. The bankruptcy court approved the supplemental agreement on December 21, 2001. There has been no final plan of reorganization approved by the bankruptcy court. After receiving the first of twelve payments, including accrued interest through December 31, 2001, the Company sold the remaining receivable on December 31, 2001, for 96.125% of its face value.

CPUC Proceeding Regarding QF Contract Pricing for Past Periods — The Company's QF contracts with PG&E provide that the CPUC has the authority to determine the appropriate utility "avoided cost" to be used to set energy payments for certain QF contracts by determining the short run avoided cost ("SRAC") energy price formula. In mid 2000, the Company's QF facilities elected the option set forth in Section 390 of the California Public Utility Code, which provides QFs the right to elect to receive energy payments based on the California Power Exchange ("PX") market clearing price instead of the price determined by SRAC. Having elected such option, Calpine was paid based upon the PX zonal day ahead clearing price ("PX Price") from summer 2000 until January 19, 2001, when the PX ceased operating a day ahead market. The CPUC has conducted proceedings (R.99-11-022) to determine whether the PX Price was the appropriate price for the energy component upon which to base payments to QFs which had elected the PX-based pricing option. The CPUC at one point issued a proposed decision to the effect that the PX Price was the appropriate price for energy payments under the California Public Utility Code but tabled it and a final decision has not been issued to date. Therefore, it is possible that the CPUC could order a payment adjustment based on a different energy price determination. The Company believes that the PX Price was the appropriate price for energy payments but there can be no assurance that this will be the outcome of the CPUC proceedings.

Current California QF Contract Pricing — When the PX ceased operation on January 19, 2001, the CPUC ordered that the QFs that had previously switched to the PX Price be switched back to the applicable

SRAC energy price formula. On June 14, 2001, however, the CPUC issued an order (Decision 01-06-015) (the "June 2001 Decision") that authorized the California utilities, including PG&E, to amend QF contracts to elect a fixed energy price component that averages 5.37 cents per kilowatt-hour for a five-year term under those contracts in lieu of using the SRAC energy price formula. By this order, the CPUC authorized the QF contract energy price amendments without further CPUC concurrence. As part of the agreement the Company entered into with PG&E pursuant to which PG&E, in bankruptcy, agreed to assume its QF contracts with Calpine, PG&E agreed with Calpine to amend these contracts to adopt the fixed price component that averages 5.37 cents pursuant to the June 2001 Decision. This election became effective as of July 16, 2001. As a result of the June 2001 Decision and the Company's agreement with PG&E to amend the QF contracts to adopt the fixed price energy component, the energy price component in the Company's QF contracts is now fixed for five years. As of July 1, 2006, the energy payment under the QF contracts with PG&E will be determined by the CPUC in accordance with its determination of the SRAC energy price formula.

California Long-Term Supply Contracts — California has adopted legislation permitting it to issue long-term revenue bonds to provide funding for wholesale purchases of power. The bonds will be repaid with the proceeds of payments by retail customers over time. The California Department of Water Resources ("DWR") sought bids for long-term power supply contracts in a publicly announced auction. Calpine successfully bid in that auction and signed several long-term power supply contracts with DWR.

On February 7, 2001, the Company announced the signing of a 10-year, $4.6 billion fixed price contract with DWR to provide electricity to the State of California. The Company committed to sell up to 1,000 megawatts of electricity, with initial deliveries of 200 megawatts starting October 1, 2001, which increases to 1,000 megawatts by January 1, 2004. The electricity will be sold directly to DWR on a 24 hours-a-day, 7 days-a-week basis.

On February 28, 2001, the Company announced the signing of two long-term power sales contracts with DWR. Under the terms of the first contract, a 10-year, $5.2 billion fixed price contract, the Company committed to sell up to 1,000 megawatts of generation. Initial deliveries began July 1, 2001, with 200 megawatts and increase to 1,000 megawatts by as early as July 2002. Under the terms of the second contract, a 20-year contract totaling up to $3.1 billion, the Company will supply DWR with up to 495 megawatts of peaking generation, beginning with 90 megawatts in August 2001 and increasing up to 495 megawatts as early as August 2002.

On June 11, 2001, the Company announced the signing of a three-year peaking contract to supply DWR with up to 225 megawatts of peaking generation beginning in the summer of 2002 through April 30, 2005, from the Los Esteros Critical Energy Facility currently under development in San Jose, California. In the event that the Los Esteros Critical Energy Facility has not achieved commercial operation by October 1, 2002, DWR would have the right to terminate the contract.

On December 11, 2001, the Company announced that it was meeting with officials from the State of California at their request to discuss whether, and if so how, the long-term contracts with DWR could be modified. No definitive modifications have been agreed to and the discussions have been ongoing.

However, we currently have a dispute with DWR concerning payment of the capacity payment on the 495-megawatt Peaking Contract dated February 28, 2001. The contract provides that CES may earn a capacity payment by committing to supply electricity to DWR from a source other than the peaker units designated in the contract either through substitution of those designated units or by providing replacement energy. DWR has made certain assertions challenging CES' right to substitute units or provide replacement energy and has withheld capacity payments in the amount of $9.5 million since December 2001. The resolution of this dispute is part of the ongoing discussions regarding modifications to the contracts.

On February 25, 2002, both the CPUC and the California Electric Oversight Board each filed complaints under Section 206 of the Federal Power Act with the FERC (EL02-60-000 and EL02-62-000, respectively) alleging that the prices and terms of the long-term contracts with DWR are unjust and unreasonable and counter to the public interest. The Company is a respondent and the four long-term contracts entered into by the Company are subject to the complaint. The FERC has noticed this proceeding and responsive filings were due from the respondents on or before March 22, 2002. Calpine believes that the complaints are without merit and intends to defend its position vigorously.

On March 6, 2002, in accordance with the state legislation that authorized DWR to enter into the long-term power contracts, the CPUC issued a Rate Agreement, which dedicates a portion of the retail rate paid by electricity customers of the California investor-owned utilities to a fund to pay bondholders of bonds to be issued by DWR and to a fund to pay electricity suppliers such as Calpine. The proceeds from those bonds will be used in part to fund the Electric Power Fund established by the state legislation authorizing DWR to enter into long-term power contracts with the power suppliers whose recourse in the event of a default by DWR is to the Electric Power Fund. Proceeds from the bonds will also be used to repay the state of California General Fund. The bonds have not been issued, but representatives of the State have indicated that the bonds should be issued in the near future.

FERC Investigation into California Wholesale Markets. In August 2000 FERC initiated an investigation of the California power markets. In November 2000 FERC found that the California power market structure and market rules were seriously flawed, and that these flaws, together with short supply relative to demand, resulted in unusually high energy prices. FERC proposed specific remedies to the identified market flaws that included the potential refund of rates charged for service determined by FERC not to be just and reasonable.

Through a series of orders most recently culminating in its order of December 19, 2001, FERC has prescribed a methodology for determining potential refunds in the California wholesale electric markets. The key elements of this methodology are:

- the refund period runs from October 2, 2000, through June 19, 2001.
- the only sales subject to price mitigation and potential refund are spot market transactions (sales entered into 24 hours or less in advance of the delivery of power).
- the methodology for determining refunds is based upon the costs associated with the least efficient generating unit needed to meet system requirements during any relevant pricing interval.
- any refunds calculated under this methodology are to be offset by amounts owed to the seller from various entities purchasing power in California.
- actual application of the methodology and calculations of any refunds remain subject to ongoing proceedings before the FERC which are scheduled to conclude during the latter half of 2002.

The scope of the ongoing FERC investigation is limited to spot market sales made to the ISO and PX during the October 2, 2000, to June 19, 2001, time period, and so Calpine's forward long-term contracts (including its QF contracts) are not subject to this investigation. Due to the ongoing nature of this investigation and ambiguities concerning how the refund methodology is to be applied, it is not possible at this time to predict the amount of any potential refunds that Calpine ultimately may be required to pay. However, based on the information available at this time, we do not believe that the proceeding will result in a material adverse effect on our financial conditions or results of operations. It also should be noted that all of FERC orders issued in these proceedings to date are subject to judicial review sought by various parties. The outcome of these judicial proceedings cannot be determined at this time.

On June 19, 2001, FERC ordered price mitigation in 11 states in the western United States in an attempt to reduce the dependence of the California market on spot markets in favor of longer-term committed energy supplies. The order provides for price mitigation in the spot market throughout the 11 state western region during "reserve deficiency hours," which is when operating reserves in California fall below seven percent. This price will be a single market clearing price based upon the marginal operating cost of the last unit dispatched by the California ISO. In addition, FERC implemented price mitigation in non-reserve deficiency hours, which will be set at 85% of the market clearing price during the last reserve deficiency period. These price mitigation procedures went into effect on June 20, 2001, and will remain in effect until September 30, 2002.

The retention by FERC of a market-based, rather than a cost-of-service-based, rate structure will enable the Company to continue to realize benefits from its efficient, modern power plants. The Company believes that its marginal costs will continue to be below any price cap imposed by FERC, whether during reserve deficiency hours or at other times. Therefore, the Company believes that FERC's mitigation plan will not have a material adverse effect on its financial condition or results of operations.

FERC also ordered all sellers and buyers in wholesale power markets administered by the California ISO, as well as representatives of the State of California, to participate in a settlement conference before a FERC administrative law judge. The settlement discussions were intended to resolve all issues that remain outstanding to resolve past accounts, including sellers' claims for unpaid invoices, and buyers' claims for refunds of alleged overcharges, for past periods. The settlement discussions began on June 25, 2001, and ended on July 9, 2001. The Chief Administrative Law Judge issued his report and recommendations to FERC on July 12, 2001. On July 25, 2001, FERC ordered an expedited fact-finding hearing to calculate refunds for spot market transactions in California. The hearing has been delayed pending the submission by the California ISO and the PX of data for the purpose of developing the factual basis needed to implement the refund methodology and order refunds, and at this time it is not possible to determine when the proceeding will conclude. While it is not possible to predict the amount of any refunds until the hearings take place, based upon the information available at this time, the Company does not believe that this proceeding will result in a material adverse effect on the Company's financial condition or results of operations.

On February 13, 2002, FERC initiated an investigation of potential manipulation of electric and natural gas prices in the western United States. This investigation was initiated as a result of allegations that Enron Corp. through its affiliates used its market position to distort electric and natural gas markets in the West. The scope of the investigation is to consider whether, as a result of any manipulation in the short-term markets for electric energy or natural gas or other undue influence on the wholesale markets by any party since January 1, 2000, the rates of the long-term contracts subsequently entered into in the West are potentially unjust and unreasonable. FERC has stated that it may use the information gathered in connection with the investigation to determine how to proceed on any existing or future complaint brought under Section 206 of the Federal Power Act involving long-term power contracts entered into in the West since January 1, 2000, or to initiate a Federal Power Act Section 206 or Natural Gas Act Section 5 proceeding on its own initiative.

24. Subsequent Events

Following a comprehensive review of our power plant development program, the Company recently announced the adoption of a revised capital expenditure program, which contemplates the completion of 27 power projects (representing 15,200 MW) currently under construction during 2002 and 2003. Three of these projects have subsequently achieved full or partial commercial operations (the Magic Valley Generating Center, the Gilroy Peaking Energy Center and the Aries Power Project). Construction of an additional 34 advanced-stage development projects (representing 15,100 MW) will be placed on hold following completion of advanced development activities pending further review, reducing previously forecasted 2002 capital spending by as much as $2 billion. Construction of these advanced stage development projects is expected to proceed when there is an established marked need for additional generating resources at prices that will allow the Company to meet its established investment criteria, and when capital is available to us on attractive terms. Moreover, our entire development and construction program is flexible and subject to continuing review and revision based upon such criteria.

Between January 2, 2002, and February 11, 2002, the Company repurchased an additional $192.5 million of its Zero Coupons, bringing total repurchases to $314.5 million, and bringing the amount of Zero Coupons that remain outstanding to $685.5 million.

On January 3, 2002, the Company completed an offering of $100 million in aggregate principal amount of 4% Convertible Senior Notes Due 2006, pursuant to the partial exercise of the initial purchaser's $200 million option to purchase additional Convertible Senior Notes. These securities will be convertible into shares of Calpine common stock at a price of $18.07. The proceeds from the offerings will be used for general corporate purposes.

The Company recently met with representatives of the State of California, DWR, the CPUC and their advisors to discuss the status of long-term supply contracts signed in 2001. We believe that these contracts are enforceable as written. However, the Company is always willing to discuss with its customers proposals to restructure or otherwise modify existing contracts to address concerns of its customers if the Company can do so without adversely affecting its interests.

In February 2002, both the California Public Utilities Commission and the California Electric Oversight Board filed complaints under Section 206 of the Federal Power Act with the Federal Energy Regulatory Commission (FERC) (EL02-60-000 and EL02-62-000, respectively) alleging that the prices and terms of Services, L.P. (CES) is a respondent and the four long-term contracts entered into between CES and DWR are subject to the complaint. *(see Note 23)* The FERC has noticed this proceeding and responsive pleadings were due from the respondents on or before March 22, 2002. Calpine believes that the complaints are without merit and intends to defend its position vigorously.

On February 13, 2002, FERC initiated an investigation of potential manipulation of electric and natural gas prices in the western United States. This investigation was initiated as a result of allegations that Enron Corp. through its affiliates used its market position to distort electric and natural gas markets in the West. The scope of the investigation is to consider whether as a result of any manipulation in the short-term markets for electric energy or natural gas or other undue influence on the wholesale markets by any party since January 1, 2000, that the rates of the long-term contracts subsequently entered into in the West are potentially unjust and unreasonable. FERC has stated that it may use the information gathered in connection with the investigation to determine how to proceed on any existing or future complaint brought under Section 206 of the Federal Power Act involving long-term power contracts entered into in the West since January 1, 2000, or to initiate a Federal Power Act Section 206 or Natural Gas Act Section 5 proceeding on its own initiate.

On February 25, 2002, both the CPUC and the California Electric Oversight Board ("EOB") each filed complaints under Section 206 of the Federal Power Act with the FERC (EL02-60-000 and EL02-62-000, respectively) alleging that the prices and terms of the long-term contracts with DWR are unjust and unreasonable and counter to the public interest. Calpine is a respondent and the four long-term contracts entered into by Calpine are subject to the complaint. The FERC has noticed this proceeding and responsive filings are due from the respondents on or before March 22, 2002. Calpine believes that the complaints are without merit and intends to defend its position vigorously.

On March 6, 2002, in accordance with the state legislation that authorized DWR to enter into the long-term power contracts, the CPUC issued a Rate Agreement, which dedicates a portion of the retail rate paid by electricity customers of the California investor owned utilities to a fund to pay bondholders of bonds to be issued by DWR and to a fund to pay electricity suppliers such as Calpine. The proceeds from those bonds will be used in part to fund the Electric Power Fund established by the state legislation authorizing DWR to enter into long-term power contracts with the power suppliers whose recourse in the event of a default by DWR is to the Electric Power Fund. Proceeds from the bonds will also be used to repay the state of California General Fund. The bonds have not been issued, but representatives of the State have indicated that the bonds should be issued in the near future.

On March 12, 2002 the Company announced that it had closed a new $1.6-billion secured credit facility. The $1.6 billion includes a new $1.0-billion revolving credit facility expiring on May 24, 2003, and a new two-year $600 million loan that will be available upon satisfaction of certain conditions. The Company also amended the $400 million revolving credit facility. The security for these facilities includes Calpine's interests in its natural gas properties, the Saltend power plant in the U.K. and Calpine's equity investment in nine U.S. power plants. The proceeds of the borrowings will be used to finance Calpine's capital expenditures and, subject to the limits of Calpine's existing bond indentures, for other general corporate purposes. The banks in the new credit facility are The Bank of Nova Scotia, Citibank, Bank of America, Bayerische Landesbank Girozentrale, Credit Suisse First Boston, Deutsche Bank, The Toronto-Dominion Bank and ING Barings.

On March 12, 2002, the Company announced a new turbine program that reduces previously forecasted capital spending by approximately $1.2 billion in 2002 and $1.8 billion in 2003. The revision includes adjusted timing of turbine delivery and related payment schedules and also cancellation orders. As a result of the cancellation, the Company will record a pre-tax charge of $161 million in the first quarter of 2002, which includes financing costs to date.

In March 2002, the Company repaid the Michael Petroleum note payable, which had a balance of $64.8 million at December 31, 2001.

In March 2002, the Company became aware that certain emission reduction credits that were to be purchased through a broker were not available. The Company purchases such credits for the purpose of obtaining environmental permits to build new power plants. The Company is aggressively pursuing recovery of this loss and has filed civil suit against the broker. In connection with this issue, the Company recorded a $17.7 million reserve for this amount, which is reflected in the financial results for the year ended December 31, 2001. See Note 21 for a further discussion of this matter.

Calpine Corporation v. Automated Credit Exchange ("ACE"). On March 5, 2002, Calpine sued ACE in the Superior Court of the State of California for the County of Alameda for negligence and breach of contract to recover reclaim trading credits, a form of emission reduction credits that should have been held in Calpine's account with U.S. Trust Company (US Trust). ACE is a broker in emission reduction credits based in Pasadena, California. Calpine had paid ACE for Nitrogen oxide (NOx) coastal credits that were to be purchased by ACE and held by US Trust. The credits were to be held by US Trust pursuant to a Credit Holding Agreement, which provided, among other things, that US Trust was to hold the credits until receiving instructions from ACE to disburse the credits. ACE had agreed that (i) upon prior written instruction from Calpine, to instruct US Trust to take such actions as may be directed by Calpine to disburse the credits held in escrow pursuant to the Credit Holding Agreement and (ii) not to take any action, or otherwise instruct US Trust to take any action, concerning the credits held in escrow pursuant to the Credit Holding Agreement without prior written instruction from Calpine.

Securities Class Action Lawsuits. Over the past several weeks, five similar or identical shareholder lawsuits have been filed against Calpine and certain of its officers in the United States District Court, Northern District of California. The action captioned *Weisz vs. Calpine Corp., et al.*, filed March 11, 2002, is a purported class action on behalf of purchasers of Calpine stock between March 15, 2001 and December 13, 2001. The four other actions, captioned *Local 144 Nursing Home Pension Fund vs. Calpine Corp., Lukowski vs. Calpine Corp., Hart vs. Calpine Corp.,* and *Atchison vs. Calpine Corp.*, were filed between March 18, 2002 and March 26, 2002. The complaints in these four actions are virtually identical, and each was filed by the same law firm, in conjunction with other law firms as co-counsel. All four lawsuits are purported class actions on behalf of purchasers of Calpine's securities between January 5, 2001 and December 13, 2001.

The complaints in these five actions allege that, during the purported class periods, certain senior executives issued false and misleading statements about Calpine's financial condition in violation of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, as well as Rule 10b-5. These actions seek an unspecified amount of damages, in addition to other forms of relief. The Company expects that these actions, as well as any related actions that may be filed in the future, will be consolidated by the court into a single securities class action. The Company considers the lawsuits to be without merit, and the Company intends to defend vigorously against these allegations.

25. Quarterly Consolidated Financial Data (unaudited)

The Company's quarterly operating results have fluctuated in the past and may continue to do so in the future as a result of a number of factors, including, but not limited to, the timing and size of acquisitions, the completion of development projects, the timing and amount of curtailment of operations under the terms of certain power sales agreements, the degree of risk management and trading activity, and variations in levels of production. Furthermore, the majority of the dollar value of capacity payments under certain of the Company's power sales agreements are received during the months of May through October.

The Company's common stock has been traded on the New York Stock Exchange since September 19, 1996. There were 1,085 common stockholders of record at December 31, 2001. No dividends were paid for the years ended December 31, 2001 and 2000. All share data has been adjusted to reflect the two-for-one stock split effective June 8, 2000, and the two-for-one stock split effective November 14, 2000.

	Quarter Ended			
	December 31,	September 30,	June 30,	March 31,
	(In thousands, except per share amounts)			
2001				
Total revenue	$1,721,249	$2,916,105	$1,612,873	$1,339,751
Gross profit	215,836	535,891	304,225	275,568
Income from operations	164,192	501,138	213,710	217,623
Income before extraordinary gain/(charge) and cumulative effect of a change in accounting principle	92,671	320,799	108,965	118,627
Extraordinary gain/(charge), net of tax	7,307	—	(1,300)	—
Cumulative effect of a change in accounting principle	—	—	—	1,036
Net income	$ 99,978	$ 320,799	$ 107,665	$ 119,663
Basic earnings per common share:				
Income before extraordinary gain/(charge) and cumulative effect of a change in accounting principle	$ 0.30	$ 1.05	$ 0.36	$ 0.40
Extraordinary gain/(charge)	0.03	—	—	—
Cumulative effect of a change in accounting principle	—	—	—	—
Net income	0.33	1.05	0.36	0.40

	Quarter Ended			
	December 31,	September 30,	June 30,	March 31,
	(In thousands, except per share amounts)			
Diluted earnings per common share:				
Income before dilutive effect of certain convertible securities, extraordinary gain/(charge) and cumulative effect of a change in accounting principle	$ 0.29	$ 1.01	$ 0.34	$ 0.38
Dilutive effect of certain convertible securities	(0.01)	(0.13)	(0.02)	(0.02)
Income before extraordinary gain/(charge) and cumulative effect of a change in accounting principle	0.28	0.88	0.32	0.36
Extraordinary gain/(charge)	0.02	—	—	—
Cumulative effect of a change in accounting principle	—	—	—	—
Net income	0.30	0.88	0.32	0.36
Common stock price per share:				
High	$ 28.85	$ 46.00	$ 57.35	$ 58.04
Low	10.00	18.90	36.20	29.00
2000				
Total revenue	$1,099,934	$ 744,814	$ 417,155	$ 285,198
Gross profit	302,927	326,259	146,632	71,150
Income from operations	245,188	292,021	122,896	56,756
Income before extraordinary charge	134,683	158,545	59,508	21,101
Extraordinary charge	—	1,235	—	—
Net income	$ 134,683	$ 157,310	$ 59,508	$ 21,101
Basic earnings per common share:				
Income before extraordinary charge	$ 0.45	$ 0.56	$ 0.22	$ 0.08
Extraordinary charge	—	(0.01)	—	—
Net income	0.45	0.55	0.22	0.08
Diluted earnings per common share:				
Income before extraordinary charge and dilutive effect of certain trust preferred securities	$ 0.43	$ 0.52	$ 0.21	$ 0.07
Dilutive effect of certain trust preferred securities	(0.03)	(0.03)	(0.01)	—
Income before extraordinary charge	0.40	0.49	0.20	0.07
Extraordinary charge	—	(0.01)	—	—
Net income	0.40	0.48	0.20	0.07
Common stock price per share:				
High	$ 52.97	$ 52.25	$ 35.22	$ 30.75
Low	32.25	32.25	18.13	16.09

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS ON SCHEDULE

To the Board of Directors
and Stockholders of Calpine Corporation:

We have audited, in accordance with generally accepted auditing standards in the United States, the consolidated financial statements of Calpine Corporation included in this Annual Report on Form 10-K and have issued our report thereon dated February 6, 2002 (except for Note 24 as to which the date is March 22, 2002). Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule listed in the accompanying index is the responsibility of the Company's management, is presented for the purposes of complying with the Securities and Exchange Commission's rules, and is not part of the basic financial statements. The schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic consolidated financial statements taken as a whole.

/s/ Arthur Andersen LLP

San Jose, California
March 22, 2002

SCHEDULE II

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Year	Charged to Expense	Reserved Gain	Reductions(1)	Balance at End of Year
			(In thousands)		
Year Ended December 31, 2001					
Allowance for Doubtful Accounts	$11,555	$11,539	$ —	$(7,672)	$15,422
Reserve for Notes Receivable	4,513	—	—	(2,920)	1,593
Gain reserved on certain Enron transactions	—	—	13,091	—	13,091
Reserve for third-party default on emission reduction credits	—	17,677	—	—	17,677
Year Ended December 31, 2000					
Allowance for Doubtful Accounts	$ 3,646	$13,454	$ —	$(5,545)	$11,555
Reserve for Notes Receivable	—	4,513	—	—	4,513
Year Ended December 31, 1999					
Allowance for Doubtful Accounts	$ 634	$ 3,105	$ —	$ (93)	$ 3,646

(1) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

SUPPLEMENTAL OIL AND GAS DISCLOSURES
(Unaudited)

Oil and Gas Producing Activities

The following disclosures for Calpine Corporation ("the Company") are made in accordance with Statement of Financial Accounting Standards (SFAS) No. 69, "Disclosures About Oil and Gas Producing Activities (An Amendment of FASB Statements 19, 25, 33 and 39)". Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves represent estimated quantities of natural gas and crude oil that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made.

Proved developed reserves are proved reserves expected to be recovered, through wells and equipment in place and under operating methods being utilized at the time the estimates were made.

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Estimates of proved and proved developed reserves as of December 31, 2001, were based on estimates made by Netherland, Sewell & Associates Inc. (NS&A), independent petroleum consultants, for reserves in the United States; and Gilbert Laustsen Jung Associates, Ltd. (GLJA) independent petroleum consultants, for reserves in Canada.

Estimates of proved and proved developed reserves as of December 31, 2000 and 1999, were based on estimates made by Netherland, Sewell & Associates Inc. (NS&A), independent petroleum consultants, for reserves in the United States; and Gilbert Laustsen Jung Associates, Ltd. (GLJA), and McDaniel & Associates Consultants, Ltd., both independent petroleum consultants, for reserves in Canada.

Market prices as of each year-end were used for future sales of natural gas and crude oil. Future operating costs, production and ad valorem taxes and capital costs were based on current costs as of each year-end, with no escalation. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. Reserve data represent estimates only and should not be construed as being exact. Moreover, the standardized measure should not be construed as the current market value of the proved oil and gas reserves or the costs that would be incurred to obtain equivalent reserves. A market value determination would include many additional factors including (a) anticipated future changes in natural gas and crude oil prices, production and development costs, (b) an allowance for return on investment, (c) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities, and (d) other business risk.

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table sets forth the capitalized costs relating to the Company's natural gas and crude oil producing activities (excluding pipeline and related assets) at December 31, 2001 and 2000, (in thousands):

	2001	2000
Proved properties	$1,913,025	$1,331,572
Unproved properties	322,735	76,075
Total	2,235,760	1,407,647
Less- Accumulated depreciation, depletion and amortization	(519,747)	(338,475)
Net capitalized costs	$1,716,013	$1,069,172

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

The acquisition, exploration and development costs disclosed in the following tables are in accordance with definitions in SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include exploration expenses and additions to exploration wells, including those in progress. Development costs include additions to production facilities and equipment, as well as additions to development wells, including those in progress. The following table sets forth costs incurred related to the Company's oil and gas activities for the years ended December 31, 2001, 2000, and 1999, (in thousands):

	United States	Canada	Total
December 31, 2001			
Acquisition costs of properties —			
Proved	$342,941	$ 6,762	$349,703
Unproved	234,789	17,780	252,569
Subtotal	577,730	24,542	602,272
Exploration costs	20,495	17,970	38,465
Development costs	86,311	162,343	248,654
Total	$684,536	$204,855	$889,391
December 31, 2000 —			
Acquisition costs of properties-			
Proved	$103,140	$307,356	$410,496
Unproved	1,119	71,141	72,260
Subtotal	104,259	378,497	482,756
Exploration costs	3,177	62,469	65,646
Development costs	25,689	90,820	116,509
Total	$133,125	$531,786	$664,911
December 31, 1999 —			
Acquisition costs of properties-			
Proved	$216,242	$ 27,900	$244,142
Unproved	—	6,000	6,000
Subtotal	216,242	33,900	250,142
Exploration costs	2,860	52,100	54,960
Development costs	975	81,800	82,775
Total	$220,077	$167,800	$387,877

Results of Operations for Oil and Gas Producing Activities

The following table sets forth results of operations for oil and gas producing activities (excluding pipeline and related operations) for the years ended December 31, 2001, 2000, and 1999 (in thousands):

	United States	Canada	Total
December 31, 2001-			
Oil and gas production revenues-			
Third-party	$ 96,788	$330,420	$427,208
Intercompany	113,584	3,730	117,314
Total revenues	210,372	334,150	544,522
Exploration expenses, including dry hole	4,314	12,503	16,817
Production costs	29,250	60,792	90,042
Depreciation, depletion and amortization	59,819	101,265	161,084
Income before income taxes	116,989	159,590	276,579
Income tax provision	41,997	76,061	118,058
Results of operations	$ 74,992	$ 83,529	$158,521
December 31, 2000-			
Oil and gas production revenues-			
Third-party	$ 42,685	$308,359	$351,044
Intercompany	62,809	—	62,809
Total revenues	105,494	308,359	413,853
Exploration expenses, including dry hole	1,836	22,148	23,984
Production costs	14,895	49,157	64,052
Depreciation, depletion and amortization	30,969	87,271	118,240
Income before income taxes	57,794	149,783	207,577
Income tax provision	22,540	68,612	91,152
Results of operations	$ 35,254	$ 81,171	$116,425
December 31, 1999-			
Oil and gas production revenues-			
Third-party	$ 5,299	$140,600	$145,899
Intercompany	3,734	—	3,734
Total revenues	9,033	140,600	149,633
Exploration expenses, including dry hole	278	13,100	13,378
Production costs	1,693	37,600	39,293
Depreciation, depletion and amortization	4,047	52,100	56,147
Income before income taxes	3,015	37,800	40,815
Income tax provision	1,176	15,100	16,276
Results of operations	$ 1,839	$ 22,700	$ 24,539

The results of operations for oil and gas producing activities exclude interest charges and general corporate expenses.

Net Proved and Proved Developed Reserve Summary

The following table sets forth the Company's net proved and proved developed reserves at December 31 for each of the three years in the period ended December 31, 2001, and the changes in the net proved reserves for each of the three years in the period then ended as estimated by the independent petroleum consultants.

	United States	Canada	Total
Natural gas (Bcf) (1)-			
Net proved reserves at December 31, 1998	9	376	385
Revisions of previous estimates	(5)	(16)	(21)
Purchases in place	212	21	233
Extensions, discoveries and other additions	—	109	109
Sales in place	—	(5)	(5)
Production	(3)	(46)	(49)
Net proved reserves at December 31, 1999	213	439	652
Revisions of previous estimates	28	(66)	(38)
Purchases in place	97	148	245
Extensions, discoveries and other additions	21	78	99
Sales in place	(1)	(10)	(11)
Production	(25)	(52)	(77)
Net proved reserves at December 31, 2000	333	537	870
Revisions of previous estimates	(24)	(49)	(73)
Purchases in place	208	—	208
Extensions, discoveries and other additions	125	31	156
Sales in place	(11)	(13)	(24)
Production	(41)	(61)	(102)
Net proved reserves at December 31, 2001	590	445	1,035

	United States	Canada	Total
Natural gas liquids and crude oil (MBbl) (2) (3)-			
Net proved reserves at December 31, 1998	—	27,100	27,100
Revisions of previous estimates	—	600	600
Purchases in place	1,895	1,200	3,095
Extensions, discoveries and other additions	—	6,000	6,000
Sales in place	—	(600)	(600)
Production	(35)	(3,900)	(3,935)
Net proved reserves at December 31, 1999	1,860	30,400	32,260
Revisions of previous estimates	89	(170)	(81)
Purchases in place	1,732	14,133	15,865
Extensions, discoveries and other additions	108	7,600	7,708
Sales in place	(10)	(100)	(110)
Production	(240)	(5,202)	(5,442)
Net proved reserves at December 31, 2000	3,539	46,661	50,200
Revisions of previous estimates	(238)	(1,492)	(1,730)
Purchases in place	1,116	450	1,566
Extensions, discoveries and other additions	671	2,243	2,914
Sales in place	(80)	(3,054)	(3,134)
Production	(434)	(6,192)	(6,626)
Net proved reserves at December 31, 2001	4,574	38,616	43,190
(Bcfe) (1) equivalent (4)-			
Net proved reserves at December 31, 1998	9	539	548
Revisions of previous estimates	(6)	(13)	(19)
Purchases in place	224	28	252
Extensions, discoveries and other additions	—	145	145
Sales in place	—	(9)	(9)
Production	(3)	(69)	(72)
Net proved reserves at December 31, 1999	224	621	845
Revisions of previous estimates	29	(67)	(38)
Purchases in place	108	233	341
Extensions, discoveries and other additions	22	124	146
Sales in place	(1)	(11)	(12)
Production	(27)	(84)	(111)
Net proved reserves at December 31, 2000	355	816	1,171
Revisions of previous estimates	(25)	(58)	(83)
Purchases in place	214	3	217
Extensions, discoveries and other additions	129	45	174
Sales in place	(12)	(32)	(44)
Production	(44)	(97)	(141)
Net proved reserves at December 31, 2001	617	677	1,294

	United States	Canada	Total
Net proved developed reserves			
Natural gas (Bcf) (1)			
December 31, 1999	193	315	508
December 31, 2000	268	391	659
December 31, 2001	378	394	772
Natural gas liquids and crude oil (MBbl) (2) (3)-			
December 31, 1999	1,304	24,600	25,904
December 31, 2000	2,567	32,929	35,496
December 31, 2001	2,719	34,131	36,850
Bcf(1) equivalents(4)-			
December 31, 1999	201	463	664
December 31, 2000	283	588	871
December 31, 2001	394	599	993

(1) Billion cubic feet or billion cubic feet equivalent, as applicable.

(2) Thousand barrels.

(3) Includes crude oil, condensate and natural gas liquids.

(4) Natural gas liquids and crude oil volumes have been converted to equivalent gas volumes using a conversion factor of six cubic feet of gas to one barrel of natural gas liquids and crude oil.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information has been developed utilizing procedures prescribed by SFAS No. 69 and based on natural gas and crude oil reserve and production volumes estimated by the independent petroleum consultants. This information may be useful for certain comparison purposes but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's oil and gas assets.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of natural gas and crude oil reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used. Income tax expense, for both the United States and Canada, has been computed using expected future tax rates and giving effect to tax deductions and credits available, under current laws, and which relate to oil and gas producing activities.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company's natural gas and crude oil reserves for the years ended December 31, 2001, 2000, and 1999 (in millions):

	United States	Canada	Total
December 31, 2001 —			
Future cash inflows	$ 1,609	$ 1,621	$ 3,230
Future production and development costs	(602)	(569)	(1,171)
Future net cash flows before income taxes	1,007	1,052	2,059
Future income taxes	(217)	(245)	(462)
Future net cash flows	790	807	1,597
Discount to present value at 10% annual rate	(349)	(269)	(618)
Standardized measure of discounted future net cash flows relating to proved gas, natural gas liquids and crude oil reserves	$ 441	$ 538	$ 979
December 31, 2000 —			
Future cash inflows	$ 3,815	$ 5,559	$ 9,374
Future production and development costs	(475)	(759)	(1,234)
Future net cash flows before income taxes	3,340	4,800	8,140
Future income taxes	(970)	(1,808)	(2,778)
Future net cash flows	2,370	2,992	5,362
Discount to present value at 10% annual rate	(1,172)	(1,112)	(2,284)
Standardized measure of discounted future net cash flows relating to proved gas, natural gas liquids and crude oil reserves	$ 1,198	$ 1,880	$ 3,078
December 31, 1999 —			
Future cash inflows	$ 485	$ 1,599	$ 2,084
Future production and development costs	(137)	(436)	(573)
Future net cash flows before income taxes	348	1,163	1,511
Future income taxes	(56)	(350)	(406)
Future net cash flows	292	813	1,105
Discount to present value at 10% annual rate	(139)	(263)	(402)
Standardized measure of discounted future net cash flows relating to proved gas, natural gas liquids and crude oil reserves	$ 153	$ 550	$ 703

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, 2001, 2000, and 1999 (in millions):

	United States	Canada	Total
Balance, December 31, 1998.	7	319	326
Sales and transfers of gas, natural gas liquids and crude oil produced, net of production costs	(7)	(98)	(105)
Net changes in prices and production costs	1	243	244
Extensions, discoveries, additions and improved recovery, net of related costs	—	162	162
Development costs incurred	—	27	27
Revisions of previous quantity estimates and development costs	(18)	(9)	(27)
Accretion of discount	1	26	27
Net change in income taxes	(29)	(127)	(156)
Purchases of reserves in place	185	34	219
Sales of reserves in place	—	(19)	(19)
Changes in timing and other	13	(8)	5
Balance, December 31, 1999.	153	550	703
Sales and transfers of gas, natural gas liquids and crude oil produced, net of production costs	(91)	(245)	(336)
Net changes in prices and production costs	984	1,717	2,701
Extensions, discoveries, additions and improved recovery, net of related costs	129	475	604
Development costs incurred	8	25	33
Revisions of previous quantity estimates and development costs	148	(215)	(67)
Accretion of discount	15	39	54
Net change in income taxes	(462)	(938)	(1,400)
Purchases of reserves in place	492	603	1,095
Sales of reserves in place	(2)	(17)	(19)
Changes in timing and other	(176)	(114)	(290)
Balance, December 31, 2000.	$ 1,198	$ 1,880	$ 3,078
Sales and transfers of gas, natural gas liquids and crude oil produced, net of production costs	(181)	(273)	(454)
Net changes in prices and production costs	(1,312)	(1,733)	(3,045)
Extensions, discoveries, additions and improved recovery, net of related costs	165	70	235
Development costs incurred	26	46	72
Revisions of previous quantity estimates and development costs	(110)	(298)	(408)
Accretion of discount	120	40	160
Net change in income taxes	370	869	1,239
Purchases of reserves in place	187	6	193
Sales of reserves in place	(48)	(36)	(84)
Changes in timing and other	26	(33)	(7)
Balance, December 31, 2001	$ 441	$ 538	$ 979

EXHIBIT INDEX

Exhibit Number	Description
3.1.1	Amended and Restated Certificate of Incorporation of Calpine Corporation.(a)
3.1.2	Certificate of Correction of Calpine Corporation.(b)
3.1.3	Certificate of Amendment of Amended and Restated Certificate of Incorporation of Calpine Corporation.(c)
3.1.4	Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(b)
3.1.5	Amendment to Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(b)
3.1.6	Amendment to Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(c)
3.1.7	Certificate of Designation of Special Voting Preferred Stock of Calpine Corporation.(d)
3.1.8	Amended and Restated By-laws of Calpine Corporation.(*)
4.1.1	Indenture dated as of May 16, 1996, between the Company and Fleet National Bank, as Trustee, including form of Notes.(f)
4.1.2	First Supplemental Indenture dated as of August 1, 2000, between the Company and State Street Bank and Trust Company (successor trustee to Fleet National Bank), as Trustee.(b)
4.2.1	Indenture dated as of July 8, 1997, between the Company and The Bank of New York, as Trustee, including form of Notes.(g)
4.2.2	Supplemental Indenture dated as of September 10, 1997, between the Company and The Bank of New York, as Trustee.(h)
4.2.3	Second Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.3.1	Indenture dated as of March 31, 1998, between the Company and The Bank of New York, as Trustee, including form of Notes.(i)
4.3.2	Supplemental Indenture dated as of July 24, 1998, between the Company and The Bank of New York, as Trustee.(i)
4.3.3	Second Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.4.1	Indenture dated as of March 29, 1999, between the Company and The Bank of New York, as Trustee, including form of Notes.(j)
4.4.2	First Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.5.1	Indenture dated as of March 29, 1999, between the Company and The Bank of New York, as Trustee, including form of Notes.(j)
4.5.2	First Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.6.1	Indenture dated as of August 10, 2000, between the Company and Wilmington Trust Company, as Trustee.(k)
4.6.2	First Supplemental Indenture dated as of September 28, 2000, between the Company and Wilmington Trust Company, as Trustee.(b)
4.7	Indenture, dated as of April 30, 2001, between the Company and Wilmington Trust Company, as Trustee.(m)
4.8	Amended and Restated Indenture dated as of October 16, 2001, between Calpine Canada Energy Finance ULC and Wilmington Trust Company, as Trustee.(1)
4.9	Guarantee Agreement dated as of April 25, 2001, between the Company and Wilmington Trust Company, as Trustee.(o)
4.10	First Amendment, dated as of October 16, 2001, to Guarantee Agreement dated as of April 25, 2001, between the Company and Wilmington Trust Company, as Trustee.(l)

Exhibit Number	Description
4.11	Indenture dated as of October 18, 2001, between Calpine Canada Energy Finance II ULC and Wilmington Trust Company, as Trustee.(l)
4.12	First Supplemental Indenture, dated as of October 18, 2001, between Calpine Canada Energy Finance II ULC and Wilmington Trust Company, as Trustee.(1)
4.13	Guarantee Agreement dated as of October 18, 2001, between the Company and Wilmington Trust Company, as Trustee.(l)
4.14	First Amendment, dated as of October 18, 2001, to Guarantee Agreement dated as of October 18, 2001, between the Company and Wilmington Trust Company, as Trustee.(l)
4.15	Amended and Restated Rights Agreement, dated as of September 19, 2001, between Calpine Corporation and Equiserve Trust Company, N.A., as Rights Agent.(n)
4.16	Form of Exchangeable Share Provisions and Other Provisions to Be Included in the Articles of Calpine Canada Holdings Ltd. (included as Exhibit B to Exhibit 10.1.2).(d)
4.17	Form of Support Agreement between the Company and Calpine Canada Holdings Ltd. (included as Exhibit C to Exhibit 10.1.1).(d)
4.18	HIGH TIDES I.
4.18.1	Certificate of Trust of Calpine Capital Trust, a Delaware statutory trust, dated September 29, 1999.(p)
4.18.2	Corrected Certificate of Certificate of Trust of Calpine Capital Trust, a Delaware statutory trust, filed October 4, 1999.(p)
4.18.3	Declaration of Trust of Calpine Capital Trust, dated as of October 4, 1999, among Calpine Corporation, as Depositor, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein.(p)
4.18.4	Indenture, dated as of November 2, 1999, between Calpine Corporation and The Bank of New York, as Trustee, including form of Debenture.(p)
4.18.5	Remarketing Agreement, dated November 2, 1999, among Calpine Corporation, Calpine Capital Trust, The Bank of New York, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(p)
4.18.6	Amended and Restated Declaration of Trust of Calpine Capital Trust, dated as of November 2, 1999, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, and The Bank of New York, as Property Trustee, and the Administrative Trustees named therein, including form of Preferred Security and form of Common Security.(p)
4.18.7	Preferred Securities Guarantee Agreement, dated as of November 2, 1999, between Calpine Corporation and The Bank of New York, as Guarantee Trustee.(p)
4.19	HIGH TIDES II.
4.19.1	Certificate of Trust of Calpine Capital Trust II, a Delaware statutory trust, filed January 25, 2000.(q)
4.19.2	Declaration of Trust of Calpine Capital Trust II, dated as of January 24, 2000, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein.(q)
4.19.3	Indenture, dated as of January 31, 2000, between Calpine Corporation and The Bank of New York, as Trustee, including form of Debenture.(q)
4.19.4	Remarketing Agreement, dated as of January 31, 2000, among Calpine Corporation, Calpine Capital Trust II, The Bank of New York, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(q)
4.19.5	Registration Rights Agreement, dated January 31, 2000, among Calpine Corporation, Calpine Capital Trust II, Credit Suisse First Boston Corporation and ING Barings LLC.(q)

Exhibit Number	Description
4.19.6	Amended and Restated Declaration of Trust of Calpine Capital Trust II, dated as of January 31, 2000, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein, including form of Preferred Security and form of Common Security.(q)
4.19.7	Preferred Securities Guarantee Agreement, dated as of January 31, 2000, between Calpine Corporation and The Bank of New York, as Guarantee Trustee.(q)
4.20	HIGH TIDES III.
4.20.1	Amended and Restated Certificate of Trust of Calpine Capital Trust III, a Delaware statutory trust, filed July 19, 2000.(r)
4.20.2	Declaration of Trust of Calpine Capital Trust III dated June 28, 2000, among the Company, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee and the Administrative Trustees named therein.(r)
4.20.3	Amendment No. 1 to the Declaration of Trust of Calpine Capital Trust III dated July 19, 2000, among the Company, as Depositor and Debenture Issuer, Wilmington Trust Company, as Delaware Trustee, Wilmington Trust Company, as Property Trustee, and the Administrative Trustees named therein.(r)
4.20.4	Indenture dated as of August 9, 2000, between the Company and Wilmington Trust Company, as Trustee.(r)
4.20.5	Remarketing Agreement dated as of August 9, 2000, among the Company, Calpine Capital Trust III, Wilmington Trust Company, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(r)
4.20.6	Registration Rights Agreement dated as August 9, 2000, between the Company, Calpine Capital Trust III, Credit Suisse First Boston Corporation, ING Barings LLC and CIBC World Markets Corp.(r)
4.20.7	Amended and Restated Declaration of Trust of Calpine Capital Trust III dated as of August 9, 2000, the Company, as Depositor and Debenture Issuer, Wilmington Trust Company, as Delaware Trustee, Wilmington Trust Company, as Property Trustee, and the Administrative Trustees named therein, including the form of Preferred Security and form of Common Security.(r)
4.20.8	Preferred Securities Guarantee Agreement dated as of August 9, 2000, between the Company, as Guarantor, and Wilmington Trust Company, as Guarantee Trustee.(r)
4.21	PASS THROUGH CERTIFICATES (TIVERTON AND RUMFORD).
4.21.1	Pass Through Trust Agreement dated as of December 19, 2000, among Tiverton Power Associates Limited Partnership, Rumford Power Associates Limited Partnership and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of Certificate.(b)
4.21.2	Participation Agreement dated as of December 19, 2000, among the Company, Tiverton Power Associates Limited Partnership, Rumford Power Associates Limited Partnership, PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee.(b)
4.21.3	Appendix A — Definitions and Rules of Interpretation.(b)
4.21.4	Indenture of Trust, Mortgage and Security Agreement, dated as of December 19, 2000, between PMCC Calpine New England Investment LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, including the forms of Lessor Notes.(b)
4.21.5	Calpine Guaranty and Payment Agreement (Tiverton) dated as of December 19, 2000, by Calpine, as Guarantor, to PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(b)

Exhibit Number	Description
4.21.6	Calpine Guaranty and Payment Agreement (Rumford) dated as of December 19, 2000, by Calpine, as Guarantor, to PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(b)
4.22	PASS THROUGH CERTIFICATES (SOUTH POINT, BROAD RIVER AND ROCKGEN).
4.22.1	Pass Through Trust Agreement A dated as of October 18, 2001, among South Point Energy Center, LLC, Broad River Energy LLC, RockGen Energy LLC and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of 8.400% Pass Through Certificate, Series A.(*)
4.22.2	Pass Through Trust Agreement B dated as of October 18, 2001, among South Point Energy Center, LLC, Broad River Energy LLC, RockGen Energy LLC and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of 9.825% Pass Through Certificate, Series B.(*)
4.22.3	Participation Agreement (SP-1) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.4	Participation Agreement (SP-2) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.5	Participation Agreement (SP-3) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.6	Participation Agreement (SP-4) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.7	Participation Agreement (BR-1) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.8	Participation Agreement (BR-2) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)

Exhibit Number	Description
4.22.9	Participation Agreement (BR-3) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.10	Participation Agreement (BR-4) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.11	Participation Agreement (RG-1) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.12	Participation Agreement (RG-2) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.13	Participation Agreement (RG-3) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.14	Participation Agreement (RG-4) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(*)
4.22.15	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(*)
4.22.16	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(*)
4.22.17	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(*)
4.22.18	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(*)

Exhibit Number	Description
4.22.19	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(*)
4.22.20	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(*)
4.22.21	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(*)
4.22.22	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(*)
4.22.23	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(*)
4.22.24	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(*)
4.22.25	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(*)
4.22.26	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(*)
4.22.27	Calpine Guaranty and Payment Agreement (South Point SP-1) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.28	Calpine Guaranty and Payment Agreement (South Point SP-2) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.29	Calpine Guaranty and Payment Agreement (South Point SP-3) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.30	Calpine Guaranty and Payment Agreement (South Point SP-4) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.31	Calpine Guaranty and Payment Agreement (Broad River BR-1) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)

Exhibit Number	Description
4.22.32	Calpine Guaranty and Payment Agreement (Broad River BR-2) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.33	Calpine Guaranty and Payment Agreement (Broad River BR-3) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.34	Calpine Guaranty and Payment Agreement (Broad River BR-4) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.35	Calpine Guaranty and Payment Agreement (RockGen RG-1) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.36	Calpine Guaranty and Payment Agreement (RockGen RG-2) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.37	Calpine Guaranty and Payment Agreement (RockGen RG-3) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
4.22.38	Calpine Guaranty and Payment Agreement (RockGen RG-4) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(*)
9.1	Form of Voting and Exchange Trust Agreement between the Company, Calpine Canada Holdings Ltd. and CIBC Mellon Trust Company, as Trustee (included as Exhibit D to Exhibit 10.1.1).(d)
10.1	Purchase Agreements.
10.1.1	Combination Agreement, dated as of February 7, 2001, by and between the Company and Encal Energy Ltd.(d)
10.1.2	Amending Agreement to the Combination Agreement, dated as of March 16, 2001, between the Company and Encal Energy Ltd.(t)
10.1.3	Form of Plan of Arrangement Under Section 186 of the Business Corporations Act (Alberta) Involving and Affecting Encal Energy Ltd. and the Holders of its Common Shares and Options (included as Exhibit A to Exhibit 10.1.1).(d)
10.2	Financing Agreements.
10.2.1	Amended and Restated Calpine Construction Finance Company Financing Agreement ("CCFC I"), dated as of February 15, 2001.(d)(u)
10.2.2	Calpine Construction Finance Company Financing Agreement ("CCFC II"), dated as of October 16, 2000.(b)(v)
10.2.3	Second Amended and Restated Credit Agreement, dated as of May 23, 2000 ("Second Amended and Restated Credit Agreement"), among the Company, Bayerische Landesbank, as Co-Arranger and Syndication Agent, The Bank of Nova Scotia, as Lead Arranger and Administrative Agent, and the Lenders named therein.(w)
10.2.4	First Amendment and Waiver to Second Amended and Restated Credit Agreement, dated as of April 19, 2001, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(*)

Exhibit Number	Description
10.2.5	Second Amendment to Second Amended and Restated Credit Agreement, dated as of March 8, 2002, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(*)
10.2.6	Credit Agreement, dated as of March 8, 2002, among the Company, the Lenders named therein, The Bank of Nova Scotia and Bayerische Landesbank Girozentrale, as lead arrangers and bookrunners, Salomon Smith Barney Inc. and Deutsche Banc Alex. Brown Inc., as lead arrangers and bookrunners, Bank of America, National Association, and Credit Suisse First Boston, Cayman Islands Branch, as lead arrangers and syndication agents, TD Securities (USA) Inc., as lead arranger, The Bank of Nova Scotia, as joint administrative agent and funding agent, and Citicorp USA, Inc., as joint administrative agent.(*)
10.2.7	Assignment and Security Agreement, dated as of March 8, 2002, by the Company in favor of The Bank of Nova Scotia, as administrative agent for each of the Lender Parties named therein.(*)
10.2.8	Pledge Agreement, dated as of March 8, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent for the Lender Parties named therein.(*)
10.2.9	Pledge Agreement, dated as of March 8, 2002, by Quintana Minerals (USA), Inc., JOQ Canada, Inc. and Quintana Canada Holdings, LLC in favor of The Bank of Nova Scotia, as Agent for the Lender Parties named therein.(*)
10.2.10	Guarantee, dated as of March 8, 2002, by Quintana Minerals (USA), Inc., JOQ Canada, Inc. and Quintana Canada Holdings, LLC, in favor of each of the Lender Parties named therein.(*)
10.3	Other Agreements.
10.3.1	Calpine Corporation Stock Option Program and forms of agreements there under.(x)(z)
10.3.2	Calpine Corporation 1996 Stock Incentive Plan and forms of agreements there under.(y)(z)
10.3.3	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Peter Cartwright.(q)(z)
10.3.4	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Ms. Ann B. Curtis.(*)(z)
10.3.5	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Ron A. Walter.(*)(z)
10.3.6	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Robert D. Kelly.(*)(z)
10.3.7	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Thomas R. Mason.(*)(z)
10.3.8	Calpine Corporation Annual Management Incentive Plan.(s)(z)
10.3.9	$500,000 Promissory Note Secured by Deed of Trust made by Thomas R. Mason and Debra J. Mason in favor of Calpine Corporation.(s)(z)
10.4.1	Form of Indemnification Agreement for directors and officers.(y)(z)
10.4.2	Form of Indemnification Agreement for directors and officers.(*)(z)
12.1	Statement on Computation of Ratio of Earnings to Fixed Charges.(*)
16.1	Letter re Change in Certifying Public Accountant.(*)
21.1	Subsidiaries of the Company.(*)
23.1	Consent of Arthur Andersen LLP, Independent Public Accountants.(*)
23.2	Consent of Ernst & Young LLP, Independent Chartered Accountants.(*)
23.3	Consent of Netherland, Sewell & Associates, Inc., independent engineer.(*)
23.4	Consent of Gilbert Laustsen Jung Associates, Ltd., independent engineer.(*)
24.1	Power of Attorney of Officers and Directors of Calpine Corporation (set forth on the signature pages of this report).(*)
99.1	Letter pursuant to Temporary Note 3T to Article 3 of Regulation S-X.(*)

(*) Filed herewith.

(a) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration No. 333-40652) filed with the SEC on June 30, 2000.

(b) Incorporated by reference to Calpine Corporation's Annual Report on Form 10-K for the year ended December 31, 2000, filed with the SEC on March 15, 2001.

(c) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration No. 333-66078) filed with the SEC on July 27, 2001.

(d) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated March 31, 2001, filed with the SEC on May 15, 2001.

(e) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration No. 333-67446) filed with the SEC on September 20, 2001.

(f) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-4 (Registration Statement No. 333-06259) filed with the SEC on June 19, 1996.

(g) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated June 30, 1997, filed with the SEC on August 14, 1997.

(h) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-4 (Registration Statement No. 333-41261) filed with the SEC on November 28, 1997.

(i) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-4 (Registration Statement No. 333-61047) filed with the SEC on August 10, 1998.

(j) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration Statement No. 333-72583) filed with the SEC on March 8, 1999.

(k) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration No. 333-76880) filed with the SEC on January 17, 2002.

(l) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated October 16, 2001, filed with the SEC on November 13, 2001.

(m) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated October 16, 2001, filed with the SEC on November 13, 2001.

(n) Incorporated by reference to Calpine Corporation's Registration Statement on Form 8-A/A (Registration No. 001-12079) filed with the SEC on September 28, 2001.

(o) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration No. 333-57338) filed with the SEC on April 19, 2001.

(p) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration Statement No. 333-87427) filed with the SEC on October 26, 1999.

(q) Incorporated by reference to Calpine Corporation's Annual Report on Form 10-K for the year ended December 31, 1999, filed with the SEC on February 29, 2000.

(r) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration Statement No. 333-47068) filed with the SEC on September 29, 2000.

(s) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated March 30, 2000, filed with the SEC on April 3, 2000.

(t) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration Statement No. 333-56712) filed with the SEC on April 17, 2001.

(u) Approximately 24 pages of this exhibit have been omitted pursuant to a request for confidential treatment. The omitted language has been filed separately with the SEC.

(v) Approximately 71 pages of this exhibit have been omitted pursuant to a request for confidential treatment. The omitted language has been filed separately with the SEC.

(w) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated July 25, 2000, filed with the SEC on August 9, 2000.

(x) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-1 (Registration Statement No. 33-73160) filed with the SEC on December 20, 1993.

(y) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-1/A (Registration Statement No. 333-07497) filed with the SEC on August 22, 1996.

(z) Management contract or compensatory plan or arrangement.

CORPORATE INFORMATION

BOARD OF DIRECTORS

Peter Cartwright
Chairman, Chief Executive Officer, and President

Ann B. Curtis
Vice Chairman, Executive Vice President, and Secretary

Jeffrey E. Garten
Dean, Yale School of Management

Susan C. Schwab
Dean, School of Public Affairs University of Maryland

George J. Stathakis
Senior Advisor to Calpine; Chief Executive Officer of G. J. Stathakis & Associates, and Former General Electric Company Executive

John O. Wilson
Senior Research Fellow, Berkeley Roundtable on the International Economy, and Executive Vice President and Chief Economist, SDR Capital Management, Inc.

Kenneth T. Derr
Former Chairman and Chief Executive Officer of Chevron, and former Chairman of the American Petroleum Institute

Gerald Greenwald
Former Chairman and Chief Executive Officer of UAL Corporation

OFFICERS

Peter Cartwright

Ann B. Curtis

Lisa M. Bodensteiner
Senior Vice President and General Counsel

Charles B. Clark, Jr.
Senior Vice President, Chief Accounting Officer and Corporate Controller

Robert D. Kelly
Executive Vice President, Chief Financial Officer and President, Calpine Finance Company

E. James Macias
Executive Vice President and Chief Operating Officer

Thomas R. Mason
Executive Vice President

CORPORATE DATA

Stock Transfer Agent and Registrar
EquiServe Trust Company, N.A.
P.O. Box 2500
Jersey City, New Jersey 07303
Stockholder inquiries: 201.324.1644
Hearing impaired: 201.222.4955
Web site: www.equiserve.com

SEC Report
If you would like a copy of Calpine's annual report, with Form 10-K filed with the Securities and Exchange Commission, please contact Investor Relations at 800.359.5115, extension 2355, or by e-mail at investor-relations@calpine.com

Investor Relations Contact
Richard D. Barraza
Senior Vice President,
Investor Relations
Calpine Corporation
50 West San Fernando Street
San Jose, California 95113
408.995.5115, extension 1125
408.294.2877 (fax)
E-mail: rickb@calpine.com

Corporate Auditor
Arthur Andersen LLP — 2001
River Park Tower, Suite 1500
333 West San Carlos Street
San Jose, California 95110

Deloitte and Touche LLP — 2002
225 W. Santa Clara St., Suite 600
San Jose, California 95113

Annual Meeting
The annual meeting of the stockholders of Calpine Corporation will be held on May 23, 2002, at 9:00 a.m. at the Seascape Resort, One Seascape Resort Drive, Aptos, California 95003

Stock Listing
New York Stock Exchange symbol: CPN