A GENERATION AHEAD, *today*

2010 ANNUAL REPORT

CALPINE®

NYSE CPN

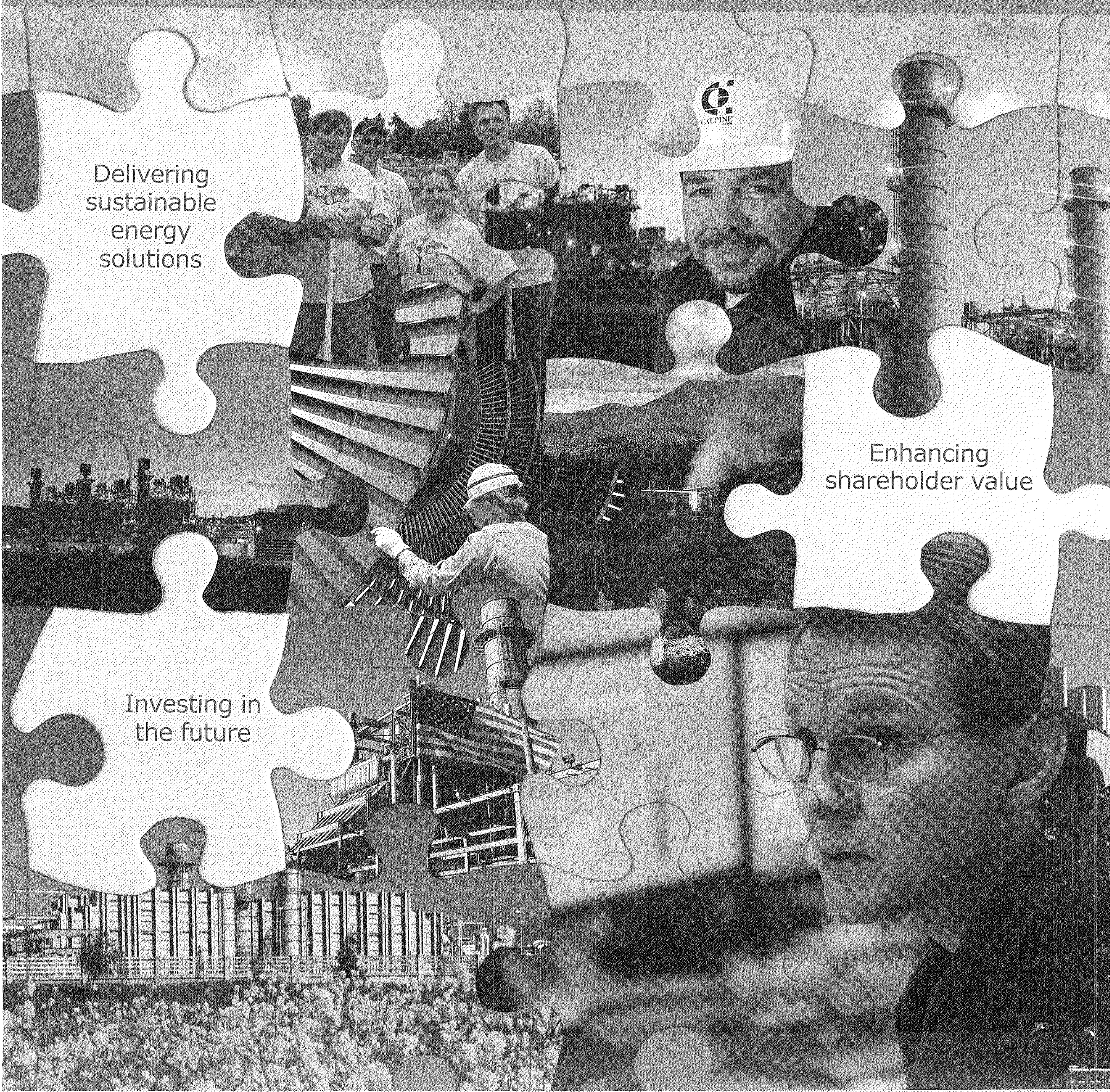
A generation ahead, today.

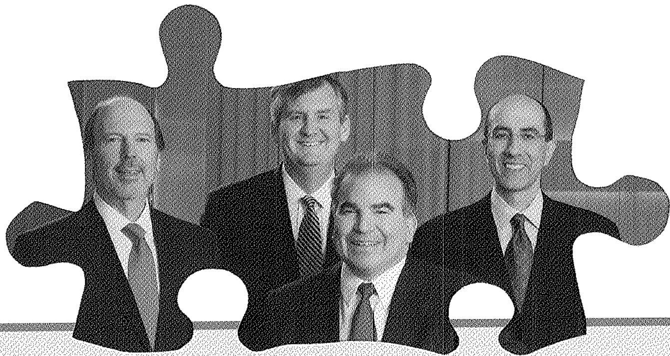
Calpine's power generation portfolio contains critical pieces needed to help solve the puzzle of America's clean energy future.

Our natural gas-fired generation is the preferable environmental and economic choice. It emits less than half the carbon, a fraction of the sulfur dioxide and nitrous oxide, and no mercury compared to coal-fired generation. The impact of the recent vast shale gas finds on natural gas prices into the foreseeable future make it a compelling economic choice, particularly when compared to escalating coal prices. Operationally, our existing fleet, which has substantial excess capacity to serve the market, provides baseload power as older coal-fired generation retires. Finally, the intermediate and peaking flexibility and reliability of our fleet is essential to the integration of intermittent renewable power sources into the grid.

Our geothermal generation at The Geysers is the ideal renewable generation source, providing reliable power around the clock.

As the new economics of modern, efficient natural gas-fired generation take hold and as environmental imperatives force older coal-fired generation to retire, Calpine's modern, flexible and reliable fleet stands ready to lead our nation's march toward a cleaner energy future.





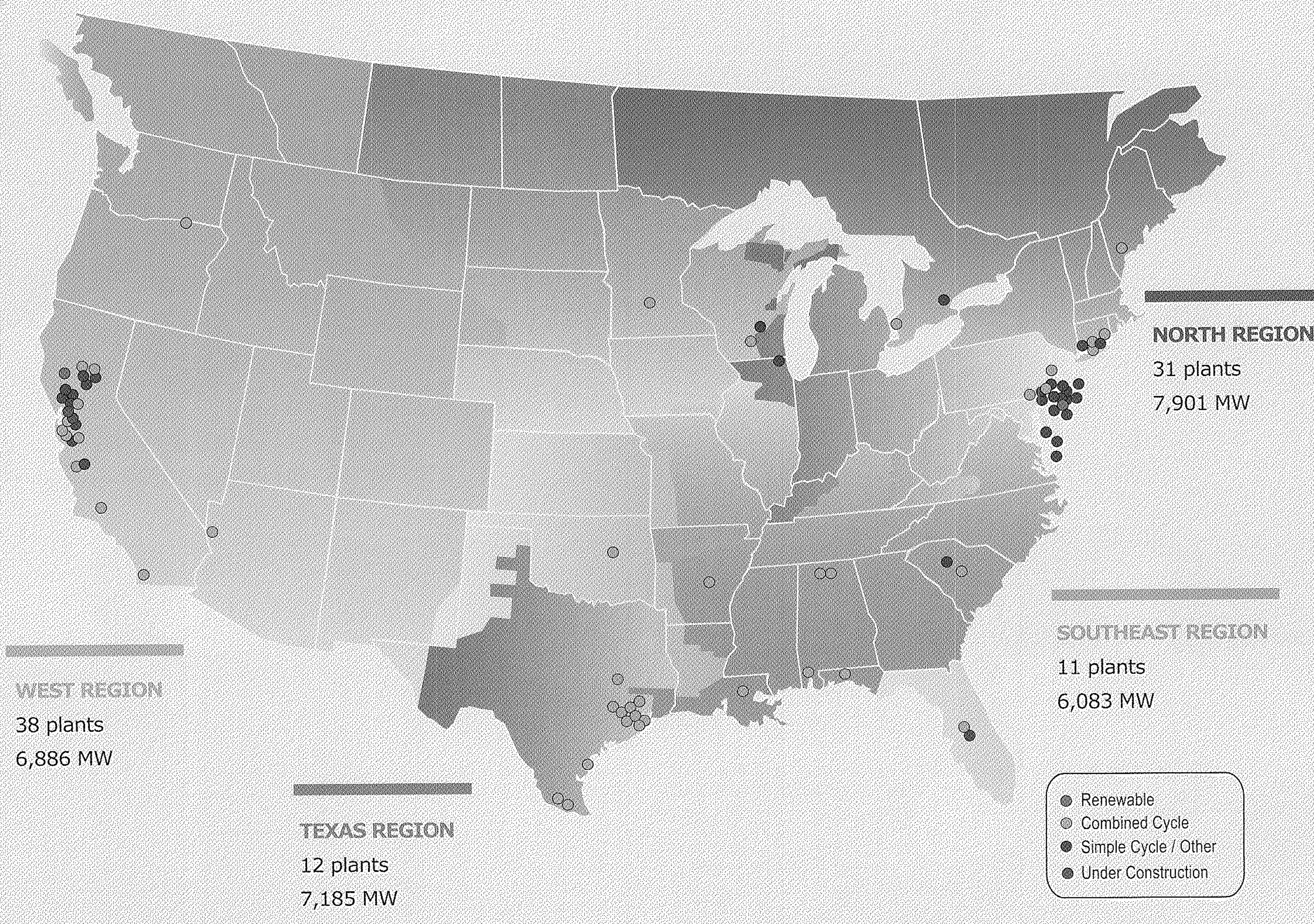
Calpine Leadership

We remain committed to achieving operational excellence, demonstrating financially disciplined growth and enhancing shareholder value. We have the privilege of managing the industry's most talented men and women dedicated to a common goal of becoming the best independent power producer in the country.

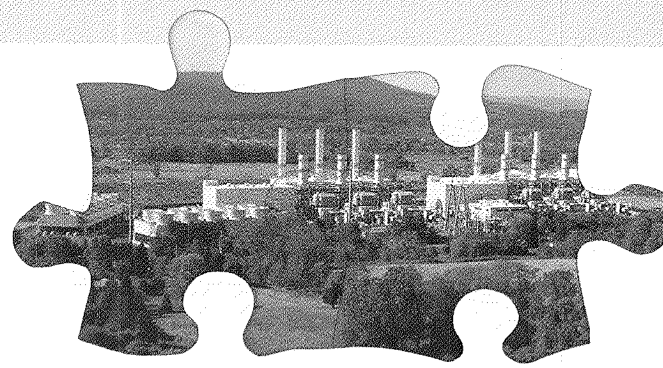
Jack Fusco, Chief Executive Officer
Thad Hill, Chief Operating Officer
Thad Miller, Chief Legal Officer
Zamir Rauf, Chief Financial Officer

National Portfolio of 28,055 MW

2010 Production: Over 94,000,000 MWh



DEAR FELLOW SHAREHOLDERS:



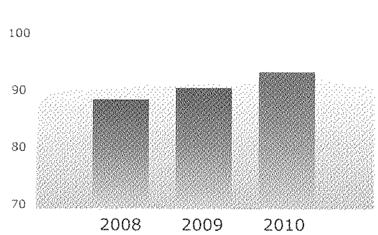
Bethlehem Energy Center

Calpine advanced on multiple fronts in 2010:

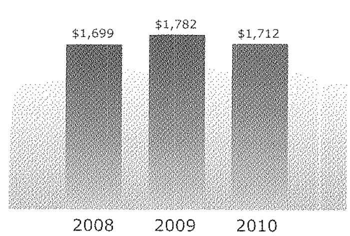
- We acquired 4,490 MW of generating capacity in the PJM market for approximately $380/kW;
- We opportunistically sold 1,190 MW of generating capacity in transactions involving two plants and an undivided interest in another for approximately $800/kW;
- We made attractive investments in our ongoing turbine upgrade program, which, when completed, will result in the addition of 275 MW of new generating capacity at an equivalent installed cost of approximately $200/kW;
- We completed the refinancing of our legacy credit facility, achieving a more balanced maturity profile with more flexible, investment grade-like covenants, giving us additional tools to enhance shareholder value; and
- We delivered more reliable, cost-effective and environmentally responsible energy solutions for our customers.

Our share price increased 21% during the year, versus flat to negative performance by the S&P 500 Utility Index and most of our independent power competitors. We also received a credit rating upgrade from Moody's Investment Services.

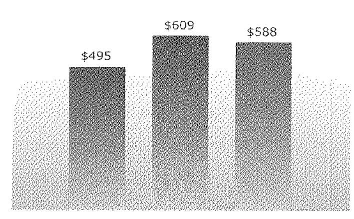
GENERATION VOLUME
(TWh)

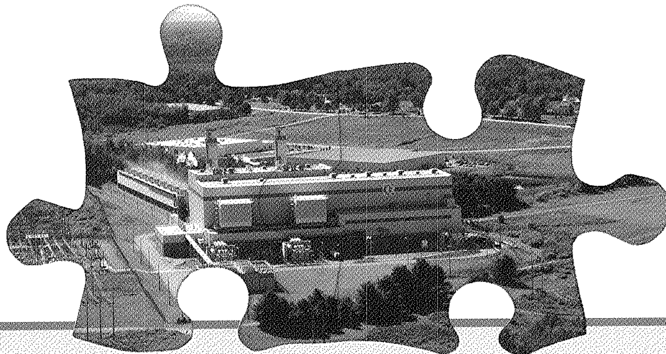


ADJUSTED EBITDA
($ millions)



ADJUSTED RECURRING FREE CASH FLOW
($ millions)





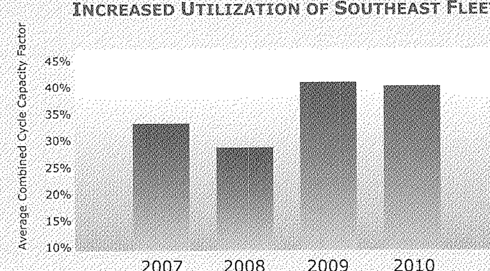
In 2010, our Westbrook Energy Center was recognized as a Star Worksite under the Voluntary Protection Programs (VPP) of the U.S. Department of Labor's Occupational Safety and Health Administration (OSHA). The VPP Star Certification is OSHA's highest level of recognition for outstanding worksite health and safety efforts.

Carville Energy Center

Well positioned for sustained mid-range gas price environment

Carville Energy Center, a 501 MW cogeneration power plant located in St. Gabriel, Louisiana, is one of the plants in our Southeast region that has experienced higher capacity factors in recent years, we believe largely as a result of fundamental changes in the prices of coal and natural gas. We believe Calpine is well positioned to benefit from these dynamics over the long term.

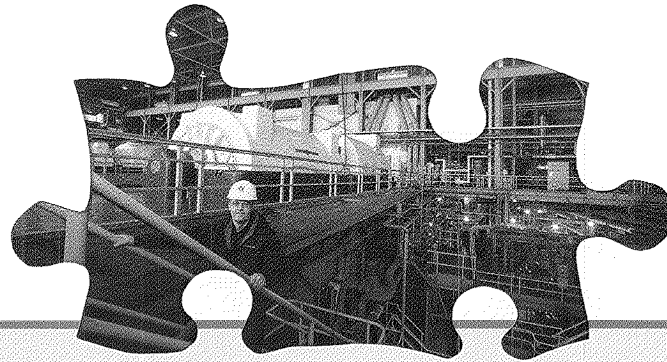
INCREASED UTILIZATION OF SOUTHEAST FLEET



Delivering Sustainable Energy Solutions to Our Customers

Reliability is important to customer satisfaction. In 2010, we achieved an impressive fleet-wide availability of 91% and starting reliability of 98%. We produced 94 million MWh of electricity, up 3% from 2009 and 6% over 2008.

We also strive to provide our customers with environmentally responsible electricity. Our geothermal facilities at The Geysers in Northern California generate over 20% of California's total renewable electricity. Our fleet of natural gas-fired plants (i) has the lowest greenhouse gas footprint (CO_2 per MWh) of any major independent power producer in the U.S., (ii) emits no mercury, (iii) utilizes almost no once-through cooling, (iv) produces no ash byproduct, and (v) emits a small fraction of the SO_2 and NOx emitted by our competitors.



Demonstrating environmental leadership

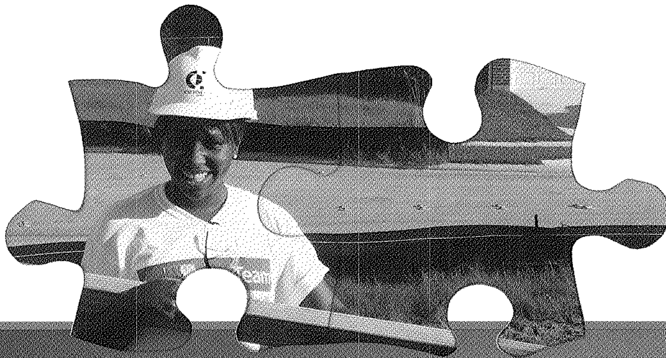
After acquiring our Mid-Atlantic fleet in July 2010, we voluntarily elected to stop burning coal at the two sites that had historically operated as coal-fired generation facilities. Consistent with the environmental stewardship for which we are known, our decision to convert approximately 340 MW of coal-fired generation to run primarily on natural gas will benefit our communities for years to come.

Edge Moor Energy Center (before)

Edge Moor Energy Center (after) *Rendering*

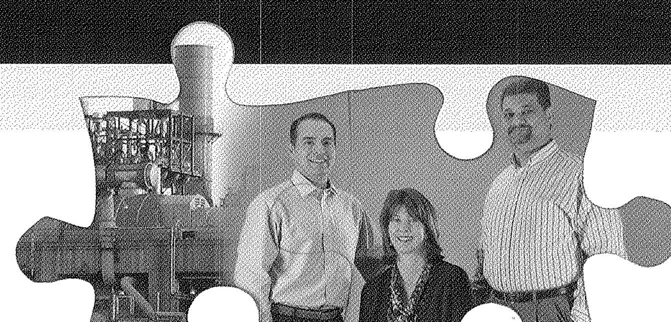
In addition, last year we:

- Converted the two coal-fired units we acquired as part of our PJM transaction to operate on natural gas and dismantled their coal handling capabilities and
- Broke ground on the construction of our 619 MW Russell City Energy Center in California, which will be the first plant in America to operate in effect with greenhouse gas emissions limitations in its air permit, a set of operating conditions we voluntarily agreed to accept.



ENHANCING shareholder value

Freestone Energy Center



Our 2010 sale of a 25% undivided interest in the Freestone Energy Center exemplifies the importance of our focus on strategic origination. Thanks to the efforts of Rick Pena, Sally MacDonald and Micheal Elias, we were able to partner with Rayburn Country Electric Cooperative through a transaction that satisfied Rayburn's desire to own an interest in a power plant while providing us with the opportunity to monetize value for our shareholders.

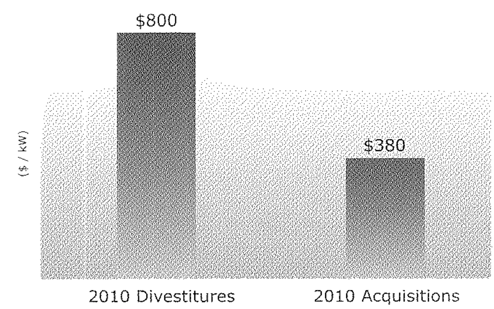
The acquisition of our Mid-Atlantic fleet added meaningful value to our portfolio and gave us scale in one of the country's most robust wholesale power markets. The efforts of Will Stokes, Todd Thornton, Shonnie Daniels, Danita Park and Stacey Peterson were instrumental in completing this successful transaction.

Delivering Value to Our Owners

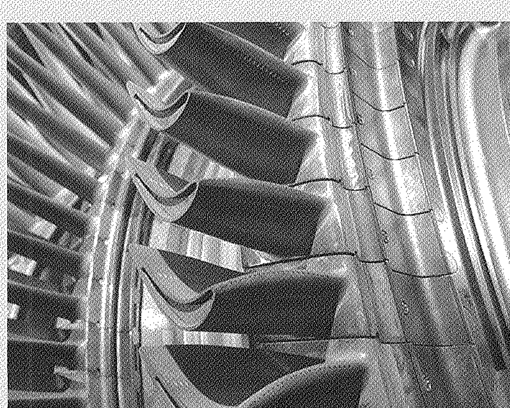
In 2010, we enhanced the value of our business in a number of ways. On July 1, we closed on the $1.6 billion acquisition of our PJM portfolio — just 70 days after announcing the transaction — adding nearly 4,500 MW of generating capacity in an attractive market at an attractive price of about $380/kW. We also sold Blue Spruce and Rocky Mountain, our two plants in Colorado, and an undivided interest in our Freestone plant in Texas at attractive prices of about $800/kW.

In addition, we completed the refinancing of our legacy credit facility. Our new corporate debt structure features fixed annual interest rates ranging from 7.25 – 8.00%, maturities stretching from 2017 to 2023 and no more than $2 billion maturing in any one year. This new structure has covenants similar to those found in investment grade financings and affords us flexibility to allocate capital in ways that provide the best returns to shareholders.

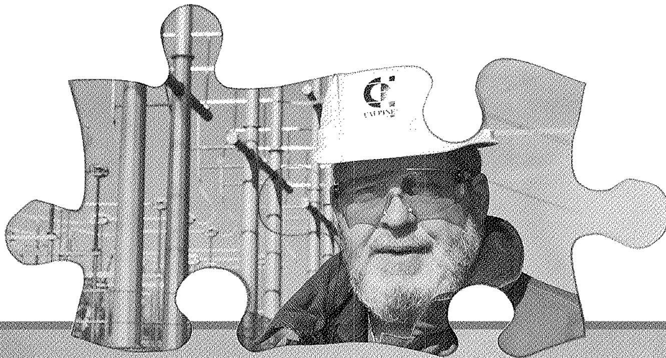
In 2010, we successfully monetized assets through the sale of our power plants in Colorado, a non-core market, and the sale of an undivided interest in our Freestone Energy Center, located in the North Zone of ERCOT. We redeployed this capital through the acquisition of our Mid-Atlantic fleet, which added nearly 4,500 MW of generation capacity in the strategically targeted PJM region.



Finally, we continued to reduce plant operating expenses and administrative costs. By the end of 2010, we had surpassed the $100 million savings target that we set at the beginning of 2009.



We continue to make progress with our turbine upgrade program, which allows us to improve unit efficiencies and add incremental generation capacity at a significant discount to the cost of new build generation. We perform these upgrades in concert with our ongoing plant maintenance cycle to minimize the costs of the upgrades and prioritize availability for our customers. Through January 2011, we had upgraded six of our Siemens turbines and have committed to upgrade 15 more of our Siemens and GE turbines over the balance of the program. When complete, the turbine upgrades are expected to add approximately 275 MW of very efficient generation capacity to our portfolio.



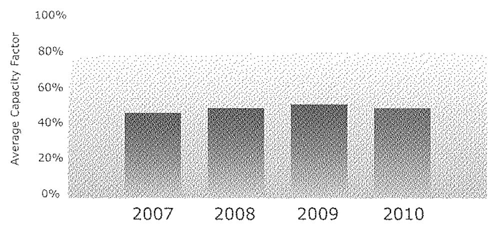
Plant Manager Mike Del Casale oversaw the 29-month construction of York Energy Center and now looks forward to the opportunity to manage its operations.

INVESTING in the future

York Energy Center

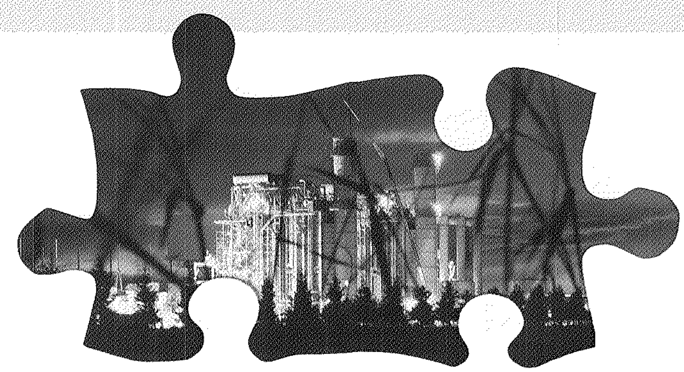
The York Energy Center is a 565 MW combined-cycle power plant located in Peach Bottom Township, Pennsylvania. We acquired this plant in 2010 as part of our strategic entry into the PJM market while the plant was still under construction. In March 2011, York achieved commercial operation ahead of schedule and under its project budget. Starting in June 2011, the output from the plant will be delivered to the customer of a six-year power purchase agreement.

Maintaining Utilization, with Room for More



We have maintained steady fleet utilization factors over the past several years. That being said, our plants are capable of producing much more. As a result, unlike many of our peers whose plants tend to operate as baseload generation, we stand in a position to benefit from higher generation volume driven by power demand recovery: we have available capacity to respond to growing needs for power — no incremental investment is necessary.

Delivering in the Future

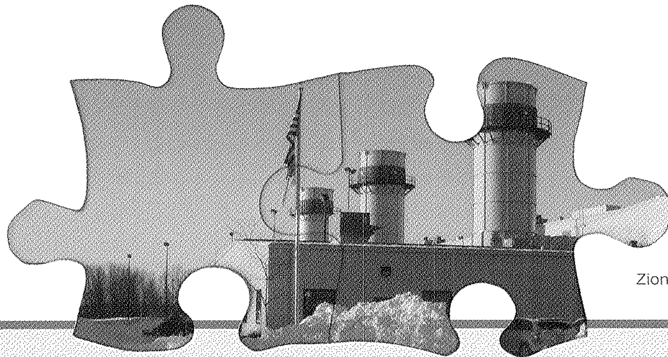

Sutter Energy Center

Economic growth, and with it, electricity demand growth, have returned to Calpine's markets. However, attractive electricity supply and demand balances in those markets may be another year or two away. In the meantime, we will continue to enhance Calpine's competitive position through even better execution in operations, commercial relations and capital allocation.

Looking beyond this period, we expect Calpine to benefit from both better electricity pricing and increased utilization of our power plants. In the East and Southeast, the aging U.S. power generation fleet — with many plants 40–50 years old — may experience significant retirements due to higher coal prices and lower natural gas prices, coupled with the cost of major maintenance and capital improvements. Our fleet of modern, efficient, environmentally responsible natural gas-fired power plants, which were only 46% utilized in 2010, is well positioned to fill the void created by those retirements. Intermittent renewable sources of electricity like wind and solar cannot offer the same reliable solution at attractive prices or in scale, and economically viable new nuclear, coal gasification, carbon capture and sequestration or battery storage solutions are not in sight. So, even in the absence of new environmental regulations, our business is well positioned for growth. Add to that EPA's implementation of existing legislation related to NOx, SO_2 and hazardous air pollutants and the future looks even better.

Despite our optimism about the future, there continue to be challenges. In particular, industry regulators' and power market operators' efforts to circumvent or channel market forces to dampen electricity pricing signals continue to require vigilance. In addition, although the vast new finds of shale gas in the U.S. promise less volatile and mid-range natural gas prices for the foreseeable future, the politics of coal and renewables continue to tempt legislators and regulators away from allowing the market to optimize solutions.

In closing, we are pleased with our performance in 2010 in what was still a tough power market environment. But more importantly, we are excited about Calpine's future. We stand well positioned to benefit from economic recovery, coal-to-gas switching and retirement of older power plants, and we can generate significant additional power in response to these dynamics with virtually no incremental investment. We will continue to look for attractive



Zion Energy Center

opportunities to economically enhance our asset base. And we will continue to take advantage of financially attractive organic growth investment opportunities like our turbine upgrade program, our recently completed York Energy Center, and our Russell City Energy Center and Los Esteros Critical Energy Facility construction projects. We believe that these efforts will continue to keep us a generation ahead, today.

We thank you for your support of Calpine.

Sincerely,

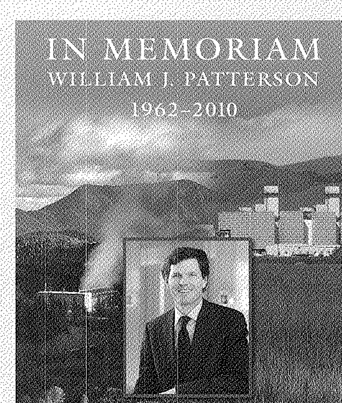
J. Stuart Ryan
Chairman of the Board

Jack Fusco
President and Chief Executive Officer

The people of Calpine Corporation fondly remember and celebrate the life of William J. Patterson, the Chairman of our Board of Directors from January 2008 until he passed away on September 24, 2010.

Bill was a gentleman, an astute investor, a philanthropist and a great supporter of Calpine, its employees and Calpine's commitment to providing America with sustainable electric power generation. Bill's leadership, guidance and advice helped transform Calpine into a successful public company able to make a meaningful contribution to the country's and California's energy future. Bill's imprint on Calpine is indelible.

The Calpine family extends our heartfelt condolences to Bill's wife and his family as they and we celebrate Bill's life.



A GENERATION AHEAD,
today

CALPINE
NYSE CPN

2010 FORM 10-K

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File No. 001-12079

CALPINE®
NYSE CPN

Calpine Corporation

(A Delaware Corporation)
I.R.S. Employer Identification No. 77-0212977
717 Texas Avenue, Suite 1000, Houston, Texas 77002
Telephone: (713) 830-8775
Not Applicable
(Former Address)

Securities registered pursuant to Section 12(b) of the Act:
Calpine Corporation Common Stock, $.001 Par Value
Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [X] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes [ ] No [X]

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 [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] 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. [ ]

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

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes [ ] No [X]

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2010, the last business day of the registrant's most recently completed second fiscal quarter: approximately $3,553 million.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes [X] No [ ]

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: Calpine Corporation: 444,344,629 shares of common stock, par value $.001, were outstanding as of February 15, 2011.

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.

Designated portions of the Proxy Statement relating to the 2011 Annual Meeting of Shareholders are incorporated by reference into Part III (Items 11, 12, 13, 14 and portions of Item 10)

CALPINE CORPORATION AND SUBSIDIARIES

FORM 10-K

ANNUAL REPORT
For the Year Ended December 31, 2010

TABLE OF CONTENTS

DEFINITIONS

As used in this Report, the following abbreviations and terms have the meanings as listed below. Additionally, the terms "Calpine," "we," "us" and "our" refer to Calpine Corporation and its consolidated subsidiaries, unless the context clearly indicates otherwise. For clarification, for the period from December 20, 2005, through February 7, 2008, such terms do not include the Canadian Debtors and other foreign subsidiaries that were deconsolidated as of the Petition Date. The term "Calpine Corporation" refers only to Calpine Corporation and not to any of its subsidiaries. Unless and as otherwise stated, any references in this Report to any agreement means such agreement and all schedules, exhibits and attachments in each case as amended, restated, supplemented or otherwise modified to the date of filing this Report.

ABBREVIATION	DEFINITION
2009 Form 10-K	Calpine Corporation's Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 25, 2010 and as subsequently updated to present our results from Blue Spruce and Rocky Mountain as discontinued operations as filed with the SEC in our Current Report on Form 8-K on November 19, 2010
2017 First Lien Notes	\$1.2 billion aggregate principal amount of 7.25% senior secured notes due 2017, issued October 21, 2009, in exchange for a like principal amount of term loans under the First Lien Credit Facility
2019 First Lien Notes	\$400 million aggregate principal amount of 8.0% senior secured notes due 2019, issued May 25, 2010
2020 First Lien Notes	\$1.1 billion aggregate principal amount of 7.875% senior secured notes due 2020, issued July 23, 2010
2021 First Lien Notes	\$2.0 billion aggregate principal amount of 7.50% senior secured notes due 2021, issued October 22, 2010
2023 First Lien Notes	\$1.2 billion aggregate principal amount of 7.875% senior secured notes due 2023, issued January 14, 2011
AB 32	California Assembly Bill 32
Adjusted EBITDA	EBITDA as adjusted for the effects of (a) impairment losses, (b) reorganization items, (c) major maintenance expense, (d) operating lease expense, (e) any non-cash realized gains on derivatives and any unrealized gains or losses on commodity derivative mark-to-market activity, (f) adjustments to reflect only the Adjusted EBITDA from our unconsolidated investments, (g) stock-based compensation expense, (h) gains or losses on sales, dispositions or retirements of assets, (i) non-cash gains and losses from foreign currency translations, (j) any gains or losses on the repurchase or extinguishment of debt, (k) Conectiv acquisition-related costs, (l) Adjusted EBITDA from our discontinued operations and (m) any other extraordinary, unusual or non-recurring items
Aircraft Services	Aircraft Services Corporation, an affiliate of General Electric Capital Corporation
AOCI	Accumulated Other Comprehensive Income
Auburndale	Auburndale Holdings, LLC
Average availability	Represents the total hours during the period that our plants were in-service or available for service as a percentage of the total hours in the period

ABBREVIATION	DEFINITION
Average capacity factor, excluding peakers	A measure of total actual generation as a percent of total potential generation. It is calculated by dividing (a) total MWh generated by our power plants, excluding peakers, by (b) the product of multiplying (i) the average total MW in operation, excluding peakers, during the period by (ii) the total hours in the period
Bankruptcy Code	U.S. Bankruptcy Code
BLM	Bureau of Land Management of the U.S. Department of the Interior
Blue Spruce	Blue Spruce Energy Center, LLC, an indirect, wholly owned subsidiary that owns Blue Spruce Energy Center, a 310 MW natural gas-fired peaker power plant located in Aurora, Colorado
Broad River	Broad River Energy Center, an 847 MW natural gas-fired peaker power plant located in Gaffney, South Carolina
Btu	British thermal unit(s), a measure of heat content
CAA	Federal Clean Air Act, U.S. Code Title 42, Chapter 85
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CalGen	Calpine Generating Company, LLC, an indirect, wholly owned subsidiary
CalGen Third Lien Debt	Together, the $680,000,000 Third Priority Secured Floating Rate Notes Due 2011, issued by CalGen and CalGen Finance Corp.; and the $150,000,000 11.5% Third Priority Secured Notes Due 2011, issued by CalGen and CalGen Finance Corp., in each case repaid on March 29, 2007
Calpine BRSP	Calpine BRSP, LLC
Calpine Debtors	The U.S. Debtors and the Canadian Debtors
Calpine Equity Incentive Plans	Collectively, the Equity Plan and the Director Plan, which provide for grants of equity awards to Calpine employees and non-employee members of Calpine's Board of Directors
Canadian Court	The Court of Queen's Bench of Alberta, Judicial District of Calgary
Canadian Debtors	The subsidiaries and affiliates of Calpine Corporation that were granted creditor protection under the CCAA in the Canadian Court
Canadian Effective Date	February 8, 2008, the date on which the Canadian Court ordered and declared that the Canadian Debtors' proceedings under the CCAA were terminated
Canadian Settlement Agreement	Settlement Agreement dated as of July 24, 2007, by and between Calpine Corporation, on behalf of itself and its U.S. subsidiaries, Calpine Canada Energy Ltd., Calpine Canada Power Ltd., Calpine Canada Energy Finance ULC, Calpine Energy Services Canada Ltd., Calpine Canada Resources Company, Calpine Canada Power Services Ltd., Calpine Canada Energy Finance II ULC, Calpine Natural Gas Services Limited, 3094479 Nova Scotia Company, Calpine Energy Services Canada Partnership, Calpine Canada Natural Gas Partnership, Calpine Canadian Saltend Limited Partnership and HSBC Bank USA, National Association, as successor indenture trustee

ABBREVIATION	DEFINITION
Cap-and-trade	A government imposed emissions reduction program that would place a cap on the amount of emissions that can be emitted from certain sources, such as power plants. In its simplest form, the cap amount is set as a reduction from the total emissions during a base year and for each year over a period of years the cap amount would be reduced to achieve the targeted overall reduction by the end of the period. Allowances or credits for emissions in an amount equal to the cap would be issued or auctioned to companies with facilities, permitting them to emit up to a certain amount of GHG during each applicable period. After allowances have been distributed or auctioned, they can be transferred, or traded
CARB	California Air Resources Board
CCAA	Companies' Creditors Arrangement Act (Canada)
CCFC	Calpine Construction Finance Company, L.P., an indirect, wholly owned subsidiary
CCFC Finance	CCFC Finance Corp.
CCFC Guarantors	Hermiston Power LLC and Brazos Valley Energy LLC, wholly owned subsidiaries of CCFC
CCFC Notes	The $1.0 billion aggregate principal amount of 8.0% Senior Secured Notes due 2016 issued May 19, 2009, by CCFC and CCFC Finance
CCFC Old Notes	The $415 million total aggregate principal amount of Second Priority Senior Secured Floating Rate Notes Due 2011 issued by CCFC and CCFC Finance, comprising $365 million aggregate principal amount issued August 14, 2003, and $50 million aggregate principal amount issued September 25, 2003, and redeemed, in each case, on June 18, 2009
CCFC Refinancing	The issuance of the CCFC Notes on May 19, 2009, pursuant to Rule 144A and Regulation S under the Securities Act, and the related transactions including repayment of the CCFC Term Loans and the redemption of the CCFC Old Notes and CCFCP Preferred Shares
CCFC Term Loans	The $385 million First Priority Senior Secured Institutional Term Loans due 2009 borrowed by CCFC under the Credit and Guarantee Agreement, dated as of August 14, 2003, among CCFC, the guarantors party thereto, and Goldman Sachs Credit Partners L.P., as sole lead arranger, sole bookrunner, administrative agent and syndication agent, and repaid on May 19, 2009
CCFCP	CCFC Preferred Holdings, LLC
CCFCP Preferred Shares	The $300 million of six-year redeemable preferred shares due 2011 issued by CCFCP and redeemed on or before July 1, 2009
CEHC	Conectiv Energy Holding Company, a wholly owned subsidiary of Conectiv
CES	Calpine Energy Services, L.P.
CFTC	U.S. Commodities Futures Trading Commission
Chapter 11	Chapter 11 of the U.S. Bankruptcy Code

ABBREVIATION	DEFINITION
CO_2	Carbon dioxide
COD	Commercial operations date
Cogeneration	In addition to generating power, using a portion or all of the steam generated in the power generating process to supply a customer with thermal energy, including steam for use in the customer's operations
Commodity Collateral Revolver	Commodity Collateral Revolving Credit Agreement, dated as of July 8, 2008, among Calpine Corporation as borrower, Goldman Sachs Credit Partners L.P., as payment agent, sole lead arranger and sole bookrunner, and the lenders from time to time party thereto, which was repaid on July 8, 2010
Commodity expense	The sum of our expenses from fuel and purchased energy expense, fuel transportation expense, transmission expense and cash settlements from our marketing, hedging and optimization activities that are included in our mark-to-market activity in fuel and purchased energy expense, but excludes the unrealized portion of our mark-to-market activity
Commodity Margin	Non-GAAP financial measure that includes power and steam revenues, sales of purchased power and natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, RGGI compliance and other environmental costs, and cash settlements from our marketing, hedging and optimization activities that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenues
Commodity revenue	The sum of our revenues from power and steam sales, sales of purchased power and natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue, and cash settlements from our marketing, hedging and optimization activities that are included in our mark-to-market activity in operating revenues but excludes the unrealized portion of our mark-to-market activity
Company	Calpine Corporation, a Delaware corporation, and subsidiaries
Conectiv	Conectiv Energy, a wholly owned subsidiary of PHI
Conectiv Acquisition	The acquisition of all of the membership interests in CEHC pursuant to the Conectiv Purchase Agreement on July 1, 2010, whereby we acquired all of the power generation assets of Conectiv from PHI, which include 18 operating power plants and one plant under construction, with approximately 4,490 MW of capacity (including completion of the York Energy Center, formerly known as the Delta Project, under construction and scheduled upgrades)
Conectiv Purchase Agreement	Purchase Agreement by and among PHI, Conectiv, CEHC and NDH dated as of April 20, 2010
Confirmation Order	The order of the U.S. Bankruptcy Court entitled "Findings of Fact, Conclusions of Law, and Order Confirming Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code," entered December 19, 2007, confirming the Plan of Reorganization pursuant to section 1129 of the Bankruptcy Code

ABBREVIATION	DEFINITION
Convertible Senior Notes	Collectively, Calpine Corporation's 4.0% Contingent Convertible Notes Due 2006, Contingent Convertible Notes Due 2014, 7.75% Contingent Convertible Notes Due 2015 and 4.75% Contingent Convertible Senior Notes Due 2023, all of which were terminated and settled with reorganized Calpine Corporation common stock on the Effective Date
Corporate Revolving Facility	The $1.0 billion aggregate amount revolving credit facility credit agreement, dated as of December 10, 2010, among Calpine Corporation, Goldman Sachs Bank USA, as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, the lenders party thereto and the other parties thereto
CPUC	California Public Utilities Commission
Creed	Creed Energy Center, LLC
Deer Park	Deer Park Energy Center Limited Partnership
DIP	Debtor-in-possession
DIP Facility	The Revolving Credit, Term Loan and Guarantee Agreement, dated as of March 29, 2007, among Calpine Corporation, as borrower, certain of Calpine Corporation's subsidiaries, as guarantors, the lenders party thereto, and Credit Suisse, as administrative agent and collateral agent, and the other agents, arrangers and bookrunners named therein
Director Plan	The Amended and Restated Calpine Corporation 2008 Director Incentive Plan
Dodd-Frank Act	The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
EBITDA	Earnings before interest, taxes, depreciation and amortization
Effective Date	January 31, 2008, the date on which the conditions precedent enumerated in the Plan of Reorganization were satisfied or waived and the Plan of Reorganization became effective
EIA	Energy Information Administration of the U.S. Department of Energy
Emergence Date Market Capitalization	The weighted average trading price of Calpine Corporation's common stock over the 30-day period following the date on which it emerged from Chapter 11 bankruptcy protection, as defined in and calculated pursuant to Calpine Corporation's amended and restated certificate of incorporation and reported in its Current Report on Form 8-K filed with the SEC on March 25, 2008
EPA	U.S. Environmental Protection Agency
Equity Plan	The Amended and Restated Calpine Corporation 2008 Equity Incentive Plan
ERCOT	Electric Reliability Council of Texas
EWG(s)	Exempt wholesale generator(s)
Exchange Act	U.S. Securities Exchange Act of 1934, as amended
FDIC	U.S. Federal Deposit Insurance Corporation
FERC	U.S. Federal Energy Regulatory Commission

ABBREVIATION	DEFINITION
First Lien Credit Facility	Credit Agreement, dated as of January 31, 2008, as amended by the First Amendment to Credit Agreement and Second Amendment to Collateral Agency and Intercreditor Agreement, dated as of August 20, 2009, among Calpine Corporation, as borrower, certain subsidiaries of the Company named therein, as guarantors, the lenders party thereto, Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent, and the other agents named therein
First Lien Facilities	Together, our First Lien Credit Facility and $300 million Bridge Loan Agreement dated January 31, 2008 repaid on March 6, 2008
First Lien Notes	Collectively, the 2017 First Lien Notes, the 2019 First Lien Notes, the 2020 First Lien Notes and the 2021 First Lien Notes
FRCC	Florida Reliability Coordinating Council
Fremont	Fremont Energy Center, LLC
Freestone	Freestone Energy Center, a 994 MW natural gas-fired, combined-cycle power plant located near Fairfield, Texas
GE	General Electric International, Inc.
GEC	Collectively, Gilroy Energy Center, LLC, Creed and Goose Haven
Geysers Assets	Our geothermal power plant assets, including our steam extraction and gathering assets, located in northern California consisting of 15 operating power plants and one plant not in operation
GHG(s)	Greenhouse gas(es), primarily carbon dioxide (CO_2), and including methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs)
Gilroy	Calpine Gilroy Cogen, L.P.
Goose Haven	Goose Haven Energy Center, LLC
Greenfield LP	Greenfield Energy Centre LP, a 50% partnership interest between certain of our subsidiaries and a third party which operates the Greenfield Energy Centre, a 1,038 MW natural gas-fired, combined-cycle power plant in Ontario, Canada
Heat Rate(s)	A measure of the amount of fuel required to produce a unit of power
Hg	Mercury
Hillabee	Hillabee Energy Center, LLC
IRC	Internal Revenue Code
ISO(s)	Independent System Operator(s)
ISO NE	ISO New England
KWh	Kilowatt hour(s), a measure of power produced
LIBOR	London Inter-Bank Offered Rate
LSTC	Liabilities subject to compromise
LTSA(s)	Long-Term Service Agreement(s)

ABBREVIATION	DEFINITION
Market Capitalization	As of any date, Calpine Corporation's then market capitalization calculated using the rolling 30-day weighted average trading price of Calpine Corporation's common stock, as defined in and calculated in accordance with the Calpine Corporation amended and restated certificate of incorporation
Market Heat Rate(s)	The regional power price per MWh divided by the corresponding regional natural gas price per MMBtu
Metcalf	Metcalf Energy Center, LLC
MISO	Midwest ISO
MMBtu	Million Btu
MRO	Midwest Reliability Organization
MRTU	CAISO's Market Redesign and Technology Upgrade
MW	Megawatt(s), a measure of plant capacity
MWh	Megawatt hour(s), a measure of power produced
NAAQS	National Ambient Air Quality Standards
NDH	New Development Holdings, LLC, an indirect, wholly owned subsidiary of Calpine Corporation, formed for the acquisition of Conectiv
NDH Project Debt	The $1.3 billion senior secured term loan facility and the $100 million revolving credit facility issued for the Conectiv Acquisition on July 1, 2010 under the credit agreement, dated as of June 8, 2010, among NDH, as borrower, Credit Suisse AG, as administrative agent, collateral agent, issuing bank and syndication agent, Credit Suisse Securities (USA) LLC, Citigroup Global Markets Inc. and Deutsche Bank Securities Inc., as joint bookrunners and joint lead arrangers, Credit Suisse AG, Citibank, N.A., and Deutsche Bank Trust Company Americas, as co-documentation agents and the lenders party thereto
NJDEP	New Jersey Department of Environmental Protection
NERC	North American Electric Reliability Council
NOL(s)	Net operating loss(es)
NO_X	Nitrogen oxides
NPCC	Northeast Power Coordinating Council
NYISO	New York ISO
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OMEC	Otay Mesa Energy Center, LLC, an indirect, wholly owned subsidiary that owns the Otay Mesa Energy Center, a 608 MW power plant located in San Diego County, California
OTC	Over-the-Counter

ABBREVIATION	DEFINITION
PCF	Power Contract Financing, L.L.C.
PCF III	Power Contract Financing III, LLC
Petition Date	December 20, 2005
PG&E	Pacific Gas & Electric Company
PHI	Pepco Holdings, Inc.
PJM	Pennsylvania-New Jersey-Maryland Interconnection
Plan of Reorganization	Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code filed by the U.S. Debtors with the U.S. Bankruptcy Court on December 19, 2007, as amended, modified or supplemented through the filing of this Report
Pomifer	Pomifer Power Funding, LLC, a subsidiary of Arclight Energy Partners Fund I, L.P.
PPA(s)	Any term power purchase agreement or other contract for a physically settled sale (as distinguished from a financially settled future, option or other derivative or hedge transaction) of any power product, including power, capacity and/or ancillary services, in the form of a bilateral agreement or a written or oral confirmation of a transaction between two parties to a master agreement, including sales related to a tolling transaction in which the purchaser provides the fuel required by us to generate such power and we receive a variable payment to convert the fuel into power and steam
PSCo	Public Service Company of Colorado, a wholly owned subsidiary of Xcel Energy Inc.
PUCT	Public Utility Commission of Texas
PUHCA 2005	U.S. Public Utility Holding Company Act of 2005
PURPA	U.S. Public Utility Regulatory Policies Act of 1978
QF(s)	Qualifying facility(ies), which are cogeneration facilities and certain small power production facilities eligible to be "qualifying facilities" under PURPA, provided that they meet certain power and thermal energy production requirements and efficiency standards. QF status provides an exemption from PUHCA 2005 and grants certain other benefits to the QF
REC(s)	Renewable energy credit(s)
Reserve margin(s)	The measure of how much the total generating capacity installed in a region exceeds the peak demand for power in that region
RFC	Reliability *First* Corporation
RGGI	Regional Greenhouse Gas Initiative
RMR Contract(s)	Reliability Must Run contract(s)
RockGen	RockGen Energy LLC
RockGen Owner Lessors	Collectively, RockGen OL-1, LLC; RockGen OL-2, LLC; RockGen OL-3, LLC and RockGen OL-4, LLC

ABBREVIATION	DEFINITION
Rocky Mountain	Rocky Mountain Energy Center, LLC, an indirect, wholly owned subsidiary that owns Rocky Mountain Energy Center, a 621 MW natural gas-fired, combined-cycle power plant located in Keenesburg, Colorado
Rosetta	Rosetta Resources Inc.
RPS	Renewable Portfolio Standards
SDG&E	San Diego Gas & Electric Company
SEC	U.S. Securities and Exchange Commission
Second Circuit	U.S. Court of Appeals for the Second Circuit
Second Priority Debt	Collectively, Calpine Corporation's Second Priority Senior Secured Floating Rate Notes Due 2007, 8.5% Second Priority Senior Secured Notes Due 2010, 8.75% Second Priority Senior Secured Notes Due 2013 and 9.875% Second Priority Senior Secured Notes Due 2011 and Second Priority Senior Secured Term Loans Due 2007; all of which were repaid on the Effective Date
Securities Act	U.S. Securities Act of 1933, as amended
SERC	Southeastern Electric Reliability Council
SO_2	Sulfur dioxide
South Point	South Point Energy Center, a 530 MW natural gas-fired, combined-cycle power plant located in Mohave Valley, Arizona
Spark Spread(s)	The difference between the sales price of power per MWh and the cost of fuel to produce it
SPP	Southwest Power Pool
Steam Adjusted Heat Rate	The adjusted Heat Rate for our natural gas-fired power plants, excluding peakers, calculated by dividing (a) the fuel consumed in Btu reduced by the net equivalent Btu in steam exported to a third party by (b) the KWh generated. Steam Adjusted Heat Rate is a measure of fuel efficiency, so the lower our Steam Adjusted Heat Rate, the lower our cost of generation
Steamboat	Calpine Steamboat Holdings, LLC, an indirect, wholly owned subsidiary of Calpine Corporation
Steamboat Amended Credit Facility	The Amended and Restated Credit Agreement dated November 24, 2009 between Steamboat, as borrower, the lenders named therein, Calyon New York Branch as lead arranger, co-book runner, administrative agent, collateral agent and Security Fund LC issuer and the other agents, bookrunners and agents named therein amending and restating the Credit Agreement, dated as of February 25, 2005, among the parties as defined therein
TRE	Texas Regional Entity
ULC I	Calpine Canada Energy Finance ULC
ULC II	Calpine Canada Energy Finance II ULC

ABBREVIATION	DEFINITION
Unsecured Senior Notes	Collectively, Calpine Corporation's 7.625% Senior Notes due 2006, 10.5% Senior Notes due 2006, 8.75% Senior Notes due 2007, 7.875% Senior Notes due 2008, 7.75% Senior Notes due 2009, 8.625% Senior Notes due 2010 and 8.5% Senior Notes due 2011, all of which were terminated and settled with Calpine Corporation common stock on the Effective Date
U.S. Bankruptcy Court	U.S. Bankruptcy Court for the Southern District of New York
U.S. Debtor(s)	Calpine Corporation and each of its subsidiaries and affiliates that have filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court, which matters are being jointly administered in the U.S. Bankruptcy Court under the caption *In re Calpine Corporation, et al.*, Case No. 05-60200 (BRL)
U.S. GAAP	Generally accepted accounting principles in the U.S.
VAR	Value-at-risk
VIE(s)	Variable interest entity(ies)
WECC	Western Electricity Coordinating Council
Whitby	Whitby Cogeneration Limited Partnership, a 50 MW natural gas-fired, cogeneration power plant in Ontario, Canada (50% equity interest held by our Canadian subsidiaries)
WP&L	Wisconsin Power & Light Company
York Energy Center	565 MW dual fuel, combined-cycle generation power plant (formerly known as the Delta Project) under construction located in Peach Bottom Township, Pennsylvania, included in the Conectiv Acquisition

Forward-Looking Statements

In addition to historical information, this Report contains "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. We use words such as "believe," "intend," "expect," "anticipate," "plan," "may," "will," "should," "estimate," "potential," "project" and similar expressions to identify forward-looking statements. Such statements include, among others, those concerning our expected financial performance and 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 that a number of risks and uncertainties could cause actual results to differ materially from those anticipated in the forward-looking statements. Such risks and uncertainties include, but are not limited to:

- Financial results that may be volatile and may not reflect historical trends due to, among other things, fluctuations in prices for commodities such as natural gas and power, fluctuations in liquidity and volatility in the energy commodities markets and our ability to hedge risks;

- Regulation in the markets in which we participate and our ability to effectively respond to changes in laws and regulations or the interpretation thereof including changing market rules and evolving federal, state and regional laws and regulations including those related to climate change, GHG emissions and derivative transactions;

- The unknown future impact on our business from the Dodd-Frank Act and the rules to be promulgated under it;

- Our ability to manage our liquidity needs and to comply with covenants under our First Lien Notes, Corporate Revolving Facility, NDH Project Debt, CCFC Notes and other existing financing obligations;

- Risks associated with the operation, construction and development of power plants including unscheduled outages or delays and plant efficiencies;

- Risks related to our geothermal resources, including the adequacy of our steam reserves, unusual or unexpected steam field well and pipeline maintenance requirements, variables associated with the injection of wastewater to the steam reservoir and potential regulations or other requirements related to seismicity concerns that may delay or increase the cost of developing or operating geothermal resources;

- Competition, including risks associated with marketing and selling power in the evolving energy markets;

- The expiration or termination of our PPAs and the related results on revenues;

- Future capacity revenues may not occur at expected levels;

- Natural disasters, such as hurricanes, earthquakes and floods, or acts of terrorism that may impact our power plants or the markets our power plants serve and our corporate headquarters;

- Disruptions in or limitations on the transportation of natural gas, fuel oil and transmission of power;

- Our ability to manage our customer and counterparty exposure and credit risk, including our commodity positions;

- Our ability to attract, motivate and retain key employees;
- Present and possible future claims, litigation and enforcement actions; and
- Other risks identified in this Report.

Given the risks and uncertainties surrounding forward-looking statements, you should not place undue reliance on these statements. Many of these factors are beyond our ability to control or predict. Our forward-looking statements speak only as of the date of this Report. Other than as required by law, we undertake no obligation to update or revise forward-looking statements, whether as a result of new information, future events, or otherwise.

Where You Can Find Other Information

Our website is www.calpine.com. Information contained on our website is not part of this Report. Information that we furnish or file with the SEC, including our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to or exhibits included in these reports are available for download, free of charge, on our website soon after such reports are filed with or furnished to the SEC. Our SEC filings, including exhibits filed therewith, are also available at the SEC's website at www.sec.gov. You may obtain and copy any document we furnish or file with the SEC at the SEC's public reference room at 100 F Street, NE, Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the SEC's public reference facilities by calling the SEC at 1-800-SEC-0330. You may request copies of these documents, upon payment of a duplicating fee, by writing to the SEC at its principal office at 100 F Street, NE, Room 1580, Washington, D.C. 20549.

PART I

Item 1. *Business*

BUSINESS AND STRATEGY

Business

We aspire to be recognized as the premier independent wholesale power producer in the U.S. We seek to achieve this objective by delivering operational excellence, effectively executing our hedging strategy, focusing on our customer origination program, completing, on schedule and on budget, our growth capital projects and strengthening our balance sheet. We are the largest independent wholesale power company in the U.S. measured by power produced. We own and operate primarily natural gas-fired and geothermal power plants in North America and have a significant presence in major competitive wholesale power markets in California, Texas and the Mid-Atlantic region of the U.S. Since our inception in 1984, we have been a leader in environmental stewardship. We have invested in clean power generation to become a recognized leader in developing, constructing, owning and operating an environmentally responsible portfolio of power plants. Our portfolio is primarily comprised of two types of power generation technologies: natural gas-fired combustion turbines, which are primarily combined-cycle plants, and renewable geothermal conventional steam turbines. We are among the world's largest owners and operators of industrial gas turbines as well as cogeneration power plants. Our Geysers Assets located in northern California represent the largest geothermal power generation portfolio in the U.S. and produced approximately 21% of all renewable energy in the state of California during 2009. We sell wholesale power, steam, capacity, renewable energy credits and ancillary services to our customers, including utilities, independent electric system operators, industrial and agricultural companies, retail power providers, municipalities and power marketers. We purchase natural gas and fuel oil as fuel for our power plants, engage in related natural gas transportation and storage transactions, and we purchase electric transmission rights to deliver power to our customers. We also enter into natural gas and power physical and financial contracts to hedge certain business risks and optimize our portfolio of power plants.

As part of our initiative to deploy our capital in the most advantageous way for shareholders, the Conectiv Acquisition on July 1, 2010, provided us with a significant presence in the Mid-Atlantic region of the U.S., one of the most robust competitive power markets in the U.S., and positioned us with three scale markets instead of two (California and Texas) giving us greater geographical diversity. We added 18 operating power plants and one plant under construction, with approximately 4,490 MW of capacity (including completion of the York Energy Center under construction and scheduled upgrades). Approximately 340 MW of the power plants acquired have conventional steam turbine technology where coal was used as the primary fuel source prior to our acquisition of them. These power plants are also capable of burning natural gas or fuel oil to generate power. At the close of this acquisition, under our environmental leadership, these plants ceased burning coal, and we do not intend to burn coal to generate power from these power plants in the future. Instead, we generate power from these power plants using natural gas and plan to modernize these sites in the longer term to more efficient natural gas-fired combustion turbines.

Our portfolio, including partnership interests, includes 91 operating power plants, located throughout 20 states in the U.S. and Canada, with an aggregate generation capacity of 27,490 MW and 1,149 MW under construction. Our generation capacity includes approximately 5,241 MW of baseload capacity from our Geysers Assets and cogeneration power plants, 15,838 MW of intermediate load capacity from our combined-cycle combustion turbines, 6,411 MW of peaking capacity from our simple-cycle combustion turbines and duct-fired capability, which includes approximately 4 MW of capacity from solar, photovoltaic power generation technology located in New Jersey included in our North segment. We have an aggregate generation capacity of 6,886 MW with an additional 584 MW under construction in the West, 7,185 MW in Texas, 7,336 MW with an additional 565 MW under construction in the North and 6,083 MW in the Southeast. Our Geysers Assets, included in our West segment, have generation capacity of approximately 725 MW from 15 operating geothermal power plants, and we have begun expansion efforts to increase our generation capability at our Geysers Assets.

The environmental profile of our power plants reflects our commitment to environmental leadership and stewardship. We have invested the necessary capital to develop a power generation portfolio that has substantially lower air pollutant emissions compared to our competitors' power plants using other fossil fuels, such as coal. In addition, we strive to preserve our nation's valuable water and land resources. To condense steam, our combined-cycle power plants use cooling towers with a closed water cooling system, or air cooled condensers and do not employ "once-through" water cooling, which uses large quantities of water from adjacent waterways negatively impacting aquatic life. Since our plants are modern and efficient and utilize clean burning natural gas, we do not require large areas of land for our power plants nor do we require large specialized landfills for the disposal of coal ash or nuclear plant waste. We believe that we will be less adversely impacted by cap-and-trade limits, carbon taxes or required environmental upgrades as a result of future potential regulation or legislation addressing GHG, other air pollutant emissions, as well as water use or emissions, than compared to our competitors who use other fossil fuels or older, less efficient technologies.

We remain focused on increasing our earnings and generating cash flow sufficient to maintain adequate levels of liquidity in order to service our debt, meet our collateral needs and fund our operations and growth. We will continue to pursue opportunities to improve our fleet performance and reduce operating costs. In order to manage our various physical assets and contractual obligations, we will continue to execute commodity hedging agreements within the guidelines of our commodity risk policy. Our fleet of natural gas-fired turbines is one of the youngest in the U.S. among large independent power producers and utilities, with a weighted average age, based upon MW capacities in operation, of about eleven years. As a result, in the near term we do not expect that it will be necessary to invest significant expenditures for environmental retrofits or repowering projects to comply with current or reasonably anticipated GHG, other air emissions or water regulations. Our power plants taken as a whole or by region, have an effective Heat Rate lower than that of our major competitors, which we believe gives us a competitive edge in markets such as Texas, California and Mid-Atlantic where natural gas-fired generation generally sets the market price for power.

We sell a substantial portion of our power and other products under PPAs with a duration greater than one year. The contracted sale of power, steam and capacity from our cogeneration power plants, combustion turbine power plants and geothermal power plants, as well as the sale of renewable energy credits, or RECs, from our geothermal power plants, provide a stable source of revenue. Our portfolio also affords us the flexibility to sell power and other products forward for shorter terms or on a merchant basis into the spot markets, where we are able to realize attractive pricing particularly during peak demand periods. Additionally, we sell capacity or similar products to retail power providers, utilities, municipalities and others required to acquire capacity and similar products by regulatory or market rules, and we sell ancillary services to independent system operators and utilities to support power transmission system reliability. We have substantially hedged our Commodity Margin for 2011.

Our principal offices are located in Houston, Texas with regional offices in Dublin, California and Wilmington, Delaware, an engineering, construction and maintenance services office in Pasadena, Texas and government affairs offices in Washington D.C., Sacramento, California and Austin, Texas. We operate our business through a variety of divisions, subsidiaries and affiliates.

Strategy

Our goal is to be recognized as the premier independent power company in the U.S. as measured by our shareholders, customers and regulators as well as the communities in which our power plants are located. We seek to achieve sustainable growth through financially disciplined power plant development, construction, acquisition, operation and ownership. Our strategy to achieve this is reflected in the five major initiatives described below:

1. *Premier Operating Company* — Our objective is to be the "best-in-class" in regards to certain operational performance metrics, such as safety, availability, reliability, efficiency and cost management.

   - Throughout 2010, our plant operating personnel exceeded the first quartile performance for employee lost time incident rate for fossil fuel electric power generation companies with 1,000 or more employees.

   - Our natural gas-fired fleet achieved a forced outage factor of 3.1%. During 2010, we also completed 15 major inspections and 12 hot gas path inspections.

   - For the past ten consecutive years, our Geysers Assets have generated approximately 6 million MWh per year and, in 2010, achieved an exceptional availability factor of over 98%.

   - Since 2008, we have reduced our plant operating and sales, general and administrative expenses, on a comparable basis, by over $100 million.

2. *Leader in Environmental Responsibility* — Our focus is to utilize our modern, efficient fleet to deliver low environmental impact energy solutions relative to other fossil fuel generation as part of our commitment to environmental stewardship. Some examples that demonstrate this commitment include:

   - Approximately 340 MW of the power plants purchased in the Conectiv Acquisition have conventional steam turbine technology where coal was used as the primary fuel source prior to our acquisition of them. These power plants are also capable of burning natural gas or fuel oil to generate power. At the close of the Conectiv Acquisition, under our environmental leadership, these plants ceased burning coal, and we do not intend to burn coal to generate power from these plants in the future.

   - Our strong and continuing commitment to environmental responsibility and leadership is exemplified by our development of the Russell City Energy Center. Russell City Energy Center is under construction and is intended to become the first power plant in the U.S. with a federal limit on GHG emissions, and will be designed to operate in a way that produces 25% fewer GHG emissions than the CPUC standard. The power plant will use 100% reclaimed water from the City of Hayward's Water Pollution Control Facility for cooling and boiler makeup, which will prevent nearly four million gallons of wastewater per day from being discharged into the San Francisco Bay. We initiated and agreed to accept the GHG permit limit and designed the plant to benefit local water resources.

   - We continue to actively participate in legislative and regulatory processes addressing environmental concerns and support legislative and regulatory action to address climate change, GHG and other air emissions from fossil fuel generation. We intend to leverage our baseload geothermal expertise to grow our renewable energy portfolio.

3. *Enhancing Shareholder Value* — In addition to our Conectiv Acquisition, we have completed significant financing transactions that have improved our capital structure and financial flexibility, and strengthened our balance sheet. Our efforts have delivered significant results.

We have repositioned our asset base:

- Our Conectiv Acquisition added $1.64 billion in net assets with $1.3 billion in project debt. The remaining amounts were funded with operating cash on hand.

- We sold 100% of our ownership interests in Blue Spruce and Rocky Mountain for approximately $739 million, resulting in a pre-tax gain of approximately $209 million. The sales proceeds received were used to repay $418 million in project debt and the remaining funds will be used to fund future development and growth in our core markets.

- We sold a 25% undivided interest in the assets of our Freestone power plant for approximately $215 million in cash. We recorded a pre-tax gain on sale of approximately $119 million. The sales proceeds received will be used to fund future development and growth in our core markets.

We have continued to de-risk and simplify our capital structure:

- The most significant of our 2010 and early 2011 financing transactions was the issuance of the new First Lien Notes, termination of the First Lien Credit Facility and extension of our debt maturities. Beginning in the fourth quarter of 2009 through January of 2011, we issued First Lien Notes in a series of tranches with maturity dates in 2017, 2019, 2020, 2021 and 2023. The proceeds from those issuances, together with operating cash, were used to fully repay all of our outstanding term loan borrowings under our First Lien Credit Facility, thereby terminating the First Lien Credit Facility in accordance with its terms. The termination of the First Lien Credit Facility eliminated the more restrictive of our debt covenants, resulting in increased operational, strategic and financial flexibility in managing our capital resources including the flexibility to reinvest more earnings for organic growth, issue and/or buyback shares of our common stock, pay dividends and incur additional debt, if needed, for acquisitions or development. Additionally, we significantly smoothed and extended contractual debt maturities of approximately $4.7 billion (as of December 31, 2009), due in 2014, such that no more than $2.0 billion of our corporate debt matures in any one year.

- On December 10, 2010, we executed our $1.0 billion Corporate Revolving Facility, which replaced our $1.0 billion revolver under our First Lien Credit Facility and allows for up to $750 million of availability for the issuance of letters of credit and up to $50 million as a swingline subfacility. The Corporate Revolving Facility may be utilized for working capital requirements and other general corporate purposes.

We are committed to allocate and invest capital prudently:

- We will continue to grow our business in an economically and financially disciplined manner.

- We may reduce our debt by repayment of some of our project financing or early repayment of our First Lien Notes.

4. *Leverage our Three Scale Regions* — Our goal is to continue to grow our presence in core markets with an emphasis on expansions or upgrades of existing power plants. We intend to take advantage of favorable opportunities to continue to design, develop, acquire, construct and operate the next generation of highly efficient, operationally flexible and environmentally responsible power plants where such investment meets our rigorous financial hurdles, particularly if power contracts and financing are available and attractive returns are expected. We will consider selective acquisitions or additions of new capacity supported by long-term hedging programs, including PPAs and natural gas tolling agreements, particularly where attractive financing is available. In addition, we believe that upgrades and expansions

to our current assets offer proven and financially disciplined opportunities to improve our operations, capacity and efficiencies. Our significant projects under construction, growth initiatives and upgrades are discussed below.

- *York Energy Center* — We acquired the York Energy Center, a 565 MW dual fuel, combined-cycle power plant under construction in Peach Bottom Township, Pennsylvania, as part of the Conectiv Acquisition. All permits have been received and COD is expected in March 2011, three months early and approximately $20 million under budget. The York Energy Center will sell power under a six-year PPA with a third party.

- *Russell City Energy Center* — The Russell City Energy Center, continues to move forward and is currently contracted to deliver its full output to PG&E under a ten year PPA. We are in possession of all required approvals and permits, subject to on-going judicial appeals, and the expected COD is in 2013. Upon completion, this project will bring on line approximately 429 MW of net interest baseload capacity (464 MW with peaking capacity) representing our expected 75% ownership share. We began construction in 2010, and we are in the process of obtaining project financing.

- *Los Esteros* — During 2009, we and PG&E negotiated a new PPA to replace the existing California Department of Water Resources contract and facilitate the upgrade of our Los Esteros Critical Energy Facility from a 188 MW simple-cycle generation power plant to a 308 MW combined-cycle generation power plant, which will also increase the efficiency and environmental performance of the power plant by lowering the Heat Rate. The PPA and related agreements with PG&E have received all of the necessary approvals and the California Energy Commission has renewed our license and emission limits, but the appeal period has not yet expired. We are in the process of procuring equipment and selecting the engineering, procurement and construction contractors. We expect COD during the third quarter of 2013.

- *Turbine Upgrades* — We continue to move forward with our turbine upgrade program and have entered into an agreement to upgrade select GE and Siemens turbines. Through January 2011, we have completed the upgrade of six Siemens turbines and have agreed to upgrade approximately 15 additional Siemens and GE turbines (and may upgrade additional turbines in the future). Our turbine upgrade program is expected to increase our generation capacity in total by approximately 275 MW. This upgrade program began in the fourth quarter of 2009 and is scheduled through 2014. The upgraded turbines have been operating with Heat Rates falling in line with expectations.

- *Geysers Assets Expansion* — We continue to look to expand our production from our Geysers Assets. Beginning in the fourth quarter of 2009, we conducted an exploratory drilling program, which effectively proved the commercial viability of the steam field in the northern part of our Geysers Assets; however, permitting delays have emerged that we are working to resolve. We were planning to target a 2013 COD for an expansion of our Geysers Assets and had been, in parallel, negotiating commercial arrangements to support that, but the permitting delay has increased the risk we will not meet a target 2013 COD. We continue to believe our northern Geysers Assets have potential for development. In the near term, we will work to connect the test wells we have drilled over the last year to our existing power plants and will work to capture incremental MW from those wells, while continuing with the permitting process, baseline engineering work and sales efforts for an expansion target COD subsequent to 2013.

5. *Customer-Oriented Origination Business* — We reorganized our customer origination function to allow a dedicated group of professionals to more effectively manage our forward power sales. Their charter is to understand our customers' wants and needs and to rally our organization to develop unique, cost-effective solutions that benefit us and our customers. This effort has delivered real, tangible results.

A summary of some of the significant new contracts entered into or approved in 2010 are as follows:

- We received approval of our PPA contracts totaling 1,250 MW with SDG&E and PG&E from the CPUC.
- We have entered into a new seven-year PPA with Xcel Energy to provide 200 MW of power generated by our Oneta Energy Center to Southwestern Public Service Company, a subsidiary of Xcel Energy.
- We sold 100% of our ownership interests in Blue Spruce and Rocky Mountain and a 25% undivided interest in the assets of our Freestone power plant as described above.
- We have entered into a PPA with Bonneville Power Administration to provide up to 75 MW of wind power generation flexibility.

The last transaction is an indication of the growing need our customers, and more generally the market, have to utilize flexible natural gas-fired generation to integrate into the grid supply from intermittent and variable renewable resources, such as wind and solar power, that they are required to procure as part of a renewable energy portfolio, while assuring reliability.

THE MARKET FOR POWER

Our Power Markets and Market Fundamentals

The power industry represents one of the largest industries in the U.S. and impacts nearly every aspect of our economy, with an estimated end-user market of approximately $370 billion in power sales in 2010 according to the EIA. Historically, vertically integrated power utilities with monopolies over franchised territories dominated the power generation industry in the U.S. Over the last 25 years, industry trends and regulatory initiatives, culminating with the deregulation trend of the late 1990's and early 2000's, provided opportunities for independent wholesale power producers to compete to provide power. Although different regions of the country have very different models and rules for competition, the markets in which we operate have some form of wholesale market competition. California (included in our West segment), Texas and the Mid-Atlantic (included in our North segment), which are three of our largest markets, have emerged as among the most competitive wholesale power markets in the U.S. We also operate, to a lesser extent, in the competitive ISO NE, NYISO and MISO markets. We produce several products for sale to our customers.

- First, we produce power for sale to utilities, municipalities, retail power providers, independent electric system operators, large end-use industrial or agricultural customers or power marketers. Our power sales occur in several different product categories including baseload (around the clock generation), intermediate (generation typically more expensive than baseload and utilized during higher demand periods to meet shifting demand needs), and peaking capacity (most expensive variable cost and utilized during the highest demand periods), for which the latter is provided by some of our stand alone peaker power plants/units and from our combined-cycle power plants by using technologies such as steam injection or duct firing additional burners in the heat recovery steam generators.
- Second, our cogeneration power plants produce steam for sale to customers for use in industrial or other heating, ventilation and air conditioning operations.
- Third, we provide regulatory capacity for sale to retail power providers. In various markets, retail power providers are required to demonstrate adequate resources to meet their power sales commitments. To meet this obligation, they procure a market product known as capacity. Most electricity market administrators have acknowledged that an energy only market does not provide sufficient revenues to enable existing merchant generators to recover all of their costs or to encourage

new generating capacity to be constructed. Capacity auctions have been implemented in the northeast, the Mid-Atlantic and some mid-west regional markets to address this issue. California has a bilateral capacity program. Texas does not presently have a capacity market.

- Fourth, we provide ancillary service products to wholesale power markets. These products include the right for the purchaser to call on our generation to provide flexibility to the market and support operation of the electric grid. As an example, we are sometimes paid to reserve a portion of some capacity at some of our power plants that could be deployed quickly should there be an unexpected increase in load or to assure reliability due to fluctuations in the supply of power from variable renewable resources such as wind and solar generation.

- Fifth, we sell RECs from our Geysers Assets in northern California, as well as from our small solar power plant in New Jersey. California has an RPS that requires load serving entities to have RECs for a certain percentage of their demand for the purpose of guaranteeing a certain level of renewable generation in the state. Because geothermal is a renewable source of energy, we receive a REC for each MWh we produce and are able to sell our RECs to load serving entities. New Jersey has a solar specific RPS which enables us to sell RECs from our Vineland Solar Energy Center.

In addition to the five products above, we are buyers and sellers of environmental allowances and credits, including those under RGGI, the federal Acid Rain and Clean Air Interstate Rule programs and emission reduction credits under the federal Nonattainment New Source Review program.

Although all of the products mentioned above contribute to our financial performance and are the primary components of our Commodity Margin, the most important is our sale of wholesale power. As our Commodity Margin is largely determined by the pricing associated with our customer contracts, we utilize long term customer contracts for our power and steam sales where possible. For power that is not sold under customer contracts, the short-term and spot market supply and demand fundamentals determine the sale price for our power.

For sales of power from our natural gas-fired fleet into the short-term or spot markets, we attempt to maximize our operations when the market Spark Spread is positive. Assuming economic behavior by market participants, generating units generally are dispatched in order of their variable costs, with lower cost units being dispatched first and units with higher costs dispatched as demand, or "load," grows beyond the capacity of the lower cost units. For this reason, in a competitive market, the price of power typically is related to the variable operating costs of the marginal generator, which is the last unit to be dispatched in order to meet demand. The market factors that most significantly impact our operations are reserve margins, the price and supply of natural gas, weather patterns and natural events, our operating Heat Rate and Availability and regulatory and environmental pressures as further discussed below.

Reserve Margins

Reserve margin, a measure of how much excess generation capacity is present in a market, is a key indicator of the competitive conditions in the markets in which we operate. For example, a reserve margin of 15% indicates that supply is 115% of expected peak power demand. Holding other factors constant, lower reserve margins typically lead to higher power prices because the less efficient capacity in the region would be needed more often to satisfy power demand. Markets with tight demand and supply conditions often display price spikes and improved bilateral contract opportunities. Typically, the market price impact of reserve margins, as well as other supply/demand factors, is reflected in the Market Heat Rate calculated as the local market power price divided by the local natural gas price.

During 2009, the general supply and demand fundamentals were negatively impacted by the combination of recent new generation coming on line (particularly in Texas) and a general decline in weather normalized load year-over-year due to the economic recession. In 2010, we generally experienced a return to weather normalized load growth without a significant increase of generation capacity except for Texas where 1,984 MW of new capacity came on line. Although uncertainty exists and there are key regional differences at a macro level, continued economic recovery and thus, corresponding load recovery, with the lack of broad new power plant investments in our key markets should lead to lower reserve margins and higher market Heat Rates. Reserve margins by NERC region for each of our segments are listed below:

	2011(1)	2010(1)
West:		
WECC	35.1%	29.2%
Texas:		
TRE	15.0%	20.5%
North:		
NPCC	23.1%	22.2%
MRO	30.0%	28.7%
RFC	28.9%	28.1%
Southeast:		
SERC	26.8%	26.5%
SPP	27.6%	24.0%
FRCC	27.1%	25.7%

(1) Data source is EIA

The Price and Supply of Natural Gas

Our fuel requirements are predominantly met with natural gas. While we have approximately 725 MW capacity from our Geysers Assets, our steam flow decline rates have become very small over the past several years and our expectation is that the steam reservoir at our Geysers Assets will be able to supply economic quantities of steam for the foreseeable future. We also have approximately 364 MW of capacity from power plants where we purchase fuel oil to meet these generation requirements, but do not expect fuel oil requirements to be material to our portfolio of power plant assets. Additionally, we have 4 MW of capacity from solar power generation technology with no fuel requirement.

We procure natural gas from multiple suppliers and transportation sources. Although availability is generally not an issue, localized shortages (especially in extreme weather conditions), transportation availability and supplier financial stability issues can and do occur.

Lower gas prices over the past two years have had a significant impact on power markets. Beginning in 2009, there was a significant decrease in natural gas prices from a range of \$6/MMBtu — \$13/MMBtu during 2008 to a range that generally fluctuated between \$3.31/MMBtu — \$5.68/MMBtu during 2009 and 2010. Natural gas prices in some parts of the country for parts of 2009 and 2010 were low enough that modern combined-cycle natural gas-fired generation became less expensive on a marginal basis than coal-fired generation. The result was that natural gas displaced coal as a less expensive generation resource resulting in what the industry describes as coal-to-gas switching.

Although some of this lower pricing dynamic can be attributed to the economic recession, the availability of non-conventional natural gas supplies, in particular shale gas, has also kept gas prices low. The availability of these non-conventional natural gas supplies, in particular from the emergence of significant deposits of shale natural gas, has altered the natural gas supply landscape in the U.S. which could have a longer-term and profound impact on both the outright price of natural gas and the historical regional gas price relationship (basis differential). The U.S. Department of Energy estimates that shale gas production has the potential of 3 trillion to 4 trillion cubic feet per year and may be sustainable for decades with enough natural gas to supply the U.S. for the next 90 years. Accordingly, there is an emerging view of potentially lower priced natural gas for the medium to long-term future. Lower natural gas prices relative to those seen over the last several years may adversely impact our Commodity Margin in the short term as our cost of production advantage relative to less efficient natural gas-fired generation is diminished on an absolute basis, but is expected to provide a more robust environment for natural gas-fired power generation compared to coal-fired, nuclear and renewable generation over the longer-term.

Much of our generating capacity is in California (included in our West segment), Texas and the Mid-Atlantic (included in our North segment) where natural gas-fired units set power prices during most hours or most "peak" hours. "Peak" hours are generally considered between the hours of 7:00 a.m. and 11:00 p.m., with the remaining hours considered "off-peak." In California and Texas, natural gas-fired units set prices during most hours, although incremental renewable generation has moderated this dynamic somewhat in off-peak hours over the last year. In the Mid-Atlantic, natural gas-fired units set prices during most peak hours. Due to natural gas prices generally (although not always) being higher than most other input fuels, these regions generally have higher power prices than regions where coal-fired units set power prices for more hours. Outside of our California, Texas and Mid-Atlantic markets, coal-fired power plants, tend to set power prices more often, reducing average prices and our Commodity Margin.

In markets where natural gas is often the price-setting fuel, such as in Texas, California and the Mid-Atlantic, increases in natural gas prices may increase our unhedged Commodity Margin because our combined-cycle power plants in those markets are more fuel-efficient than conventional gas-fired technologies and peaker power plants. Conversely, decreases in natural gas prices tend to decrease our unhedged Commodity Margin. In other cases, changes in natural gas prices can have a neutral impact on us in the short term, such as where we have entered into tolling agreements under which the customer provides the natural gas and we convert it to power for a fee, or where we enter into indexed-based agreements with a contractual Heat Rate at or near our actual Heat Rate for a monthly payment. Changes in natural gas prices may also affect our liquidity as we could be required to post additional cash collateral or letters of credit during periods of high or volatile natural gas prices. Despite some of these short-term dynamics, over the long run, more moderate natural gas prices may actually enhance the competitiveness of our modern, natural gas-fired fleet by making investment in other technologies such as coal, nuclear, or renewables less economic.

Weather Patterns and Natural Events

Weather could have a significant short-term impact on supply and demand for power and natural gas. Historically, demand for and the price of power is higher in the summer and winter seasons when temperatures are more extreme, and therefore, our unhedged revenues and Commodity Margin could be negatively impacted by relatively cool summers or mild winters. In 2010, we significantly benefited from the Conectiv Acquisition in our North segment, which experienced very hot weather immediately following closing of the acquisition on July 1, which somewhat compensated for milder weather in our West segment and lower general demand. Additionally, a disproportionate amount of our total revenue is usually realized during the summer months of our third fiscal quarter. We expect this trend to continue in the future as U.S. demand for power generally peaks during this time.

Operating Heat Rate and Availability

Our fleet is modern and more efficient than the average generation fleet; accordingly, we run more and earn incremental margin in markets where less efficient natural gas units frequently set the power price. In such cases, our unhedged margin is positively correlated with how much more efficient our fleet is than our competitors' fleets and with higher natural gas prices. Efficient operation of our fleet creates the opportunity to capture Commodity Margin. However, unplanned outages during periods when Commodity Margin is positive can result in a loss of that opportunity. We measure our fleet performance based on our operating Heat Rate and availability factors. The higher our availability factor, the better positioned we are to capture Commodity Margin. The lower our operating Heat Rate compared to the Market Heat Rate, the more favorable the impact on our Commodity Margin.

Regulatory and Environmental Pressures

We believe that, on a net basis, we will be favorably impacted by regulatory factors including those described below, given the characteristics of our power plant portfolio:

- An increase in power generated from renewable sources could lead to an increased need for flexible power that many of our power plants provide to protect reliability of the grid; however, risks also exist that renewables have the ability to lower overall wholesale prices which could negatively impact us. Significant economic and reliability concerns for renewable generation have slowed their growth in 2010 compared to 2009, but we expect that renewable market penetration will continue assisted by technological improvements.

- Environmental pressures continue to increase for coal-fired power generation as state and federal agencies enact rules to reduce air emissions of certain pollutants such as SO_2, NO_X, GHG, Hg and acid gases, restrict the use of once-through cooling, and provide for stricter standards for managing coal combustion residuals. Some of the regions in which we operate include older, less efficient fossil-fuel power plants that emit much higher amounts of GHG, SO_2, NO_X, Hg and acid gases, which we anticipate will be more negatively impacted by future air emissions, water and waste regulations and legislation. The estimated capacity for fossil-fueled plants which are older than 50 years by NERC region are as follows:

West:	
WECC	6,087 MW
Texas:	
TRE	3,272 MW
North:	
NPCC	6,249 MW
MRO	4,214 MW
RFC	25,709 MW
Southeast:	
SERC	26,624 MW
SPP	4,632 MW
FRCC	922 MW
Total	77,709 MW

- Utilities are increasingly focused on demand side management – managing the level and timing of power usage with "smart grid" technologies that improve the efficiencies, dispatch usage and reliability of electric grids; and

- Environmental permitting requirements for new power plants, including those in California, one of our major markets, are becoming increasingly onerous for power plants and transmission lines.

With the exception of demand side management, these trends are positive for our fleet. For a discussion of federal, state and regional legislative and regulatory initiatives and how they might affect us, see "— Governmental and Regulatory Matters."

It is very difficult to predict the continued evolution of our markets due to the uncertainty of the following:

- number of market participants;

- amount of power available in the market;

- fluctuations in power supply due to planned and unplanned outages of generators;

- fluctuations in power demand due to weather and other factors;
- cost of fuel, which could be impacted by the efficiency of generation technology and fluctuations in fuel supply or interruptions in natural gas transportation;
- relative ease or difficulty of developing, permitting and constructing new power plants;
- availability and cost of power transmission;
- creditworthiness and other risks associated with counterparties;
- bidding behavior of market participants;
- regulatory and ISO guidelines and rules;
- structure of commercial products; and
- ability to optimize the market's mix of alternative sources of power such as renewable and hydroelectric power.

Competition

Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. We compete against other independent power producers, power marketers or trading companies, including those owned by financial institutions, retail load aggregators, municipalities, retail power providers, cooperatives and regulated utilities to supply power and power-related products to our customers in major markets in the U.S. and Canada. In addition, in some markets, we compete against some of our customers.

In less regulated markets, such as California, Texas and the Mid-Atlantic, our natural gas-fired power plants compete directly with all other sources of power. The EIA estimates that in 2010, 24% of the power generated in the U.S. was fueled by natural gas and that approximately 65% of power generated in the U.S. was produced by coal and nuclear facilities, which generated approximately 45% and 20%, respectively. The EIA estimates that the remaining 11% of power generated in the U.S. was fueled by hydroelectric, fuel oil and other energy sources. 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 power plants. Federal and state legislative and regulatory actions continue to change. The federal government is expected to continue to take action on many air pollutant emissions such as NO_X, SO_2, Hg and acid gases as well as on once-through cooling and coal ash disposal. Although we cannot predict the ultimate effect any future environmental legislation or regulations will have on our business, as a clean energy provider, we believe that we are well positioned for almost any increase in environmental rule stringency. We are actively participating in these debates at the federal, regional and state levels. For a further discussion of the environmental and other governmental regulations that affect us, see "— Governmental and Regulatory Matters."

As environmental regulations evolve, the proportion of power generated by natural gas and other low emissions resources is expected to increase because older coal-fired power plants will likely have to install costly emission control devices, limit their operations or retire. Meanwhile, the federal government and many states are considering or have already mandated that certain percentages of power delivered to end users in their jurisdictions be produced from renewable resources, such as geothermal, wind and solar energy.

Competition from other sources of power, such as nuclear energy and renewables, is expected to increase in the future, but perhaps at a lower rate than had been expected in 2008 or 2009. The combination of emerging air emissions regulations, federal and state financial incentives and RPS requirements for renewables and their impact of expected increased investment in cleaner sources of generation will be somewhat counteracted by a lower gas price environment, which, should it persist, could make new investment in these types of power generation uneconomical. However, it is doubtful that generation from new nuclear power plants and renewable sources will be available in the quantities needed to meet future energy demand. Beyond economic issues, there are concerns over the reliability and adequacy of transmission infrastructure to transmit certain renewable generation from its source to where it is needed. Consequently, longer-term, natural gas is likely still needed as baseload and "back-up" generation.

We believe our ability to compete will be driven by the extent to which we are able to accomplish the following:

- maintain excellence in operations;
- achieve and maintain a lower cost of production, primarily by maintaining unit availability and efficiency;
- benefit from future environmental regulation and legislation;
- accurately assess and effectively manage our risks; and
- provide reliable service to our customers.

MARKETING, HEDGING AND OPTIMIZATION ACTIVITIES

Our hedging strategy focuses first on protecting our balance sheet, given our debt obligations, our committed capital expenditures and other obligations. Secondly, our hedge efforts attempt to maximize our risk adjusted Commodity Margin by leveraging our knowledge, experience and fundamental views on gas and power. We actively manage and limit our commodity price risk with a variety of tools, including PPAs and other long-term contracts for the sale of power and steam. We also pursue other long-term sales opportunities, as well as shorter term market transactions, including bilateral originated sales contracts, and purchase and sale of exchange-traded instruments. We actively monitor risks such as Market Heat Rate and natural gas price exposure, as well as other risks related to the value of our generation such as regulatory capacity and geographic locational risk in both power and natural gas, REC and emission credit pricing. The relative quantity of our products hedged or sold under longer term contracts is determined by our need to manage our liquidity, the availability of forward product sales opportunities, and our view of the attractiveness of the pricing available for forward sales or through hedging. It is our strategy to seek stronger bilateral relationships under long term contracts with load serving entities that can benefit us and our customers.

The majority of our marketing, hedging and optimization activities are related to risk exposures that arise from our ownership and operation of power plants. We are one of the largest consumers of natural gas in the U.S. having consumed approximately 665 Bcf (billion cubic feet) during 2010. Most of the power generated by our power plants is sold, scheduled and settled by our energy marketing unit, which sells to entities such as utilities, municipalities and cooperatives, as well as to retail power providers, commercial and industrial end users, financial institutions, power trading and marketing companies and other third parties. We enter into physical and financial purchase and sale transactions as part of our marketing, hedging and optimization activities. Our marketing, hedging and optimization activities endeavor to protect and enhance our Commodity Margin. We have approximately 364 MW of capacity from power plants that have flexibility as to fuel source where we purchase fuel oil to meet these generation requirements; however, we have not currently entered into any hedging or optimization transactions for our fuel oil requirements as we do not expect fuel oil requirements to be material to us, but may elect to do so in the future.

Along with our portfolio of hedging transactions, we enter into power and natural gas positions that often act as hedges to our asset portfolio, but do not qualify as hedges under hedge accounting guidelines, such as commodity options transactions and instruments that settle on power price to natural gas price relationships (Heat Rate swaps and options). While our selling and purchasing of power and natural gas is mostly physical in nature, we also engage in marketing, hedging and optimization activities, particularly in natural gas, that are financial in nature. We use derivative instruments, which include physical commodity contracts and financial commodity instruments such as OTC and exchange traded swaps, futures, options, forward agreements and instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) for the purchase and sale of power, natural gas, and emission allowances to manage commodity price risk and to maximize the risk-adjusted returns from our power and natural gas assets.

While we enter into these transactions primarily to provide us with improved price and price volatility transparency, as well as greater market access, which benefits our hedging activities, we also are exposed to commodity price movements (both profits and losses) in connection with these transactions. These positions are included in and subject to our consolidated risk management portfolio position limits and controls structure. We conduct these hedging and optimization activities within a structured risk management framework based on controls, policies and procedures. We monitor these activities through active and ongoing management and oversight, defined roles and responsibilities, and daily risk measurement and reporting. Additionally, we seek to manage the associated risks through diversification, by controlling position sizes, by using portfolio position limits and by entering into offsetting positions that lock in a margin.

We have historically used interest rate swaps to manage the interest rate risk of our variable rate debt. When we repaid the First Lien Credit Facility terms loans, which were variable rate debt, with issuances of First Lien Notes, an evaluation was performed consistent with our risk management policy, and we determined that, based upon current market conditions, liquidation of the interest rate swaps hedging our First Lien Credit Facility term loans was not economically beneficial at this time. We have elected to retain and hold the interest rate swap positions with a notional amount of approximately $3.3 billion as of December 31, 2010 and approximately $4.3 billion in notional amount as of the date of this Report. We may elect to liquidate these positions in the future should interest rates increase.

We have VAR limits that govern the overall risk of our portfolio of power plants, energy contracts, financial hedging transactions and other contracts. Our VAR limits, transaction approval limits and other risk related controls, are dictated by our commodity risk policy which is approved by our Board of Directors and by our Risk Management Committee comprised of members of our senior management and administered by our Chief Risk Officer and his organization. The Chief Risk Officer's organization is segregated from the commercial operations unit and reports directly to our Audit Committee and Chief Executive Officer. Our risk management policies limit our hedging activities to protect and optimize the value of our physical assets. While this policy limits our potential upside from hedging activities, it is primarily intended to provide us with a degree of protection from significant downside energy commodity price exposure to our cash flows.

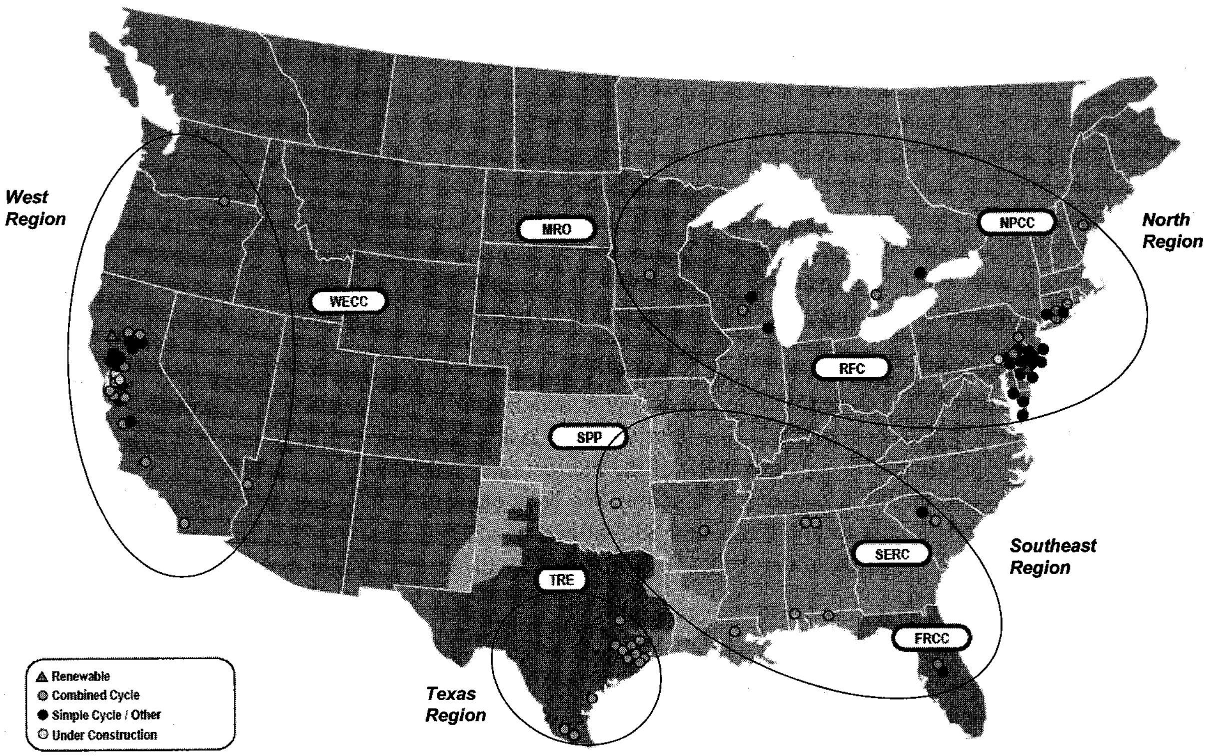
We actively monitor and hedge our exposure to market risks. As of December 31, 2010, we have economically hedged a substantial portion of our generation and natural gas portfolio mostly through power and natural gas forward physical and financial transactions for 2011; however, we are less hedged and remain susceptible to significant commodity price movements for 2012 and beyond. By entering into these transactions, we are able to economically hedge a portion of our Spark Spread at pre-determined generation and price levels. Our future hedged status and marketing and optimization activities are subject to change as determined by our commercial operations group, Chief Risk Officer, Risk Management Committee of senior management and Board of Directors.

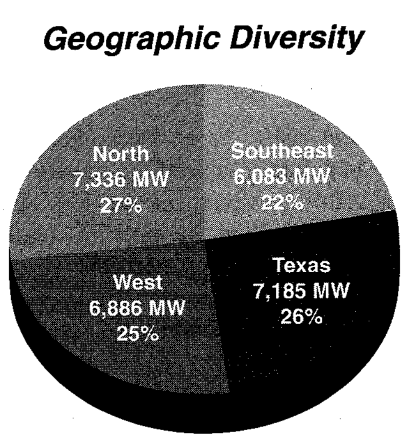
Seasonality and weather can have a significant impact on our results of operations and are also considered in our hedging and optimization activities. Most of our power plants are located in regional power markets where the greatest demand for power occurs during the summer months, which is our fiscal third quarter. Depending on existing contract obligations and forecasted weather and power demands, we may maintain either a larger or smaller open position on fuel supply and committed generation during the summer months in order to protect and enhance our Commodity Margin accordingly.

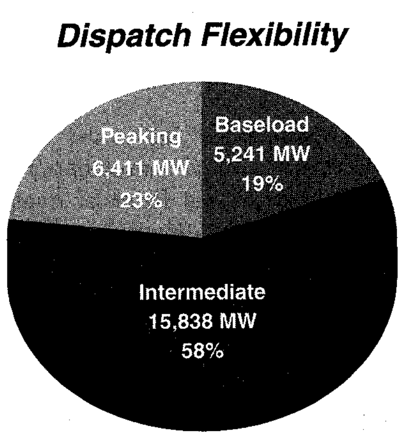
SEGMENT AND SIGNIFICANT CUSTOMER INFORMATION

See Note 16 of the Notes to Consolidated Financial Statements for a discussion of financial information by reportable segment.

DESCRIPTION OF OUR POWER PLANTS







Power Plants in Operation at December 31, 2010

We operate 91 power plants, with an aggregate operating generation capacity of approximately 27,490 MW.

Natural Gas-Fired Fleet

Our natural gas-fired power plants primarily utilize two types of design: 4,376 MW of simple-cycle combustion turbines and 22,385 MW of combined-cycle combustion turbines and a small portion from natural gas-fired steam turbines. Simple-cycle combustion turbines burn natural gas to spin a single turbine to generate power. A combined-cycle combusts as a simple-cycle and also uses the exhaust heat from the simple-cycle combustion to help create steam which can then spin a steam turbine. Simple-cycle turbines are easier to maintain, but combined-cycle turbines operate with much higher efficiency. Our "all in" Steam Adjusted Heat Rate for 2010 for the power plants we operate was 7,338 Btu/KWh which results in a power conversion efficiency of approximately 46%. The power conversion efficiency is a measure of how efficiently a fossil fuel power plant converts thermal energy to electrical energy. Our "all in" Steam Adjusted Heat Rate includes all fuel required to dispatch our power plants including "start-up" and "shut-down" fuel, as well as all non-steady state operations. Once our power plants achieve steady state operations, our combined-cycle power plants achieve an average power conversion efficiency of approximately 50%. Additionally, we also sell steam from our cogeneration power plants, which improves our power conversion efficiency in steady state operations from these power plants to an average of approximately 53%. Due to our modern combustion turbine fleet, our power conversion efficiency is significantly better than that of older technology natural gas-fired power plants and coal-fired power plants, which typically have power conversion efficiencies that range from 31% to 36%.

Each of our power plants currently in operation is capable of producing power for sale to a utility, another third-party end user or an intermediary such as a marketing company. At some of our power plants we also produce thermal energy (primarily steam and chilled water), which can be sold to industrial and governmental users.

Our natural gas fleet is relatively young with a weighted average age, based upon MW capacities in operation, of approximately eleven years. Taken as a portfolio, our natural gas power plants are among the most efficient in converting natural gas to power and emit far fewer pollutants than most typical utility fleets. The age, scale, efficiency and cleanliness of our power plants is a unique profile in the independent power sector.

The majority of the combustion turbines in our fleet are one of four technologies: GE 7FA, GE LM6000, Siemens 501FD or Siemens V84.2 turbines. We maintain our fleet through a regular and rigorous maintenance program. As units reach certain targets recommended by the original equipment manufacturer, which are typically based upon service hours or number of starts, we perform the maintenance that is required for that unit at that stage in its life cycle. Our large fleet of similar technologies has enabled us to build significant technical and engineering experience with these units. We leverage this experience by performing much of our major maintenance ourselves with our Turbine Maintenance Group subsidiary.

Geothermal Fleet

Our Geysers Assets are a 725 MW fleet of 15 operating power plants in northern California. Geothermal power is considered a renewable energy because the steam harnessed to power our turbines is produced inside the Earth and does not require burning fuel. The steam is produced below the Earth's surface from reservoirs of hot water, both naturally occurring and injected. The steam is piped directly from the underground production wells to the power plants and used to spin turbines to make power. For the past ten consecutive years, our Geysers Assets have continued to generate approximately 6 million MWh per year. Unlike other renewable resources such as wind or sunlight, which depend on intermittent sources to generate power, making them less reliable, geothermal power provides a consistent source of energy as evidenced by our Geysers Assets' availability record of over 98% in 2010.

We inject water back into the steam reservoir, which extends the useful life of the resource and helps to maintain the output of our Geysers Assets. The water we inject comes from the condensate associated with the steam extracted to generate power, wells and creeks, as well as water purchase agreements for reclaimed wastewater. We receive and inject an average of approximately 18 million gallons of reclaimed wastewater per day into the geothermal steam reservoir at The Geysers where the water is naturally heated by the Earth, creating additional steam to fuel our Geysers Assets. Approximately 14 million gallons per day is received from the Santa Rosa Geysers Recharge Project, developed by us and the City of Santa Rosa, which was previously being discharged into the Russian River and we receive, on average, approximately 4 million gallons a day from The Lake County Recharge Project from Lake County. As a result, steam flow decline rates have become very small. We expect that, as a result of the water injection program, the reservoir at our Geysers Assets will be able to supply economic quantities of steam for the foreseeable future.

We periodically obtain independent geothermal studies to help us assess the economic life of our geothermal reserves. Our most recent independent geothermal reserve study was conducted in 2006. Our evaluations of our geothermal reserves, including our review of any applicable independent studies conducted, indicate that our Geysers Assets should continue to supply sufficient steam to generate positive cash flows at least through 2050. In reaching this conclusion, our evaluation, consistent with the 2006 study, assumes that defined "proved reserves" are those quantities of geothermal energy which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations.

We lease the geothermal steam fields from which we extract steam for our Geysers Assets. We have leasehold mineral interests in 110 leases comprising approximately 29,019 acres of federal, state and private geothermal resource lands in The Geysers region of northern California. Our leases cover one contiguous area of property that comprises approximately 45 square miles in the northwest corner of Sonoma County and southeast corner of Lake County. The approximate breakout by volume of steam removed under the above leases for the year ended 2010 is:

- 29% related to leases with the federal government via the Minerals Management Service,
- 27% related to leases with the California State Lands Commission, and
- 44% related to leases with private landowners/leaseholders.

In general, our geothermal leases grant us 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 on a monthly basis from 10 to 31 days (depending upon the lease terms) following the close of the production month. Such royalties and other payments are payable to landowners, state and federal agencies and others, and vary widely as to the particular lease. In general, royalties payable are calculated based upon a percentage of total gross revenue received by us associated with our geothermal leases. Each lease's royalty calculation is based upon its percentage of revenue as calculated by its steam generated to the total steam generated by our Geysers Assets as a whole.

Our geothermal leases are generally for initial terms varying from 10 to 20 years or for so long as geothermal resources are produced and sold. A few of our geothermal leases were signed in excess of 30 years ago. Our federal leases are, in general, for an initial 10-year period with renewal clauses for an additional 40 years for a maximum of 50 years. The 50-year term expires in 2024 for the majority of our federal leases. However, our federal leases allow for a preferential right to renewal for a second 40-year term on such terms and conditions as the lessor deems appropriate if, at the end of the initial 40-year term, geothermal steam is being produced or utilized in commercial quantities. The majority of our other leases run through the economic life of our Geysers Assets and provide for renewals so long as geothermal resources are being produced or utilized, or are capable of being produced or utilized, in commercial quantities from the leased land or from land unitized with the leased land. Although we believe that we will be able to renew our leases through the economic life of our Geysers Assets on terms that are acceptable to us, it is possible that certain of our leases may not be renewed, or may be renewable only on less favorable terms.

In addition, we hold 40 geothermal leases comprising approximately 43,840 acres of federal geothermal resource lands in the Glass Mountain area in northern California, which is separate from The Geysers region. Four test production wells were drilled prior to our acquisition of these leases and we have drilled one test well since their acquisition, which produced commercial quantities of steam during flow tests. However, the properties subject to these leases have not been developed and there can be no assurance that these leases will ultimately be developed. We are currently involved in litigation concerning our Glass Mountain leases. See Note 15 of the Notes to Consolidated Financial Statements for a description of litigation relating to our Glass Mountain area leases.

Other Power Generation Technologies

Across the fleet, we also have a variety of older, less efficient technologies including approximately 868 MW of capacity from our power plants acquired in the Conectiv Acquisition which have conventional steam turbine technology. Approximately 340 MW of this capacity used coal as the primary fuel source prior to our acquisition. These power plants have flexibility as to fuel source and are also capable of burning natural gas or fuel oil to generate power. At the close of the Conectiv Acquisition, these plants ceased burning coal. Instead, we expect to generate power from these plants using natural gas or fuel oil and plan to modernize these sites in the longer term to natural gas-fired combustion turbines. We also have approximately 4 MW of capacity from solar power generation technology at our Vineland Solar Energy Center in New Jersey.

Table of Operating Power Plants and Projects Under Construction

Set forth below is certain information regarding our operating power plants and projects under construction as of December 31, 2010.

SEGMENT / Power Plant	NERC Region	U.S. State or Canadian Province	Technology	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)(1)(3)	Calpine Net Interest With Peaking (MW)(2)(3)	2010 Total MWh Generated(4)
WEST							
Geothermal							
McCabe #5 & #6	WECC	CA	Geothermal	100%	78	78	694,417
Ridge Line #7 & #8	WECC	CA	Geothermal	100%	69	69	636,489
Calistoga	WECC	CA	Geothermal	100%	66	66	538,765
Eagle Rock	WECC	CA	Geothermal	100%	66	66	476,737
Quicksilver	WECC	CA	Geothermal	100%	53	53	396,226
Cobb Creek	WECC	CA	Geothermal	100%	52	52	415,025
Lake View	WECC	CA	Geothermal	100%	52	52	418,833
Sulphur Springs	WECC	CA	Geothermal	100%	51	51	419,516
Socrates	WECC	CA	Geothermal	100%	50	50	381,773
Big Geysers	WECC	CA	Geothermal	100%	48	48	487,111
Grant	WECC	CA	Geothermal	100%	43	43	329,676
Sonoma	WECC	CA	Geothermal	100%	42	42	309,051
West Ford Flat	WECC	CA	Geothermal	100%	24	24	224,862
Aidlin	WECC	CA	Geothermal	100%	17	17	148,960
Bear Canyon	WECC	CA	Geothermal	100%	14	14	103,615
Natural Gas-Fired							
Delta Energy Center	WECC	CA	Natural Gas	100%	835	857	3,999,134
Pastoria Energy Center	WECC	CA	Natural Gas	100%	750	729	4,335,033
Hermiston Power Project	WECC	OR	Natural Gas	100%	547	616	3,241,567
Otay Mesa Energy Center	WECC	CA	Natural Gas	100%	513	608	2,163,158
Metcalf Energy Center	WECC	CA	Natural Gas	100%	564	605	2,587,531
Sutter Energy Center	WECC	CA	Natural Gas	100%	542	578	1,820,440
Los Medanos Energy Center	WECC	CA	Natural Gas	100%	506	560	3,313,399
South Point Energy Center	WECC	AZ	Natural Gas	100%	520	530	1,762,385
Los Esteros Critical Energy Facility	WECC	CA	Natural Gas	100%	—	188	39,488
Gilroy Energy Center	WECC	CA	Natural Gas	100%	—	141	31,709
Gilroy Cogeneration Plant	WECC	CA	Natural Gas	100%	117	128	160,654
King City Cogeneration Plant	WECC	CA	Natural Gas	100%	120	120	588,507
Greenleaf 1 Power Plant	WECC	CA	Natural Gas	100%	50	50	245,818
Greenleaf 2 Power Plant	WECC	CA	Natural Gas	100%	49	49	259,244
Wolfskill Energy Center	WECC	CA	Natural Gas	100%	—	48	7,634
Yuba City Energy Center	WECC	CA	Natural Gas	100%	—	47	28,129
Feather River Energy Center	WECC	CA	Natural Gas	100%	—	47	13,526
Creed Energy Center	WECC	CA	Natural Gas	100%	—	47	7,628
Lambie Energy Center	WECC	CA	Natural Gas	100%	—	47	7,423
Goose Haven Energy Center	WECC	CA	Natural Gas	100%	—	47	7,331
Riverview Energy Center	WECC	CA	Natural Gas	100%	—	47	8,126
King City Peaking Energy Center	WECC	CA	Natural Gas	100%	—	44	7,315
Agnews Power Plant	WECC	CA	Natural Gas	100%	28	28	210,226
Subtotal					5,866	6,886	30,826,461

SEGMENT / Power Plant	NERC Region	U.S. State or Canadian Province	Technology	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)(1)(3)	Calpine Net Interest With Peaking (MW)(2)(3)	2010 Total MWh Generated(4)
TEXAS							
Freestone Energy Center	TRE	TX	Natural Gas	75%	779	746	4,656,816
Deer Park Energy Center	TRE	TX	Natural Gas	100%	830	1,001	5,443,722
Baytown Energy Center	TRE	TX	Natural Gas	100%	740	800	3,957,054
Pasadena Power Plant	TRE	TX	Natural Gas	100%	763	781	2,765,711
Magic Valley Generating Station	TRE	TX	Natural Gas	100%	662	692	2,906,495
Brazos Valley Power Plant	TRE	TX	Natural Gas	100%	508	594	2,435,127
Channel Energy Center	TRE	TX	Natural Gas	100%	463	608	2,331,305
Corpus Christi Energy Center	TRE	TX	Natural Gas	100%	426	500	2,233,798
Texas City Power Plant	TRE	TX	Natural Gas	100%	400	453	1,363,585
Clear Lake Power Plant	TRE	TX	Natural Gas	100%	344	400	577,667
Hidalgo Energy Center	TRE	TX	Natural Gas	78.5%	392	374	1,498,070
Freeport Energy Center(5)	TRE	TX	Natural Gas	100%	210	236	1,505,041
Subtotal					6,517	7,185	31,674,391
NORTH							
Bethlehem Energy Center	RFC	PA	Natural Gas	100%	1,037	1,130	1,935,927
Hay Road Energy Center	RFC	DE	Natural Gas	100%	1,030	1,130	1,412,518
Edge Moor Energy Center	RFC	DE	Natural Gas/oil	100%	—	725	350,163
Riverside Energy Center	MRO	WI	Natural Gas	100%	518	603	671,767
Westbrook Energy Center	NPCC	ME	Natural Gas	100%	537	537	2,674,645
Greenfield Energy Centre(6)	NPCC	ON	Natural Gas	50%	422	519	1,228,080
RockGen Energy Center	MRO	WI	Natural Gas	100%	—	503	166,542
Zion Energy Center	RFC	IL	Natural Gas	100%	—	503	140,828
Mankato Energy Center	MRO	MN	Natural Gas	100%	280	375	514,697
Cumberland Energy Center	RFC	NJ	Natural Gas	100%	—	191	16,664
Deepwater Energy Center	RFC	NJ	Natural Gas	100%	—	158	47,596
Kennedy International Airport Power Plant	NPCC	NY	Natural Gas	100%	110	121	581,439
Sherman Avenue Energy Center	RFC	NJ	Natural Gas	100%	—	92	1,555
Bethpage Energy Center 3	NPCC	NY	Natural Gas	100%	60	80	226,033
Middle Energy Center	RFC	NJ	Oil	100%	—	77	998
Carll's Corner Energy Center	RFC	NJ	Natural Gas	100%	—	73	2,978
Cedar Energy Center	RFC	NJ	Oil	100%	—	68	2,478
Mickleton Energy Center	RFC	NJ	Natural Gas	100%	—	67	1,158
Missouri Avenue Energy Center	RFC	NJ	Oil	100%	—	60	1,997
Bethpage Power Plant	NPCC	NY	Natural Gas	100%	55	56	147,647
Christiana Energy Center	RFC	DE	Oil	100%	—	53	350
Bethpage Peaker	NPCC	NY	Natural Gas	100%	—	48	45,600
Stony Brook Power Plant	NPCC	NY	Natural Gas	100%	45	47	305,394
Tasley Energy Center	RFC	VA	Oil	100%	—	26	884
Whitby Cogeneration(7)	NPCC	ON	Natural Gas	50%	25	25	172,579
Delaware City Energy Center	RFC	DE	Oil	100%	—	23	100
West Energy Center	RFC	DE	Oil	100%	—	20	34
Bayview Energy Center	RFC	VA	Oil	100%	—	12	4,714
Crisfield Energy Center	RFC	MD	Oil	100%	—	10	237
Vineland Solar Energy Center	RFC	NJ	Solar	100%	—	4	2,791
Subtotal					4,119	7,336	10,658,393

SEGMENT / Power Plant	NERC Region	U.S. State or Canadian Province	Technology	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)[(1)(3)]	Calpine Net Interest With Peaking (MW)[(2)(3)]	2010 Total MWh Generated[(4)]
SOUTHEAST							
Broad River Energy Center	SERC	SC	Natural Gas	100%	—	847	949,183
Morgan Energy Center	SERC	AL	Natural Gas	100%	720	807	3,853,945
Decatur Energy Center	SERC	AL	Natural Gas	100%	782	795	3,449,786
Columbia Energy Center	SERC	SC	Natural Gas	100%	455	606	190,601
Carville Energy Center	SERC	LA	Natural Gas	100%	449	501	2,533,996
Santa Rosa Energy Center	SERC	FL	Natural Gas	100%	235	225	363,412
Hog Bayou Energy Center	SERC	AL	Natural Gas	100%	235	237	556,142
Pine Bluff Energy Center	SERC	AR	Natural Gas	100%	184	215	1,205,469
Oneta Energy Center	SPP	OK	Natural Gas	100%	980	1,134	2,715,849
Osprey Energy Center	FRCC	FL	Natural Gas	100%	537	599	2,155,131
Auburndale Peaking Energy Center	FRCC	FL	Natural Gas	100%	—	117	13,930
Subtotal					4,577	6,083	17,987,444
Total operating power plants (91)					**21,079**	**27,490**	**91,146,689**
Power plants sold and retired during 2010							
Rocky Mountain Energy Center	WECC	CO	Natural Gas	100%	n/a	n/a	2,686,098
Blue Spruce Energy Center	WECC	CO	Natural Gas	100%	n/a	n/a	372,881
Pittsburg Power Plant	WECC	CA	Natural Gas	100%	n/a	n/a	16,570
Watsonville (Monterey) Cogeneration Plant	WECC	CA	Natural Gas	100%	n/a	n/a	65,751
Subtotal					n/a	n/a	3,141,300
Total operating, sold and retired power plants							**94,287,989**
Projects under construction							
Russell City Energy Center[(8)]	WECC	CA	Natural Gas	75%[(8)]	429	464	n/a
Los Esteros Critical Energy Facility Expansion	WECC	CA	Natural Gas	100%	120	120	n/a
York Energy Center	RFC	PA	Natural Gas	100%	519	565	n/a
Total operating power plants and projects					**22,147**	**28,639**	

(1) Natural gas-fired fleet capacities are derived on as-built as-designed outputs, including upgrades, based on site specific annual average temperatures and average process steam flows for cogeneration power plants, as applicable. Geothermal capacities are derived from historical generation output and steam reservoir modeling under average ambient conditions (temperatures and rainfall).

(2) Natural gas-fired fleet peaking capacities are primarily derived on as-built as-designed peaking outputs based on site specific average summer temperatures and include power enhancement features such as heat recovery steam generator duct-firing, gas turbine power augmentation and/or other power augmentation features. For certain power plants with definitive contracts, capacities at contract conditions have been included. Oil-fired capacities reflect capacity test results.

(3) These outputs do not factor in the typical MW loss and recovery profiles over time, which natural gas-fired turbine power plants display associated with their planned major maintenance schedules.

(4) MWh generation is shown here as our net operating interest.

(5) Freeport Energy Center is owned by us; however, it is contracted and operated by The Dow Chemical Company.

(6) We hold a 50% partnership interest in Greenfield Energy Centre; however, it is operated by a third party, and is an unconsolidated subsidiary (see Note 5 of the Notes to Consolidated Financial Statements).

(7) We hold 50% equity interest in Whitby Cogeneration; however, it is operated by Atlantic Packaging Products Ltd., and is an unconsolidated subsidiary (see Note 5 of the Notes to Consolidated Financial Statements).

(8) Aircraft Services' interest is approximately 35% at December 31, 2010; however, their ownership interest fluctuates based on their funding of construction costs and posting of project security, and they are currently funding their construction obligations at 25%. See also discussion of our construction, upgrades and growth initiatives in "—Liquidity and Capital Resources" in Item 7. of this Report. We have presented our MW information based upon our expected 75% share.

We provide operations and maintenance services for all but three of the power plants in which we have an interest. Such services include the operation of power plants, geothermal steam fields, wells and well pumps and natural gas pipelines. We also supervise maintenance, materials purchasing and inventory control, manage cash flow, train staff and prepare operations and maintenance manuals for each power plant that we operate. As a power plant develops an operating history, we analyze its operation and may modify or upgrade equipment, or adjust operating procedures or maintenance measures to enhance the power plant's reliability or profitability.

Certain power plants 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 power (and, if applicable, thermal energy and capacity) produced by such power plants and generally provide that the obligations to pay interest and principal on the loans are secured solely by the capital stock or partnership interests, physical assets, contracts and/or cash flows attributable to the entities that own the power plants. The lenders under these project financings 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 power plants. However, defaults under some project financings may result in cross-defaults to certain of our other debt and debt instruments, including our Corporate Revolving Facility and First Lien Notes. Acceleration of the maturity of a project financing following a default may also result in a cross-acceleration of such other debt.

Substantially all of the power plants in which we have an interest are located on sites which we own or lease on a long-term basis.

EMISSIONS AND OUR ENVIRONMENTAL PROFILE

Our environmental record has been widely recognized. We are an EPA Climate Leaders Partner with a stated goal to reduce GHG emissions, we became the first power producer to earn the distinction of Climate Action Leader™, and we have certified our GHG emissions inventory with the California Climate Action Registry every year since 2003. In 2010, our emissions of GHG amounted to about 42 million tons.

Natural Gas-Fired Generation

Our natural gas-fired, primarily combined cycle fleet consumes significantly less fuel to generate power than conventional boiler/steam turbine power plants and emits fewer air pollutants per MWh of power produced as compared to coal-fired or oil-fired power plants. All of our power plants have air emissions controls and most have selective catalytic reduction to further reduce emissions of nitrogen oxides, a precursor of atmospheric ozone. In addition, we have implemented a program of proprietary operating procedures to reduce natural gas consumption and further lower air pollutant emissions per MWh of power generated. The table below summarizes approximate air pollutant emission rates from our natural gas-fired, combined cycle power plants compared to the average emission rates from U.S. coal-, oil- and natural gas-fired power plants as a group, based on the most recent statistics available to us.

	Air Pollutant Emission Rates — Pounds of Pollutant Emitted Per MWh of Power Generated		
Air Pollutants	**Average U.S. Coal-, Oil-, and Natural Gas-Fired Power Plant(1)**	**Calpine Natural Gas-Fired, Combined-Cycle Power Plant(2)**	**Compared to Average U.S. Coal-, Oil-, and Natural Gas-Fired Power Plant**
Nitrogen Oxide, NOx Acid rain, smog and fine particulate formation	1.94	0.12	93.8% less
Sulfur Dioxide, SO_2 Acid rain and fine particulate formation	4.85	0.0044	99.9% less
Mercury Compounds(3) Neurotoxin	0.000030	—	100.0% less
Carbon Dioxide, CO_2 Principal GHG—contributor to climate change	1,842	872	52.7% less

(1) The average U.S. coal-, oil- and natural gas-fired power plant's emission rates were obtained from the U.S. Department of Energy's Electric Power Annual Report for 2009. Emission rates are based on 2009 emissions and net generation. The U.S. Department of Energy has not yet released 2010 information.

(2) Our natural gas-fired, combined-cycle power plant estimated emission rates are based on our 2009 emissions and power generation data from our natural gas-fired combined-cycle power plants (excluding combined heat power plants) as measured under the EPA reporting requirements.

(3) The U.S. coal-, oil- and natural gas-fired power plant air emissions of mercury compounds were obtained from the U.S. EPA Toxics Release Inventory for 2009. Emission rates are based on 2009 emissions and net generation from U.S. Department of Energy's Electric Power Annual Report for 2009.

Geothermal Generation

Our 725 MW fleet of geothermal power plants utilizes a natural, renewable energy source, steam from the Earth's interior, to generate power. Since these power plants do not burn fossil fuel, they are able to produce power with negligible CO_2 (the principal GHG), NO_X and SO_2 emissions. Compared to the average U.S. coal-, oil- and natural gas-fired power plant, our Geysers Assets emit 99.8% less NO_X, 100% less SO_2 and 95.3% less CO_2. There are 18 active geothermal power plants located in The Geysers region of northern California. We own and operate 15 of them. We recognize the importance of our Geysers Assets and we are committed to extending and expanding this renewable geothermal resource through the addition of new steam wells and wastewater recharge projects where clean, reclaimed wastewater from local municipalities is recycled into the geothermal resource where it is converted by the Earth's heat into steam for power production.

Water Conservation and Reclamation

We have also invested substantially in technologies and systems that reduce the impact of our operations on water as a natural resource:

- We receive and inject an average of approximately 18 million gallons of reclaimed wastewater per day into the geothermal steam reservoir at The Geysers where the water is naturally heated by the Earth, creating additional steam to fuel our Geysers Assets. Approximately 14 million gallons is received from the Santa Rosa Geysers Recharge Project, developed by us and the City of Santa Rosa, which was previously being discharged into the Russian River, and we receive, on average, approximately 4 million gallons a day from The Lake County Recharge Project from Lake County.

- In our combined-cycle plants we use mechanical draft cooling towers, which consume up to 90 percent less water than conventional once-through cooling systems. Two of our combined cycle plants employ air-cooled condensers, which consume virtually no water for cooling. We use once-through cooling systems at only two power plants, our Deepwater and Edge Moor power plants, which were acquired as part of our Conectiv Acquisition.

- Through separate agreements with several municipalities where we use cooling towers, we use treated wastewater for cooling at several of our power plants. This eliminates the need to consume valuable surface and/or groundwater supplies, in the amount of three to four million gallons per day for an average power plant.

GOVERNMENTAL AND REGULATORY MATTERS

We are subject to complex and stringent energy, environmental and other laws and regulations at the federal, state and local levels as well as within the ISO markets in which we participate in connection with the development, ownership and operation of our power plants. Federal and state legislative and regulatory actions continue to change how our business is regulated.

Environmental Regulations

Congress proposed but failed to enact climate change legislation in the last session. The November 2010 election resulted in a change in control of Congress with Republicans controlling the U.S. House of Representatives. While the Senate may continue considering legislation addressing climate change, it is unlikely that such legislation will be enacted in the near term. Instead, we expect the current Administration to place more emphasis on increasing the regulations, powers and activities of the EPA under the CAA. In 2010, the EPA proposed or finalized regulations governing GHG emissions from major sources as well as emissions of criteria pollutants from the electric generation sector. The EPA is expected to propose additional regulations under the CAA addressing hazardous air pollutants. Although we cannot predict the ultimate effect of future changes that climate change legislation or regulations could have on our business, we believe we will face a lower compliance burden than some of our competitors due to the relatively low GHG emission rates of our fleet. We continue to monitor and actively participate in the initiatives where we anticipate an impact on our business. Some of the more significant governmental and regulatory matters that affect our business are discussed below.

Federal Regulation of GHG and Other Air Emissions under Existing Law

The CAA provides for the regulation of air quality and air emissions, largely through state implementation of federal requirements. We believe that all of our operating power plants comply with existing federal and state performance standards mandated under the CAA. Several CAA programs that affect our power plants and/or our competitors are discussed below.

Regulation of GHG Emissions

On April 2, 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG emissions under the CAA. As a result of this ruling, the EPA is moving forward to regulate GHG emissions pursuant to its existing authority under the CAA. On December 7, 2009, the EPA made an "endangerment finding" with respect to GHGs, determining that current and projected concentrations of six key GHGs endanger the public health and welfare of current and future generations. As part of the EPA's initiative to regulate GHGs, on May 13, 2010, the EPA finalized regulations referred to as the "Tailoring Rule" to require sources emitting over 100,000 tons per year of GHG emissions to undergo a major new source review ("NSR") when such sources make modifications that would increase their GHG emissions by greater than 75,000 tons per year. Beginning January 2011, such modifications, or new construction, would be subject to the EPA's prevention of significant deterioration ("PSD") rules and subject to best available control technology ("BACT") for GHG, as well as public review and notice provided they trigger a major NSR for another criteria pollutant. Beginning in July 2011, sources exceeding the GHG PSD thresholds will be subject to major NSR, regardless of whether they trigger PSD review for other criteria pollutants. The EPA has issued guidance to permitting authorities on the implementation of GHG BACT that focuses on energy efficiency measures but considers carbon capture and storage "technically feasible" and therefore it must be considered in the BACT analysis. We believe that the impact of the final Tailoring Rule will be neutral to us because we expect that our efficient power plants already achieve BACT for GHGs.

Regulation of Criteria Pollutants

The CAA requires the EPA to regulate emissions of pollutants considered harmful to public health and the environment. The EPA has set NAAQS for six principal pollutants: carbon monoxide, lead, NO_2, particulate matter ("PM"), ozone and SO_2. These pollutants are called "criteria pollutants."

CAIR and Multi-Pollutant Programs — Pursuant to authority granted under the CAA, the EPA promulgated the Clean Air Interstate Rule, or CAIR, regulations in March 2005, applicable to 28 eastern states and the District of Columbia, to facilitate attainment of its ozone and fine particulates NAAQS issued in 1997. When fully implemented, CAIR's goal is to reduce SO_2 emissions in these states by over 70%, and NO_X emissions by over 60% from 2003 levels by 2015. CAIR establishes annual cap-and-trade programs for SO_2 and NO_X as well as a seasonal program for NO_X. On July 11, 2008, a panel of the U.S. Court of Appeals for the D.C. Circuit invalidated CAIR, stating that the "EPA's approach – region-wide caps with no state specific quantitative contribution determinations or emission requirements – is fundamentally flawed." The court did not overturn the existing cap-and-trade program for SO_2 reductions under the Acid Rain Program or the existing ozone season cap-and-trade program under the NO_X State Implementation Plan Call. On September 25, 2008, the EPA petitioned the court for rehearing. On December 23, 2008, the court remanded CAIR without vacatur for the EPA to conduct further proceedings consistent with the July 11, 2008 opinion. As a result of the court's decision, CAIR was left intact and went into effect as planned on January 1, 2009, for many of our power plants located throughout the eastern and central U.S. Due to favorable allowance allocations, particularly in Texas, we have a net surplus of annual NO_X allowances and the net financial impact of the program to our operations is positive.

On July 6, 2010, the EPA proposed the Transport Rule, which would require 31 states and the District of Columbia to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states. If the proposed Transport Rule becomes final, beginning in 2012, emission reductions will be governed by this rule, instead of CAIR. The EPA estimates this rule, along with concurrent state and EPA actions, will reduce power plant SO_2 emissions by 71% and NO_X emissions by 52% over 2005 levels by year 2014. The Transport Rule establishes state specific emissions budgets and allows intrastate trading and limited interstate trading. All allowances will be distributed to existing and new sources with separate programs for annual emissions and ozone season emissions. Allowance budgets will be allocated to states for disbursement and states may choose to allocate directly or defer to the EPA. The EPA's proposed unit allocations will be based on historic emissions, an approach that we oppose. We reviewed the proposed rules and submitted comments to the EPA. On January 7, 2011, the EPA published a Notice of Data Availability ("NODA") associated with providing data on potential allocation mechanisms. NODA addresses several concerns that we raised in our comment letter, including allocating allowances according to historic heat input as opposed to historic emissions. We submitted comments to the EPA in general support of proposals in the NODA, particularly as those proposals pertain to allowance allocation.

Section 185 Fees — Section 185 of the CAA requires major stationary sources of NO_X and volatile organic compounds ("VOCs"), such as power plants and refineries, in areas that fail to attain the NAAQS for ozone by the attainment date to pay a fee to the state or in the absence of state action, the EPA. The fee was set by Congress in the CAA at \$5,000 per ton of NO_X or VOC (adjusted for inflation or approximately \$8,950 per ton in 2010) and is payable on emissions that exceed 80% of each individual power plant's baseline emissions, which were established in the year before the attainment date; however, the EPA is considering alternative baseline calculations. The fee will remain in effect until the designated area achieves attainment. We operate 14 power plants that are located within designated nonattainment areas in Texas, New York, New Jersey and Louisiana, which are subject to this fee. On January 5, 2010, the EPA issued guidance on developing fee programs required under Section 185 of the CAA. Texas issued a draft rulemaking to collect the fees in late 2009; however, Texas inactivated the proposed rulemaking in 2010. We estimate that compliance with this fee could result in additional costs of approximately \$3 million to \$5 million on an annual basis and our financial statements include accruals for our estimated Section 185 fees. Our estimate is dependent upon a number of factors that could change in the future dependent upon, among other things: implementation by the states of guidance from the EPA, state rulemakings, the designation of nonattainment status, our number of power plants located in these areas and our level of NO_X emissions.

Acid Rain Program — As a result of the 1990 CAA amendments, the EPA established a cap-and-trade program for SO_2 emissions from power plants throughout the U.S. Starting with Phase II of the program in 2000, a permanent ceiling (or cap) was set at 10 million tons per year, declining to 8.95 million tons per year by 2010. The EPA allocated SO_2 allowances to power plants. Each allowance permits a unit to emit one ton of SO_2 during or after a specified year, and allowances may be bought, sold or banked. All but a small percentage of allowances were allocated to power plants placed into service before 1990. Our Edge Moor and Deepwater power plants currently receive sufficient free SO_2 allowances; therefore, we will have no compliance expense for this program.

Regulation of Hazardous Air Pollutants

The CAA regulates a large number of air pollutants that are known to cause or may reasonably be anticipated to cause adverse effects to human health or adverse environmental effects, known as hazardous air pollutants ("HAPs"). The EPA is required to issue technology-based national emissions standards for hazardous air pollutants ("NESHAPs") to limit the release of specified HAPs from specific industrial sectors.

On October 22, 2009, the EPA signed a consent decree that was lodged in the U.S. District Court for the District of Columbia by the EPA in settlement of a suit brought by several environmental groups alleging that the EPA failed to promulgate final emissions standards based on maximum achievable control technology for hazardous air pollutants from coal- and oil-fired power plants, pursuant to Section 112(d) of the CAA, by the statutorily-mandated deadline. The consent decree requires the EPA to promulgate final HAP emission standards by November 2011 that will likely require Hg and acid gas control retrofits on marginal coal-fired power plants to be operational by as early as 2014. As a fleet, we emit little Hg and negligible amounts of acid gases and do not expect to experience significant operating costs or retrofit obligations from the new standards. Should coal-fired power plants in our regional markets be forced to retrofit or retire, the new standards could benefit our competitive position.

Court Rulings

In the absence of federal climate change legislation, litigation raising claims relating to GHG emissions is working its way through the federal courts. Recent federal court decisions are divided as to whether large emitters of GHGs may be sued under common law theories of nuisance and negligence.

On September 21, 2009, the Second Circuit issued a ruling in *State of Connecticut, et al. v. American Electric Power Company Inc., et al.*, reversing a lower court's dismissal of two public nuisance claims filed by various states, municipalities and private entities against operators of coal-fired power plants. Plaintiffs argued that the power plant defendants contribute to global warming by emitting 650 million tons per year of CO_2 and these emissions are causing and will continue to cause serious harms affecting human health and natural resources. The lower court held that plaintiffs' claims presented a non-legal political question and dismissed the complaints. The Second Circuit vacated the lower court's ruling, ruling that the case did not present non-justiciable political questions, the plaintiffs stated claims under federal common law of nuisance, and the plaintiffs had standing. On December 6, 2010, the U.S. Supreme Court granted certiorari in the defendants' appeal of the Second Circuit's decision, with oral argument expected in March or April 2011. The Supreme Court's decision is expected to have consequences for other climate change cases that are in the Fourth, Fifth, and Ninth Circuit courts of appeal, including *Native Village of Kivalina v. ExxonMobil.* In *Kivalina*, a federal district court in California sided with the defendants, 24 oil, energy and utility companies, against the Village of Kivalina, a small, self-governing tribe of Inupiat people who reside north of the Arctic Circle. The residents of Kivalina had sued the defendants for damages under federal nuisance law arguing that, as a result of global warming, Kivalina is subject to coastal storm waves and surges. On September 30, 2009, the court ruled in favor of the defendants finding that the plaintiff's global warming claim was based upon the emission of GHGs from innumerable sources located throughout the world affecting the entire planet and its atmosphere and that no federal standards limit the discharge of GHGs. *Kivalina* is currently on appeal to the Ninth Circuit court.

We cannot predict the outcome of these cases or what impact the precedent of these cases could have on our business.

Regional and State Air Emission Activities

Several states and regional organizations are developing, or already have developed, state-specific or regional initiatives to reduce GHG emissions through mandatory programs. The most advanced programs include the RGGI in the northeast states and California's implementation of its own GHG policy pursuant to AB 32, including its RPS. The evolution of these programs could have a material impact on our business.

RGGI

On January 1, 2009, ten northeast and Mid-Atlantic states implemented a cap-and-trade program, RGGI, that affects our power plants in Maine, New York, New Jersey and Delaware (together emitting about 3.9 million tons of CO_2 annually). RGGI caps regional CO_2 emissions and requires generators to acquire one allowance for every ton of CO_2 emitted over a three-year compliance period. Apart from state-specific set-asides and other factors, the vast majority of the region's CO_2 allowances are distributed to the market via public auction. RGGI auctions have recently cleared at the program's floor price of $1.86 per ton. We are required to purchase allowances by buying them in RGGI public auctions or via the secondary market, or by investment in qualified offsets, to cover CO_2 emissions from our power plants in the RGGI region. We have also received annual allocations from New York's long-term contract set-aside pool to cover some of the CO_2 emissions attributable to our PPAs at both the Kennedy International Airport Power Plant and Stony Brook Power Plant, and we received allowances from our Conectiv Acquisition that were granted to our power plants in Delaware pursuant to the state's allowance allocation program. We do not anticipate any significant business impact from RGGI, given the efficiency of our power plants in RGGI states.

California

AB 32 and Senate Bill 1368 were signed into law in September 2006. AB 32 creates a statewide cap on GHG emissions and requires the state to return to 1990 emission levels by 2020. As part of AB 32 implementation, California's cap-and-trade program is slated to begin in 2012. Other GHG regulatory policies promulgated under AB 32 are ongoing. On December 16, 2010, CARB approved a cap and trade regulation and identified additional modifications that need to be made by October 28, 2011, prior to the January 1, 2012 implementation date. We are actively participating in the development of these regulations. CARB has recommended that allowances be auctioned and/or allocated to affected industries. Electric generators, with some possible minor exceptions, will acquire allowances through auction. Because some of our long-term contracts may not allow for GHG cost recovery, we proposed that CARB provide direct allocation to long-term contract generators. As a result, the CARB Board directed staff via resolution to "work with interested stakeholders to ensure proper treatment under the regulation of any electricity generators or combined heat and power facilities with pre-AB 32 long-term contracts that do not allow for pass-through of costs associated with greenhouse gas emissions." We continue to work with CARB to address this issue. On January 24, 2011, a San Francisco Superior Court judge issued a Tentative Statement of Decision requiring CARB to suspend implementation of its scoping plan as required by AB 32 until the state complies with portions of the California Environmental Quality Act. CARB submitted a response to the judge's tentative decision on February 8, 2011. We expect the judge to issue a final decision by March 15, 2011. We do not expect that the decision will override the implementation of AB32, but if the decision remains unchanged, it is unclear whether it would delay the implementation of AB32.

Texas

Pursuant to authority granted under the CAA, regulations adopted by the Texas Commission on Environmental Quality ("TCEQ") to attain the one-hour and eight-hour NAAQS for ozone included the establishment of a cap-and-trade program for NO_X emitted by power generating facilities in the Houston/ Galveston ozone nonattainment area. We own and operate seven power plants that participate in this program, all of which received free NO_X allowances based on historical operating profiles. At this time, our Houston-area power plants have sufficient NO_X allowances to meet forecasted obligations under the program. However, the EPA revised the eight-hour NAAQS for ozone in 2008 from 0.080 parts per million (ppm) downward to 0.075 ppm. The EPA subsequently announced on September 16, 2009, that the protectiveness of this standard would be reconsidered and a new standard was proposed on January 19, 2010. The EPA intends to issue a final decision by July 29, 2011. The revised standard could lead to the implementation of control measures as early as 2014 for existing and newly designated areas. The dynamic nature of the ozone standard creates further uncertainty in the timing and nature of future controls, but should allowance shortfalls occur, we would be required to purchase NO_X allowances or install emissions control equipment on certain of our power plants in Texas. We are unable to predict at this time whether the new standard will result in any allowance shortfalls and, if such allowance shortfalls do occur, their impact on our business.

New Jersey

New Jersey has enacted air regulations that will require future investment in controls to enable continued operation of certain of the generation assets we acquired in the Conectiv Acquisition which may result in additional control costs to us. Our 158 MW Deepwater power plant and certain of the New Jersey peaker power plants will need additional NO_X controls to continue operating beyond 2015 under the regulations. The NJDEP is considering extending the compliance deadline for these power plants to 2017; however, a rule proposal has not yet been issued. The costs of such future controls is uncertain at this time, but not expected to adversely impact our future financial position or results of operations.

Prior to our acquisition, Conectiv was a party to certain pending penalty proceedings in the administrative courts of the State of New Jersey involving one of the older peaker power plants (Deepwater Unit 1). The NJDEP alleged that Deepwater Unit 1 had exceeded its permissible maximum heat input limit, which restricts the amount of fuel burned. Heat input limits are imposed on power plants without emissions monitoring equipment to limit emissions of pollutants that are not subject to measurement by continuous emissions monitoring systems. Appeals were filed in 2007, and a status hearing was held in January 2011. The appeals assert that the NJDEP does not have the authority to limit heat input in Title V air permits. We plan to continue to work with the NJDEP to ensure that our New Jersey assets may operate at full load. Currently, these restrictions require our Deepwater Unit 1 to operate at approximately 8 MW less than its full capacity of 86 MW. We are preparing an application to modify the Deepwater Unit 1 air permit to reclaim the 8 MW limitation, but there can be no assurance that our application will be successful. We are also preparing applications to modify the heat input limits of our peaking combustion turbines and plan to submit those applications in the first quarter of 2011.

Other

Our other power plants may also become subject to state or regional CO_2 compliance requirements. The Western Climate Initiative, launched in February 2007, is a collaboration of seven U.S. Governors and four Canadian Premiers to reduce GHG emissions and could affect our power plants in California, Arizona, Oregon and Ontario. The Western Climate Initiative's goal is to establish a multi-sector cap-and-trade program effective for most sectors of the economy by 2012 and regulation of the transportation sector by 2015. Some partner states, such as Arizona, have indicated their participation will be delayed or dependent on further economic analysis and recovery. To date, California is the only state that has reaffirmed its commitment to its participation and a 2012 start. In the Midwest, our power plants in Illinois, Wisconsin and Minnesota may become subject to CO_2 compliance requirements depending on the ultimate outcome of the Midwestern Greenhouse Gas Reduction Accord. This regional planning effort is not expected to lead to binding regulations; however, compliance requirements will be subject to prospective individual regulatory and/or legislative action by the participating states.

Renewable Portfolio Standards

Policymakers have been considering variations of a RPS at the federal and state level. Generally, a RPS requires each retail seller of electricity to include in its resource portfolio (the resources procured by the retail seller to supply its retail customers) a certain amount of power generated from renewable or clean energy resources by a certain date. Although there is currently no national RPS, President Obama has stated his goal is to have 80% of the nation's electricity provided from clean energy resources by 2035, and some U.S. Congressional leaders have continued to press for a national renewable or clean energy standard in this Congress. It is too early to determine whether or not the enactment of a national RPS will have a positive or negative impact on us. Depending on the RPS structure, an RPS could enhance the value of our existing Geysers Assets. However, an RPS would likely initially drive up the number of wind and solar resources, which could negatively impact the dispatch of our natural gas assets, primarily in Texas and California. Conversely, our natural gas power plants could benefit by providing complementary/back-up service for these intermittent renewable resources or by being included in a clean energy standard.

California is currently considering a range of options for a new and higher RPS. California's existing RPS requires certain retail power providers to generate or procure 20% of the power they sell to retail customers from renewable resources by 2010. At the end of the 2009 California legislative session, the California state legislature passed a bill to increase the state's RPS to 33% by 2020. The governor of California vetoed the bill, but, in a separate move, the governor signed an executive order directing CARB under its authority granted by AB 32 to adopt regulations consistent with a 33% RPS by 2020. CARB released the initial draft regulation creating its Renewable Electricity Standard ("RES") in 2010, a program intended to run alongside the CPUC's RPS. At present, there is no timeline identified for CARB's ultimate approval and implementation of the higher renewable electricity standard. Additionally, legislation that increases the RPS/RES to 33% will be considered in the 2010-2011 California legislative session and, if adopted, would supersede the CARB RES.

The adoption of a higher renewable standard has been slowed by controversy over the use of tradable renewable energy credits ("TRECs") for compliance with the standard. TRECs are claims to the renewable aspect of the energy that is produced by a renewable resource and can potentially be traded separately from the underlying energy. CARB's current proposed regulation for the 33% RES allows for more flexible compliance mechanisms than the current CPUC 20% RPS or the most recent draft of the RPS legislation. The 33% CARB RES proposal would allow for the unlimited use of unbundled TRECs for compliance. On January 13, 2011, the CPUC approved a decision authorizing the use of TRECs for compliance with its 20% RPS, but with significant restrictions. In particular, the decision limits the use of TRECs to 25% of a load serving entity's compliance obligation. The decision also reclassifies many existing contracts for renewable energy from out-of-state resources as "unbundled" and hence counting against the TREC cap.

A number of additional states have a RPS in place. These include Maine, Minnesota, New York, Texas and Wisconsin. Individual programs vary widely. Maine has more stringent RPS, requiring retail providers to supply no less than 30% of their needs with qualified renewable resources, according to published percentage renewable energy targets. Other states, such as Texas, have a capacity-based standard that requires a specific amount of new renewable generation to be installed by certain dates. Existing state-specific RPS requirements may change due to regulatory and/or legislative initiatives, and other states may consider implementing enforceable RPS in the future.

Other Environmental Regulations

In addition to air emissions, our power plants and the equipment necessary to support them are subject to other 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 the use of water, but can also include wetlands preservation, endangered species, hazardous materials handling and disposal, waste disposal and noise regulations. Noncompliance with environmental laws and regulations can result in the imposition of civil or criminal fines or penalties. In some instances, environmental laws may also 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 that apply to us. In most cases, analogous state laws also exist that may impose similar and, in some cases, more stringent requirements on us than those discussed below. Our general policy with respect to these laws attempts to take advantage of our relatively clean portfolio of power plants as compared to our competitors.

Clean Water Act

The federal Clean Water Act establishes rules regulating the discharge of pollutants into waters of the U.S. We are required to obtain wastewater and storm water discharge permits for wastewater and runoff, respectively, for certain of our power plants. We are required to maintain a spill prevention control and countermeasure plan with respect to certain of our natural gas power plants. We believe that we are in material compliance with applicable discharge requirements of the federal Clean Water Act.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The EPA is currently revising regulations implementing 316(b) in response to a decision issued by the U.S. Court of Appeals for the Second Circuit, *Riverkeeper, Inc. v. EPA, 475 F.3d* 83. The EPA is expected to propose rules in 2011 that could require power plants employing once-through cooling, particularly along biologically productive estuaries and rivers, to undertake major modifications to their cooling water intake structures or even install cooling towers to reduce impingement (where fish and other aquatic life get trapped against the intake screens) and entrainment (where small aquatic life passes through the intake screens and goes through the condenser at high temperatures). These rules will disproportionately affect our competitors since we have only two peaking power plants that employ once-through cooling, and we do not expect these rules to have a material impact on our operations.

Safe Drinking Water Act

Part C of the Safe Drinking Water Act establishes the underground injection control program that regulates the disposal of wastes by means of deep well injection. Although geothermal production wells, which are wells that bring steam to the surface, are exempt under the Energy Policy Act of 2005 ("EPAct 2005"), we use geothermal re-injection wells to inject reclaimed wastewater back into the steam reservoir, which are subject to this regulation. We believe that we are in material compliance with Part C of this Act.

Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act ("RCRA"), regulates the management of solid and hazardous waste. With respect to our solid waste disposal practices at our power plants and steam fields located in The Geysers region of northern California, we are also subject to certain solid waste requirements under applicable California laws. We believe that our operations are in material compliance with RCRA and all such laws.

On June 21, 2010 the EPA proposed rules to regulate coal combustion residuals ("CCRs") under RCRA. The EPA seeks to establish more stringent dam safety requirements to enhance performance of CCRs managed in surface impoundments. The EPA also seeks to regulate disposal of CCRs and has proposed to either regulate them as hazardous waste under Subtitle C of RCRA, or as nonhazardous waste under Subtitle D of RCRA. Both options will impose additional waste management costs on our competitors who rely on coal as a fuel. The EPA estimates a net present value cost of $3 to $21 billion to coal plants. We do not use coal so these rules will have no direct impact on us.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also referred to as the Superfund, requires cleanup of sites from which there has been a release or threatened release of hazardous substances, and authorizes the EPA to take any necessary response action at Superfund sites, including ordering potentially responsible parties liable for the release to pay for such actions. Potentially responsible parties 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 filing of this Report, we are not subject to any material 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 a liability under CERCLA in the future.

New Jersey Environmental Programs

New Jersey has a program mandating the cleanup of sites where there has been a release of a hazardous substance. As part of the Conectiv Acquisition on July 1, 2010, we assumed environmental remediation liabilities related to certain of the assets located in New Jersey that are subject to the Industrial Site Recovery Act ("ISRA"). Pursuant to the Conectiv Purchase Agreement, PHI is responsible for any amounts that exceed $10 million. See Note 3 of the Notes to Consolidated Financial Statements for disclosures related to our Conectiv Acquisition for our estimated exposure. We have engaged a licensed site remediation professional who has evaluated the recognized environmental conditions and is conducting site investigations in accordance with ISRA requirements as a precursor to developing the ultimate cleanup plan.

Federal Regulation of Power

FERC Jurisdiction

Electric utilities have been highly regulated by the federal government since the 1930s, principally under the Federal Power Act ("FPA"), and the U.S. Public Utility Holding Company Act of 1935. These statutes have been amended and supplemented by subsequent legislation, including PURPA and EPAct 2005. These particular statutes and regulations are discussed in more detail below.

The FPA grants the federal government broad authority over electric utilities and independent power producers, and vests its authority in FERC. Unless otherwise exempt, any person that owns or operates facilities used for the wholesale sale or transmission of power in interstate commerce is a public utility subject to FERC's jurisdiction. FERC governs, among other things, the disposition of certain utility property, the issuance of securities by public utilities, the rates, the terms and conditions for the transmission or wholesale sale of power in interstate commerce, the interlocking directorates, and the uniform system of accounts and reporting requirements for public utilities.

The majority of our power plants are subject to FERC's jurisdiction; however, certain power plants qualify for available exemptions. FERC's jurisdiction over EWGs under the FPA applies to the majority of our power plants because they are EWGs or are owned by EWGs, except our EWGs located in ERCOT. Power plants located in ERCOT are exempt from many FERC regulations under the FPA. Many of our power plants that are not EWGs are operated as QFs under PURPA. Several of our affiliates have been granted authority to engage in sales at market-based rates and blanket authority to issue securities, and have also been granted certain waivers of FERC reporting and accounting regulations available to non-traditional public utilities; however, we cannot assure that such authorities or waivers will not be revoked for these affiliates or will be granted in the future to other affiliates.

FERC has the right to review books and records of "holding companies," as defined in PUHCA 2005, that are determined by FERC to be relevant to the companies' respective FERC-jurisdictional rates. We are considered a holding company, as defined in PUHCA 2005, by virtue of our control of the outstanding voting securities of our subsidiaries that own or operate power plants used for the generation of power for sale, or that are themselves holding companies. However, we are exempt from FERC's inspection rights pursuant to one of the limited exemptions under PUHCA 2005 as we are a holding company due solely to our owning one or more QFs, EWGs and Foreign Utility Companies ("FUCOs"). If any of our entities were not a QF, EWG or FUCO, then we and our holding company subsidiaries would be subject to the books and records access requirement.

FERC's policies and rules will continue to evolve, and FERC may amend or revise them, or may introduce new policies or rules in the future. The impact of such policies and rules on our business is uncertain and cannot be predicted at this time.

FERC Regulation of Market-Based Rates

Under the FPA and FERC's regulations, the wholesale sale of power at market-based or cost-based rates requires that the seller have authorization issued by FERC to sell power at wholesale pursuant to a FERC-accepted rate schedule. FERC grants market-based rate authorization based on several criteria, including a showing that the seller and its affiliates lack market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry and that there is no opportunity for abusive transactions involving regulated affiliates of the seller. All of our affiliates that own domestic power plants, except for certain of those power plants that are QFs under PURPA or that are located in ERCOT, as well as our market-based rate companies, are currently authorized by FERC to make wholesale sales of power at market-based rates. We have voluntarily agreed to accept FERC's default, cost-based mitigation for new sales in a small balancing authority area ("BAA") referred to as Western Area Power Administration — Lower Colorado which impacts our South Point power plant. FERC believes that our South Point power plant may have market power in this one BAA; however, we expect this mitigation to have minimal impact on our business.

Market-based rate authorization could possibly be revoked for any of our market-based rate companies if they fail to continue to satisfy FERC's current or future criteria, or if FERC eliminates or restricts the ability of wholesale sellers of power to make sales at market-based rates. If market-based rate authority were revoked or restricted, affected power plants could be required to make wholesale sales of power based on cost-of-service rates, which could negatively impact their revenues.

FERC's regulations specifically prohibit the manipulation of the power markets by making it unlawful for any entity in connection with the purchase or sale of power, or the purchase or sale of power transmission service under FERC's jurisdiction, to engage in fraudulent or deceptive practices.

To ward against market manipulation, FERC requires us and other sellers making sales pursuant to their market-based rate authority to file certain reports, including quarterly reports of contract and transaction data, notices of any change in status and triennial updated market power analyses. If a seller does not timely file these reports or notices, FERC can revoke the seller's market-based rate authority. FERC's regulations also contain four market behavior rules that apply to sellers with market-based rate authority. These rules address such matters as compliance with organized Regional Transmission Organization ("RTO") or ISO market rules, communication of accurate information, price reporting to publishers of power or natural gas price indices, and record retention. Failure to comply with these regulations can lead to sanctions by FERC, including penalties and suspension or revocation of market-based rate authority.

FERC Regulation of Transfers of Jurisdictional Facilities

Dispositions of our jurisdictional facilities or certain types of financing arrangements may require prior FERC approval, which could result in revised terms or impose additional costs, or cause a transaction to be delayed or terminated. Pursuant to Section 203 of the FPA, as amended by EPAct 2005, a public utility must obtain authorization from FERC before the public utility is permitted to: sell, lease or dispose of FERC-jurisdictional facilities with a value in excess of $10 million; merge or consolidate facilities with those of another entity; or acquire any security or securities with a value in excess of $10 million issued by another public utility. FERC's prior approval is also required for transactions involving certain transfers of existing generation facilities and certain holding companies' acquisitions of facilities with a value in excess of $10 million. FERC's regulations implementing Section 203 of the FPA provide blanket authorizations for certain types of transactions, including acquisitions by holding companies that are holding companies solely due to their ownership, directly or indirectly, of one or more QFs, EWGs and FUCOs, to acquire additional QFs, EWGs or FUCOs, or the securities of additional QFs, EWGs and FUCOs without prior FERC approval.

FERC Regulation of Qualifying Facilities

Cogeneration and certain small power production facilities are eligible to be QFs under PURPA, provided that they meet certain power and thermal energy production requirements, and efficiency standards. QF status provides an exemption from PUHCA 2005 and grants certain other benefits to the QF, including, in some cases, the right to sell power to utilities at the utilities' avoided cost ("PURPA put"). Certain types of sales by QFs are also exempt from FERC regulation of wholesale sales of the QFs' power output. QFs are also exempt from most state laws and regulations. To be a QF, a cogeneration power plant must produce power and useful thermal energy for an industrial or commercial process, or heating or cooling applications in certain proportions to the power plant's total energy output, and must meet certain efficiency standards.

An electric utility may be relieved of the mandatory purchase obligation under the PURPA put if FERC determines that such QFs have access to a competitive wholesale power market.

Station Power Ruling

On August 30, 2010, FERC issued an order on remand ("remand order") regarding its station power policies in response to a ruling by the U.S. Court of Appeals for the D.C. Circuit ("D.C. Circuit"). The D.C. Circuit's ruling vacated and remanded FERC's prior orders on CAISO's station power procedures, finding that FERC had not adequately justified its decision that no retail sale occurs when a generator self-supplies station power over a monthly netting period. In its remand order, FERC reversed its prior orders relating to a generator's self-supply of station power in the markets administered by CAISO, concluding that FERC's jurisdiction covers only the transmission of station power and the states have exclusive jurisdiction to determine when the use of station power results in a retail sale. The remand order will likely impact FERC's station power policies in all of the organized markets throughout the nation. Several parties have sought rehearing of FERC's decision. If left unchanged, FERC's remand order could result in our generation facilities paying more for station power, but we cannot calculate at this time the impact the order could have on our fleet.

FERC Enforcement Authority

FERC has civil penalty authority over violations of any provision of Part II of the FPA, as well as any rule or order issued thereunder. FERC is authorized to assess a maximum civil penalty of $1 million per violation for each day that the violation continues. The FPA also provides for the assessment of criminal fines and imprisonment for violations under Part II of the FPA. This penalty authority was enhanced in EPAct 2005. With this expanded enforcement authority, violations of the FPA and FERC's regulations could potentially have more serious consequences than in the past.

NERC Compliance Requirements

Pursuant to EPAct 2005, NERC has been certified by FERC as the Electric Reliability Organization to develop and oversee the enforcement of electric system reliability standards applicable throughout the U.S., which are subject to FERC review and approval. FERC approved reliability standards may be enforced by FERC independently, or, alternatively, by the Electric Reliability Organization and regional reliability organizations with frontline responsibility for auditing, investigating and otherwise ensuring compliance with reliability standards, subject to FERC oversight. Monetary penalties of up to $1 million per day per violation may be assessed for violations of the reliability standards. Certain electric reliability standards which apply to us as a generator owner, generator operator or marketer of power (purchasing and selling entity) are effective and mandatory. In addition, the regional reliability organizations have the ability to formulate supplemental reliability standards to apply in their specific regions, which may be more stringent than the NERC reliability standards. We comply with different reliability standards, requirements and procedural rules in each region in which we operate. It is expected that additional or modified NERC and regional reliability standards will be approved by FERC in the coming years, requiring us to take additional steps to remain fully compliant.

Regional and State Regulation of Power

The following summaries of the regional rules and regulations affecting our business focus on the West, Texas and North because these are the regions in which we have the most significant portfolios of power plants. While we provide a brief overview of the primary regional rules and regulations affecting our power plants located in other regions of the country, we do not provide an in-depth discussion of these rules and regulations because our asset portfolio in those regions is not as significant. All power plant and MW data is reported as of December 31, 2010.

West

We have 23 natural gas-fired power plants, excluding one under construction, with the capacity to generate a total of 6,161 MW in the WECC NERC region, which extends from the Rocky Mountains westward. In addition, we own and operate 15 geothermal power plants located in northern California capable of producing a total of 725 MW. The majority of these power plants are located in California, in the CAISO region; however, we also own power plants in Arizona and Oregon.

CAISO is responsible for ensuring the safe and reliable operation of the transmission grid within California and providing open, nondiscriminatory transmission services. Pursuant to a FERC-approved tariff, CAISO has certain abilities to impose penalties on market participants for violations of its rules. CAISO maintains various markets for wholesale sales of power, differentiated by time and type of electrical service, into which our subsidiaries may sell power from time to time. These markets are subject to various controls, such as price caps and mitigation of bids when reference prices are exceeded. The controls and the markets themselves are subject to regulatory change at any time. CAISO runs integrated day-ahead and real-time markets for energy and ancillary services. The energy markets include centralized, day-ahead and real-time markets for energy, a nodal transmission congestion management model that results in locational marginal pricing at each generation location, financial congestion hedging instruments, a centralized day-ahead commitment process and bid caps of $750 per MWh. The bid cap is scheduled to increase to $1,000 per MWh on April 1, 2011. The locational marginal pricing market design is intended to reward and encourage generation resources on favorable grid locations, such as some of the locations of our power plants.

In California where we have several QF facilities, a recently approved CPUC settlement has the potential to change significant aspects of policy towards California QFs, including our QF facilities. Most existing California QFs are under long-term contracts. Energy pricing under many of these contracts is intended to become "market based" once functioning wholesale markets exist. The California Investor Owned Utilities ("IOUs") have argued that the launch of CAISO's MRTU satisfies the conditions necessary to end their mandatory purchase obligation under PURPA and that prices from the MRTU markets should provide the basis for energy pricing under existing QF contracts. Moreover, independent of issues related to existing QFs, CARB's Scoping Plan to implement AB 32 includes mandates for LSEs to procure existing and new efficient CHP. Stakeholders, including Calpine and other QF generators, the CPUC, and the California IOUs, engaged in lengthy settlement negotiations to resolve issues related to the PURPA put, energy pricing for generators under existing QF contracts and prospective CHP procurement mandates. A settlement was reached by most major parties and approved by the CPUC on December 16, 2010. The settlement establishes new energy pricing options for QFs under long-term contracts, including the option to shed QF host and efficiency obligations and become dispatchable, and specifies mechanisms for the California IOUs to procure both existing CHP that is not otherwise under contract and new CHP. The settlement is likely to be appealed and will not go into effect until the appeals have run their course. In addition, the settlement stipulates that it will not go into effect until FERC approves a filing by the California IOUs to end the PURPA put.

Our power plants located outside of California either sell power into the markets administered by CAISO or sell power through bilateral transactions outside CAISO. Those transactions occurring outside CAISO are subject to FERC regulation and oversight, but they are not subject to CAISO rules and regulations.

Texas

We have 12 natural gas-fired power plants in the TRE NERC region with the capacity to generate a total of 7,185 MW, all of which are physically located in the ERCOT market. ERCOT is the ISO that manages approximately 85% of Texas' load and an electric grid covering about 75% of the state, overseeing transactions associated with Texas' competitive wholesale and retail power markets. FERC does not regulate wholesale sales of power in ERCOT. The PUCT exercises regulatory jurisdiction over the rates and services of any electric utility conducting business within Texas. Our subsidiaries that own power plants in Texas have power generation company status at the PUCT, and are either EWGs or QFs and are exempt from PUCT rate regulation. ERCOT is largely a bilateral wholesale power market, which allows buyers and sellers to competitively negotiate contracts for energy, capacity and ancillary services. ERCOT implemented a nodal market system on December 1, 2010 to manage its transmission congestion and pricing. It managed transmission congestion with zonal and intra-zonal type methods prior to December 2010. ERCOT ensures resource adequacy through an energy-only model rather than the capacity-based resource adequacy model that is more common among RTOs or ISOs in the Eastern Interconnect. In ERCOT, there is a market price cap for energy and capacity purchased by ERCOT. Under certain market conditions, the offer cap could be lower. Our subsidiaries are subject to the offer cap rules, but only for sales of power and capacity services to ERCOT.

ERCOT implemented its nodal market structure on December 1, 2010. A nodal market structure results in locational, marginal pricing at each generation location rather than establishing pricing in four zones as was done prior to December 1, 2010. As a result of the new nodal market, we were required to post additional collateral in the form of cash, letters of credit, and the issuance of additional First Priority Liens of approximately $50 million as of December 31, 2010; however, it is still too early in the implementation process to rule out other potential impacts to our business.

The Sunset Review Process, implemented by the Texas Legislature in 1977, is the regular assessment of the need for a state agency to exist and to consider new and innovative changes to improve each agency's operations and activities. The Sunset Review Process works by setting a date on which an agency will be abolished unless legislation is passed to continue its functions. The Sunset Review Process began in September 2009 for the PUCT and ERCOT and concluded in April 2010. The TCEQ and Texas Railroad Commission reviews began in April 2010 and were completed in December 2010. While significant changes were proposed at the Commission level, we cannot predict which changes, if any, will be placed into legislation and ultimately reach final passage. We will continue to participate in these processes where we anticipate an impact on our business; however, we do not expect such changes, if any, will have a material impact on our operations.

On July 17, 2008, the PUCT tentatively approved a transmission build plan, the Competitive Renewable Energy Zones, or CREZ, to expand the delivery of wind-generated power from western Texas to service approximately 18,500 MW of planned wind generation. Wind generation tends to supply more power during off-peak hours and shoulder months, and is unpredictable. If completed as currently approved, the impact of the transmission upgrades and associated wind generation on our Texas plants is unknown.

North

We have a total of 30 power plants with 7,336 MW of peaking capacity located in the RFC, NPCC and MRO NERC regions.

We have 18 operating power plants with the capacity to generate a total of 3,919 MW and one plant under construction that will have the capacity to generate 565 MW in Eastern PJM. In addition, we have one operating power plant, with the capacity to generate 503 MW, located in Western PJM. However, this power plant is partially committed to load in MISO. Eastern PJM and Western PJM are both located in the RFC NERC region. PJM operates wholesale power markets, a locationally based capacity market, a forward capacity market and ancillary service markets. PJM also performs transmission planning for the region.

Recently, certain states in the PJM region have taken actions that could impact the PJM capacity market. The Maryland Public Service Commission ("PSC") has issued for public comment a draft Request for Proposals ("RFP") for up to 1,800 MW of new generation. Similarly, in New Jersey, recently passed legislation requires the Board of Public Utilities ("BPU") to solicit interest in 2,000 MW of new generation. Either or both of these efforts may result in the award of long term contracts that could impact the clearing prices of future PJM capacity auctions. The actual impact on capacity auction prices will in part depend on the ultimate outcome of the various state regulatory proceedings (which may be subject to legal challenge) and potential FERC action on PJM tariff provisions that are designed to prevent the abuse of buyer-side market power and artificial price suppression. On February 1, 2011, an industry trade group has filed a FPA Section 206 complaint at FERC, requesting that FERC address this matter on an expedited basis. On February 11, 2011, PJM filed proposed tariff changes under Section 205 of the FPA to address this matter as well. FERC action in both proceedings is pending. Also, on February 9, 2011, we joined a group of generators and utilities in filing a complaint in federal district court challenging the constitutionality of the New Jersey legislation. We cannot predict at this time how FERC or the court will respond to these various challenges or what impact the legislation will have on our business.

We have a total of eight natural gas-fired power plants with the capacity to generate a total of 1,433 MW in the NPCC NERC region. Five of these power plants are located in New York. NYISO manages the transmission system in New York and operates the state's wholesale power markets. NYISO manages both day-ahead and real-time energy markets using a locationally based marginal pricing mechanism that pays each generator the zonal marginally accepted bid price for the energy it produces.

Our remaining U.S.-based power plant in the NPCC NERC region is located in Maine. ISO NE is the Regional Transmission Organization for Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. ISO NE has broad authority over the day-to-day operation of the transmission system and operates a day-ahead and real-time wholesale energy market, a forward capacity market and ancillary services markets. ISO NE also provides for regional transmission planning.

We also have 50% ownership interests in two Canadian power plants, with the total capacity to generate 1,088 MW (544 MW net Calpine), located in the NPCC NERC region in Ontario, Canada. The Whitby cogeneration facility is a 50 MW facility located in Whitby, Ontario and the Greenfield Energy Centre is a 1,038 MW facility located in Courtright, Ontario. The Independent Electricity System Operator ("IESO") of Ontario operates the Province's wholesale power markets and directs the operation and ensures reliability of the IESO controlled grid. Hydro-One owns and operates the transmission system in Ontario, which is regulated by the Ontario Energy Board. Effective December 2009, the IESO implemented certain interim market rule changes which impacted the financial performance of Greenfield Energy Centre in 2010. Further related rule changes will be implemented by the IESO in the fall of 2011, which will also affect Greenfield Energy Centre's financial performance. Greenfield Energy Centre's power supply contract with the Ontario Power Authority provides a mechanism to revise the contract to alleviate financial impacts of market rule changes on Greenfield Energy Centre. The parties have not reached agreement on the scope of relief to be provided under the contract and discussions continue between the parties on this issue.

We have three natural gas-fired power plants with the capacity to generate a total of 1,481 MW operating within the MRO NERC region. MISO manages competitive locationally based wholesale day-ahead, real-time energy and ancillary services markets. MISO's Resource Adequacy model requires load serving entities to account for capacity obligations under Module E of the MISO tariff. MISO implemented a monthly voluntary capacity auction to help purchasers find suppliers with capacity to meet their incremental capacity needs. MISO has stated that it plans to make a filing with FERC in June 2011 which purportedly will enhance some aspects of its current resource adequacy construct, including moving from a monthly to annual capacity period and possibly adding a forward commitment period and annual auctions.

Southeast

We have one operating natural gas-fired power plant with the capacity to generate 1,134 MW located in the SPP NERC region. SPP is a RTO approved by FERC that provides independent administration of the electric power grid. SPP manages an energy-only location based real-time wholesale energy market. This market provides both nominal load-following and transmission constraint relief. SPP stakeholders are considering the creation of a day-ahead market and ancillary service markets.

We have ten natural gas-fired power plants with the capacity to generate a total of 4,949 MW operating within the SERC and the FRCC NERC regions. Opportunities to negotiate bilateral, individual contracts and long-term transactions with investor owned utilities, municipalities and cooperatives exist within these regions. In addition to entering into bilateral transactions, there is a limited opportunity to sell into the short-term market. In the Entergy sub-region, SPP has been designated as the Independent Coordinator of Transmission. In this capacity, the Independent Coordinator of Transmission provides oversight of the Entergy transmission system.

Other State Regulation of Power

State Public Utility Commissions, or PUC(s), 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 all of our affiliates are either QFs or EWGs, none of our affiliates are currently subject to direct rate regulation by a state PUC. However, states may assert jurisdiction over the siting and construction of power 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. In California, for example, the CPUC was required by statute to adopt and enforce maintenance and operation standards for power plants "located in the state," including EWGs but excluding QFs, for the purpose of ensuring their reliable operation. As the owner and operator of power plants in California, our subsidiaries are subject to the power plant maintenance and operation standards and the general duty standards that are enforced by the CPUC.

State PUCs also maintain extensive control over the procurement of wholesale power by the utilities that they regulate. Many of these utilities are our customers, and agreements between us and these counterparties often require approval by state PUCs. For example, in California, the CPUC determines how much new generation can be purchased by the IOUs, and shapes the rules of the IOUs' requests for offers. In addition, the CPUC determines the rules of California's Resource Adequacy program. The Resource Adequacy program is currently based on a loosely structured year- and month-ahead bilateral capacity market.

Regulation of Transportation and Sale of Natural Gas

Since the majority of our power generating capacity is derived from natural gas-fired power plants, we are broadly impacted by federal regulation of natural gas transportation and sales. Furthermore, our two natural gas transportation pipelines in Texas are subject to dual jurisdiction by FERC and the Texas Railroad Commission. These pipelines are intrastate pipelines within the meaning of Section 2(16) of the Natural Gas Policy Act ("NGPA"). FERC regulates the rates charged by these pipelines for transportation services performed under Section 311 of the NGPA, and the Texas Railroad Commission regulates the rates and services provided by these pipelines as gas utilities in Texas. Additionally, under the Natural Gas Act ("NGA"), the NGPA and the Outer Continental Shelf Lands Act, FERC is authorized to regulate pipeline, storage and liquefied natural gas, or LNG, facility construction; the transportation of natural gas in interstate commerce; the abandonment of facilities; and the rates for services. FERC is also authorized under the NGA to regulate the sale of natural gas at wholesale.

FERC has civil penalty authority for violations of the NGA and NGPA, as well as any rule or order issued thereunder. FERC's regulations specifically prohibit the manipulation of the natural gas markets by making it unlawful for any entity in connection with the purchase or sale of natural gas, or the purchase or sale of transportation service under FERC's jurisdiction, to engage in fraudulent or deceptive practices. Similar to its penalty authority under the FPA described above, FERC is authorized to assess a maximum civil penalty of $1 million per violation for each day that the violation continues. The NGA and NGPA also provide for the assessment of criminal fines and imprisonment time for violations.

We also operate proprietary pipelines in California, which are regulated by the California Department of Transportation with regard to safety matters but are otherwise not regulated.

CFTC Regulation of Power and Natural Gas and Derivatives Legislation

The CFTC has regulatory oversight of the futures markets, including trading on NYMEX for energy, and licensed futures professionals such as brokers, clearing members and large traders. In connection with its oversight of the futures markets and NYMEX, the CFTC regularly investigates market irregularities and potential manipulation of those markets. Recent laws also give the CFTC certain powers with respect to broker-type markets referred to as "exempt commercial markets" or ECMs, including the Intercontinental Exchange. The CFTC monitors activities in the OTC, ECM, and physical markets that may be undertaken for the purpose of influencing futures prices. With respect to ECMs, the CFTC exercises only light-handed regulation primarily related to price reporting and record retention. Thus, transactions executed on an ECM generally are not regulated directly by the CFTC. However, ECM transactions have come under the CFTC's scrutiny during investigations of fraud and manipulation in which the CFTC has broadly applied its statutory authority to punish persons who are alleged to have manipulated, or attempted to manipulate, the price of any commodity in interstate commerce or for future delivery. We also expect the CFTC's future powers and oversight to be increased by the Dodd-Frank Act (discussed below).

The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010

The Dodd-Frank Act was signed into law on July 21, 2010. Many aspects of the Dodd-Frank Act are subject to rulemaking that will take effect over several years, thus making it difficult to assess its impact on us at this time. The Dodd-Frank Act contains a variety of provisions designed to regulate financial markets, including credit and derivatives transactions.

Derivatives — Title VII of the Dodd-Frank Act addresses regulatory reform of the OTC derivatives market in the U.S. and significantly changes the regulatory framework of this market. Title VII will be effective 360 days from the enactment of the Dodd-Frank Act and the implementing regulation is to be completed by the same date. Until these regulations have been finalized, the extent to which the provisions of Title VII might affect our derivatives activities is unknown. A number of features of the legislation may impact our existing business. One of the most significant of these is the requirement for central clearing of many OTC derivatives transactions with clearing organizations. This requirement is subject to an end-user exception. Whereas our OTC transactions have traditionally been negotiated on a bilateral basis, including the collateral arrangements thereunder, they now will be subject to the collateral and margining procedures of the clearing organization. To the extent the end-user exception is available to us, we may elect not to clear certain transactions. In these instances, the collateral margining requirements for these uncleared transactions might be subject to the requirements prescribed by this regulation. It is not known at this time whether, and, if so, to what extent, we will be required to provide collateral (for both our cleared and uncleared transactions) in excess of what is currently provided under our existing hedging relationships. Other features of the Dodd-Frank Act which will have an impact on our derivatives activities include trade reporting, position limits and trade execution. The effect of the Dodd-Frank Act on traditional dealers and market-makers as well as the consequential effect on market liquidity and, hence, pricing is uncertain; however, we expect to be able to continue to participate in financial markets for our derivative transactions.

Other provisions — The Dodd-Frank Act also requires regulatory agencies, including the SEC, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act. We may incur additional costs associated with our compliance with the new regulations and anticipated additional reporting and disclosure obligations. We will continue to monitor all relevant developments and rule-making initiatives in the implementation of the Dodd-Frank Act and we expect to successfully implement any new applicable legislative and regulatory requirements; however, we do not expect any additional costs related to the implementation of potential future requirements under the Dodd-Frank Act to be material to us.

Geothermal Operations

Commencing in 2009, a geothermal company's activities to engineer or create a "multilayered heat extraction system" on property adjacent to our Geysers Assets by injecting water under very high pressure spawned public and political concern regarding possible increased seismicity risk from geothermal exploration and development. This company has since officially announced its decision to not move forward with this project, but prior to this announcement, the resulting community concern related to this project brought forth a letter from a local community homeowners association located near our Geysers Assets entitled a "Complaint and Petition" which was signed by "109 residents and property owners." This letter was sent to the Board of Supervisors for the two counties, Lake and Sonoma, where our operations are situated. The letter requested county intervention to abate alleged public nuisance arising from induced seismicity by governmental legal action, including litigation, regulation and ordinances to prevent induced seismicity. However, the letter also stated that it is not their intent to suspend our geothermal operations.

While it still is possible that government entities or agencies will seek to more stringently regulate the exploration, development and operation of geothermal power plants, including our Geysers Assets, in order to mitigate induced seismicity resulting from geothermal operations, no further action has been taken at the local level in response to the community's "Complaint and Petition." We have also taken extra steps to increase and broaden our local community outreach efforts.

EMPLOYEES

As of December 31, 2010, we employed 2,142 full-time employees, of whom 184 were represented by collective bargaining agreements. We have never experienced a work stoppage or strike.

Item 1A. *Risk Factors*

Commercial Operations

Our financial performance is impacted by price fluctuations in the wholesale power and natural gas markets and other market factors that are beyond our control.

Market prices for power, generation capacity, ancillary services, natural gas and fuel oil are unpredictable and fluctuate substantially. Unlike most other commodities, power can only be stored on a very limited basis and generally must be produced concurrently with its use. As a result, power prices are subject to significant volatility due to supply and demand imbalances, especially in the day-ahead and spot markets. Long- and short-term power and natural gas prices may also fluctuate substantially due to other factors outside of our control, including:

- increases and decreases in generation capacity in our markets, including the addition of new supplies of power as a result of the development of new power plants, expansion of existing power plants or additional transmission capacity;
- changes in power transmission or fuel transportation capacity constraints or inefficiencies;
- power supply disruptions, including power plant outages and transmission disruptions;
- Heat Rate risk;
- weather conditions;
- quarterly and seasonal fluctuations;
- changes in the demand for power or in patterns of power usage, including the potential development of demand-side management tools and practices;
- development of new fuels or new technologies for the production of power;
- regulations and actions of the ISOs;
- federal and state power, market and environmental regulation and legislation, including mandating a RPS or creating financial incentives, each resulting in new renewable energy generation capacity creating oversupply;
- changes in prices related to RECs; and
- changes in capacity prices and capacity markets.

These factors have caused our operating results to fluctuate in the past and will continue to cause them to do so in the future.

Our revenues and results of operations depend on market rules, regulation and other forces beyond our control.

Our revenues and results of operations are influenced by factors that are beyond our control, including:

- rate caps, price limitations and bidding rules imposed by ISOs, Regional Transmission Organizations and other market regulators that may impair our ability to recover our costs and limit our return on our capital investments;
- some of our competitors (mainly utilities) receive entitlement-guaranteed rates of return on their capital investments, with returns that exceed market returns and may impact our ability to sell our power at economical rates;
- structure and operating characteristics of our capacity markets such as our PJM capacity auctions and our NYISO markets; and
- regulations and market rules related to our RECs.

Accounting for our hedging activities may increase the volatility in our quarterly and annual financial results.

We engage in commodity-related marketing and price-risk management activities in order to economically hedge our exposure to market risk with respect to power sales from our power plants, fuel utilized by those assets and emission allowances. We generally attempt to balance our fixed-price physical and financial purchases, and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative contracts. These derivatives are accounted for under U.S. GAAP, which requires us to record all derivatives on the balance sheet at fair value unless they qualify for the normal purchase normal sale exemption. Changes in the fair value resulting from fluctuations in the underlying commodity prices are immediately recognized in earnings, unless the derivative qualifies for, and is designated as, cash flow hedge accounting treatment. Sudden commodity price movements could create financial gains or losses. Whether a derivative qualifies for cash flow hedge accounting treatment depends upon it meeting specific criteria used to determine if the cash flow hedge is and will remain effective for the term of the derivative. Economic hedges will not necessarily qualify for cash flow hedge accounting treatment, or for economic hedges that currently qualify for cash flow hedge accounting treatment; we may lose cash flow hedge accounting treatment in the future if the forecasted transactions are no longer considered probable of occurring. Additionally, we may voluntarily decide to discontinue cash flow treatment in the future. As a result, we may be unable to accurately predict the impact that our risk management decisions may have on our quarterly and annual financial results.

The use of hedging agreements may not work as planned or fully protect us and could result in financial losses.

We typically enter into hedging agreements, including contracts to purchase or sell commodities at future dates and at fixed prices, in order to manage our commodity price risks. These activities, although intended to mitigate price volatility, expose us to other risks. When we sell power forward, we may be required to post significant amounts of cash collateral or other credit support to our counterparties and we give up the opportunity to sell power at higher prices if spot prices are higher in the future. Further, if the values of the financial contracts change in a manner that we do not anticipate, or if a counterparty fails to perform under a contract, it could harm our financial condition, results of operations and cash flows.

We do not typically hedge the entire exposure of our operations against commodity price volatility. To the extent we do not hedge against commodity price volatility, our financial condition, results of operations and cash flows may be diminished based upon adverse movement in commodity prices.

Our ability to manage our counterparty credit risk could adversely affect us.

Our customer and supplier counterparties may experience deteriorating credit. These conditions could cause counterparties in the natural gas and power markets, particularly in the energy commodity derivative markets that we rely on for our hedging activities, to withdraw from participation in those markets. If multiple parties withdraw from those markets, market liquidity may be threatened, which in turn could adversely impact our business. Additionally, these conditions may cause our counterparties to seek bankruptcy protection under Chapter 11 or liquidation under Chapter 7 of the Bankruptcy Code. Our credit risk may be exacerbated to the extent collateral held by us cannot be realized or is liquidated at prices not sufficient to recover the full amount of the derivative exposure due to us. There can be no assurance that any such losses or impairments to the carrying value of our financial assets would not materially and adversely affect our financial condition, results of operations and cash flows.

Competition could adversely affect our performance.

The power generation industry is characterized by intense competition, and we encounter competition from utilities, industrial companies, marketing and trading companies and other independent power producers. In addition, many states are implementing or considering regulatory initiatives designed to increase competition in the domestic power industry. This competition has put pressure on power utilities to lower their costs, including the cost of purchased power, and increasing competition in the supply of power in the future could increase this pressure. In addition, construction during the last decade has created excess power supply and higher reserve margins in the power trading markets, putting downward pressure on prices.

In certain situations, our PPAs and other contractual arrangements, including construction agreements, commodity contracts, maintenance agreements and other arrangements, may be terminated by the counterparty and/or may allow the counterparty to seek liquidated damages.

The situations that could allow a counterparty to terminate the contract and/or seek liquidated damages include:

- the cessation or abandonment of the development, construction, maintenance or operation of a power plant;
- failure of a power plant to achieve construction milestones or commercial operation by agreed-upon deadlines;
- failure of a power plant to achieve certain output or efficiency minimums;
- our failure to make any of the payments owed to the counterparty or to establish, maintain, restore, extend the term of, or increase any required collateral;
- failure of a power plant to obtain material permits and regulatory approvals by agreed-upon deadlines;
- a material breach of a representation or warranty or our failure to observe, comply with or perform any other material obligation under the contract; or
- events of liquidation, dissolution, insolvency or bankruptcy.

Revenue may be reduced significantly upon expiration or termination of our PPAs.

Some of the power we generate from our existing portfolio is sold under long-term PPAs that expire at various times. We also sell power under short- to intermediate-term (one day to five years) PPAs. Our uncontracted capacity is generally sold on the spot market at current market prices as merchant energy. When the terms of each of our various PPAs expire, it is possible that the price paid to us for the generation of power under subsequent arrangements or on the spot market may be significantly less than the price that had been paid to us under the PPA. Power plants without long-term PPAs involve risk and uncertainty in forecasting future demand load for merchant sales because they are exposed to market fluctuations for some or all of their generating capacity and output. A significant under- or over-estimation of load requirements may increase our operating costs. Without the benefit of long-term PPAs, we may not be able to sell any or all of the power generated by these power plants at commercially attractive rates and these power plants may not be able to operate profitably. Certain of our PPAs have values in excess of current market prices. We are at risk of loss of margins to the extent that these contracts expire or are terminated and we are unable to replace them on comparable terms. Additionally, our PPAs contain termination provisions standard to contracts in our industry such as negligence, performance default or prolonged events of force majeure.

A prolonged economic downturn could result in a reduction in our revenue and operating cash flows or result in our customers, counterparties, vendors or other service providers failing to perform under their contracts with us.

To the extent that an economic downturn returns and affects the markets in which we operate, demand for power and power prices may be depressed, and our revenues and operating cash flows could be negatively impacted. In addition, challenges currently affecting the economy could cause our customers, counterparties, vendors and service providers to experience deteriorating credit and serious cash flow problems. As a result, these conditions could cause counterparties in the natural gas and power markets, particularly in the energy commodity derivative markets that we rely on for our hedging activities, to be unable to perform under existing contracts, or to withdraw from participation in those markets. If multiple parties withdraw from those markets, market liquidity may be threatened, which in turn could adversely impact our business. Additionally, these conditions may cause our counterparties to seek bankruptcy protection under Chapter 11 or liquidation under Chapter 7 of the Bankruptcy Code.

Power Operations

Our power generating operations performance involves significant risks and hazards and may be below expected levels of output or efficiency.

The operation of power plants involves risks, including the breakdown or failure of power generation equipment, transmission lines, pipelines or other equipment or processes, performance below expected levels of output or efficiency and risks related to the creditworthiness of our contract counterparties and the creditworthiness of our counterparties' customers or other parties, such as steam hosts, with whom our counterparties have contracted. From time to time our power plants have experienced unplanned outages, including extensions of scheduled outages due to equipment breakdowns, failures or other problems and are an inherent risk of our business. Unplanned outages typically can result in lost revenues, increase our maintenance expenses and may reduce our profitability, which could have a material adverse effect on our financial condition, results of operations and cash flows.

In addition, an unplanned outage may prevent the affected power plant from performing under any applicable PPAs, commodity contracts or other contractual arrangements. Such failure may allow a counterparty to terminate an agreement and/or seek liquidated damages. Although insurance is maintained to partially 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, or may otherwise breach, our financing obligations, particularly with respect to the affected power plant, which could result in losing our interest in the affected power plant or, possibly, one or more other power plants.

We may be subject to future claims, litigation and enforcement

Our power generating operations are inherently hazardous and may lead to catastrophic events, including loss of life, personal injury and destruction of property, and subject us to litigation. Natural gas is highly explosive and power generation involves hazardous activities, including acquiring, transporting and delivering fuel, operating large pieces of rotating equipment and delivering power to transmission and distribution systems. These and other hazards can cause severe damage to and destruction of property, plant and equipment and suspension of operations. In the worst circumstances, catastrophic events can cause significant personal injury or loss of life. Further, the occurrence of any one of these events may result in us being named as a defendant in lawsuits asserting claims for substantial damages. We maintain an amount of insurance protection that we consider adequate; however, we cannot provide any assurance that the insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we are subject.

Additionally, we are party to various litigation matters, including regulatory and administrative proceedings arising out of the normal course of business.

We review our litigation activities and determine if an unfavorable outcome to us is considered "remote," "reasonably possible" or "probable" as defined by U.S. GAAP. Where we have determined an unfavorable outcome is probable and is reasonably estimable, we have accrued for potential litigation losses.

A successful claim against us that is not fully insured could be material; however, we do not expect that the outcome of such claims or legal actions will have a material adverse effect on our financial position or results of operations. See also Note 15 of the Notes to Consolidated Financial Statements for a description of our more significant litigation matters.

We rely on power transmission and fuel distribution facilities owned and operated by other companies.

We depend on facilities and assets that we do not own or control for the transmission to our customers of the power produced by our power plants and the distribution of natural gas fuel or fuel oil to our power plants. If these transmission and distribution systems are disrupted or capacity on those systems is inadequate, our ability to sell and deliver power products or obtain fuel may be hindered. ISOs that oversee transmission systems in regional power markets have imposed price limitations and other mechanisms to address volatility in their power markets. Existing congestion, as well as expansion of transmission systems, could affect our performance.

Our power project development and construction activities involve risk and may not be successful.

The development and construction of power plants is subject to substantial risks. In connection with the development of a power plant, we must generally obtain:

- necessary power generation equipment;
- governmental permits and approvals including environmental permits and approvals;
- fuel supply and transportation agreements;
- sufficient equity capital and debt financing;
- power transmission agreements;
- water supply and wastewater discharge agreements or permits; and
- site agreements and construction contracts.

To the extent that our development and construction activities continue or expand, we may be unsuccessful on a timely and profitable basis. Although we may attempt to minimize the financial risks of these activities by securing a favorable PPA and arranging adequate financing prior to the commencement of construction, the development of a power project may require us to expend significant cash sums for preliminary engineering, permitting, legal and other expenses before we can determine whether a project is feasible, economically attractive or financeable. The process for obtaining governmental permits and approvals is complicated and lengthy, often taking more than one year, and is subject to significant uncertainties. We may be unable to obtain all necessary licenses, permits, approvals and certificates for proposed projects, and completed power plants may not comply with all applicable permit conditions, statutes or regulations. In addition, regulatory compliance for the construction and operation of our power plants can be a costly and time-consuming process. Intricate and changing environmental and other regulatory requirements may necessitate substantial expenditures to obtain and maintain permits. If a project is unable to function as planned due to changing requirements, loss of required permits or regulatory status or local opposition, it may create expensive delays, extended periods of non-operation or significant loss of value in a project resulting in potential impairments.

We may be unable to obtain an adequate supply of fuel in the future.

We obtain substantially all of our physical natural gas and fuel oil supply from third parties pursuant to arrangements that vary in term, pricing structure, firmness and delivery flexibility. Our physical natural gas and fuel oil supply arrangements must be coordinated with transportation agreements, balancing agreements, storage services, financial hedging transactions and other contracts so that the natural gas and fuel oil is delivered to our power plants at the times, in the quantities and otherwise in a manner that meets the needs of our generation portfolio and our customers. We must also comply with laws and regulations governing natural gas transportation.

While adequate supplies of natural gas and fuel oil are currently available to us at prices we believe are reasonable for each of our power plants, we are exposed to increases in the price of natural gas and fuel oil and it is possible that sufficient supplies to operate our portfolio profitably may not continue to be available to us. In addition, we face risks with regard to the delivery to and the use of natural gas and fuel oil by our power plants including the following:

- transportation may be unavailable if pipeline infrastructure is damaged or disabled;
- pipeline tariff changes may adversely affect our ability to, or cost to, deliver natural gas and fuel oil supply;
- third-party suppliers may default on natural gas supply obligations and we may be unable to replace supplies currently under contract;
- market liquidity for physical natural gas and fuel oil or availability of natural gas and fuel oil services (e.g. storage) may be insufficient or available only at prices that are not acceptable to us;
- natural gas and fuel oil quality variation may adversely affect our power plant operations;
- our natural gas and fuel oil operations capability may be compromised due to various events such as natural disaster, loss of key personnel or loss of critical infrastructure; and
- any other reason such as for residential heating.

Our power plants and construction projects are subject to impairments.

If we were to experience a significant reduction in our expected revenues and operating cash flows for an extended period of time from a prolonged economic downturn or from advances or changes in technologies, we could experience future impairments of our power plant assets as a result. There can be no assurance that any such losses or impairments to the carrying value of our financial assets would not materially and adversely affect our financial condition, results of operations and cash flows.

Our geothermal power reserves may be inadequate for our operations.

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 power capacity desired. In addition, we may not be able to successfully manage the development and operation of our geothermal reservoirs or accurately estimate the quantity or productivity of our steam reserves. An incorrect estimate or inability to manage our geothermal reserves, or a decline in productivity could adversely affect our results of operations or financial condition. In addition, the development and operation of geothermal power resources are subject to substantial risks and uncertainties. The successful exploitation of a geothermal power resource ultimately depends upon many factors including the following:

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

Claims that some geothermal power plants cause increased risk of seismic activity could impact our operating procedures and increase our operating costs or, delay or increase the cost of further development at The Geysers.

In 2009, as part of a joint private and federally-funded geothermal technology research project, a company unrelated to us commenced deepening an existing geothermal well on a property neighboring our Geysers Assets. The company was reportedly attempting to drill into the hot, low or non-permeable base rock that underlies the existing geothermal steam reservoir at The Geysers to engineer or create a "multilayered heat extraction system" below the reservoir by injecting water under very high pressure, fracturing the rock. This process has spawned public and political concern regarding increased seismicity risk. This company has since officially announced its decision to not move forward with this project, but prior to this announcement, the resulting community concern related to this project brought forth a letter from a local community homeowners association located near our Geysers Assets entitled a "Complaint and Petition" which was signed by "109 residents and property owners." This letter was sent to the Board of Supervisors' for the two counties, Lake and Sonoma, where our operations are situated. The letter requested county intervention to abate alleged public nuisance arising from induced seismicity by governmental legal action, including litigation, regulation and ordinances to prevent induced seismicity. However, the letter also stated that it is not their intent to suspend our geothermal operations. No further action has been taken at the local level in response to the community's "Complaint and Petition." We have also taken extra steps to increase and broaden our local community outreach efforts.

It is possible that government entities or agencies will seek to more stringently regulate the exploration, development and operation of geothermal power plants, including operations of our Geysers Assets, in order to mitigate induced seismicity resulting from geothermal operations, or that operators of geothermal power plants could be subject to property damage claims resulting from increased seismic activity. Any of these events could increase the cost of operating the existing Geysers Assets and may delay or increase further exploration and any further development of our Geysers Assets.

Significant events beyond our control, such as natural disasters or acts of terrorism, could damage our power plants or our corporate offices and may impact us in unpredictable ways.

Certain of our geothermal and natural gas-fired power plants, particularly in the West, are subject to frequent low-level seismic disturbances. More significant seismic disturbances are possible. In addition, other areas in which we operate, particularly in Texas and the Southeast, experience tornados and hurricanes. Similarly, operations at our corporate offices in Houston, Texas could be substantially affected by a hurricane. Such events could damage or shut down our power plants, power transmission or the fuel supply facilities upon which our generation business is dependent. Our existing power plants are built to withstand relatively significant levels of seismic and other 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 damages or disturbances to our power plants or our operations due to natural disasters.

In addition to physical damage to our power plants, the risk of future terrorist activity could result in adverse changes in the insurance markets and disruptions in the power and fuel markets. These events could also adversely affect the U.S. economy, create instability in the financial markets and, as a result, have an adverse effect on our ability to access capital on terms and conditions acceptable to us.

We depend on our management and employees.

Our success is largely dependent on the skills, experience and efforts of our people. The loss of the services of one or more members of our senior management or of numerous employees with critical skills could have a negative effect on our business, financial condition and results of operations and future growth if we were unable to replace them.

Some of our employees are represented by collective bargaining agreements.

We have 184 employees represented by collective bargaining agreements; however, the amount of employees subject to collective bargaining agreements only represents a small percentage (approximately 9%) of our employee base. We believe we maintain positive relations with these employees and do not anticipate any work stoppages or strikes.

We depend on computer and telecommunications systems we do not own or control.

We have entered into agreements with third parties for hardware, software, telecommunications and database services in connection with the operation of our power plants. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. In addition, it is possible we could incur interruptions from computer viruses. We believe that we have positive relations with our related vendors and maintain adequate anti-virus software and controls; however, any interruptions to our arrangements with third parties, to our computing and communications infrastructure, or our information systems could significantly disrupt our business operations.

Capital Resources; Liquidity

We have substantial liquidity needs and could face liquidity pressure.

As of December 31, 2010, our consolidated debt outstanding was $10.3 billion, of which approximately $4.7 billion was outstanding under our First Lien Notes and $1.2 billion under our First Lien Credit Facility. In addition we had $711 million issued in letters of credit and our pro rata share of unconsolidated subsidiary debt was approximately $247 million. Although we have significantly extended our maturities during 2010 and 2011, we could face liquidity challenges as we continue to have substantial debt and substantial liquidity needs in the operation of our business. Our ability to make payments on our indebtedness, to meet margin requirements and to fund planned capital expenditures and development efforts will depend on our ability to generate cash in the future from our operations and our ability to access the capital markets. This, to a certain extent, is dependent upon industry conditions, as well as general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control, as discussed further in "— Commercial Operations" above. Although we are permitted to enter into new project financing credit facilities to fund our development and construction activities, there can be no assurance that we will not face liquidity pressure in the future. See additional discussion regarding our capital resources and liquidity in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

Our substantial indebtedness could adversely impact our financial health and limit our operations.

Our level of indebtedness has important consequences, including:

- limiting our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, potential growth or other purposes;
- limiting our ability to use operating cash flows in other areas of our business because we must dedicate a substantial portion of these funds to service our debt;
- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to capitalize on business opportunities, and to react to competitive pressures and adverse changes in governmental regulation;
- limiting our ability or increasing the costs to refinance indebtedness or to repurchase equity issued by certain of our subsidiaries to third parties; and

- limiting our ability to enter into marketing, hedging and optimization activities by reducing the number of counterparties with whom we can transact as well as the volume and type of those transactions.

The soundness of financial institutions could adversely affect us.

We have exposure to many different financial institutions and counterparties including those under our First Lien Notes and Corporate Revolving Facility and other credit and financing arrangements as we routinely execute transactions in connection with our hedging and optimization activities, including brokers and dealers, commercial banks, investment banks and other institutions and industry participants. Many of these transactions expose us to credit risk in the event that any of our lenders or counterparties are unable to honor their commitments or otherwise defaults under a financing agreement.

We may be unable to obtain additional financing or access the credit and capital markets in the future at prices that are beneficial to us or at all.

If our available cash, including future cash flows generated from operations, is not sufficient in the near term to finance our operations, post collateral or satisfy our obligations as they become due, we may need to access the capital and credit markets. Our ability to arrange financing (including any extension or refinancing) and the cost of the financing are dependent upon numerous factors, including general economic and capital market conditions. Market disruptions such as those experienced in the U.S. and abroad in 2008 and 2009, may increase our cost of borrowing or adversely affect our ability to access capital. In addition, we believe these conditions have and may continue to have an adverse effect on the price of our common stock, which in turn may also reduce our ability to access capital or credit markets. Other factors include:

- low credit ratings may prevent us from obtaining any material amount of additional debt financing;
- conditions in energy commodity markets;
- regulatory developments;
- credit availability from banks or other lenders for us and our industry peers;
- investor confidence in the industry and in us;
- the continued reliable operation of our current power plants; and
- provisions of tax, regulatory and securities laws that are conducive to raising capital.

While we have utilized non-recourse or lease financing when appropriate, market conditions and other factors may prevent us from completing similar financings in the future. It is possible that we may be unable to obtain the financing required to develop, construct, acquire or expand power plants on terms satisfactory to us. We have financed our existing power plants using a variety of leveraged financing structures, including senior secured and unsecured indebtedness, construction financing, project financing, term loans and lease obligations. 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 power plant and any related assets. In the event of foreclosure after a default, we may not be able to retain any interest in the power plant or other collateral supporting such financing. In addition, any such default or foreclosure may trigger cross default provisions in our other financing agreements.

Our First Lien Notes, Corporate Revolving Facility, NDH Project Debt and CCFC Notes, and our other debt instruments impose restrictions on us and any failure to comply with these restrictions could have a material adverse effect on our liquidity and our operations.

The restrictions under our First Lien Notes, Corporate Revolving Facility, NDH Project Debt and CCFC Notes and other debt instruments could adversely affect us by limiting our ability to plan for or react to market conditions or to meet our capital needs and, if we were unable to comply with these restrictions, could result in an event of default under these debt instruments. These restrictions require us to meet certain financial performance tests on a quarterly basis and limit or prohibit our ability, subject to certain exceptions to, among other things:

- incur or guarantee additional first lien indebtedness up to certain consolidated net tangible asset ratios;
- enter into certain types of commodity hedge agreements that can be secured by first lien collateral;
- enter into sale and leaseback transactions;
- make certain investments;
- create or incur liens;
- consolidate or merge with or transfer all or substantially all of our assets to another entity, or allow substantially all of our subsidiaries to do so;
- lease, transfer or sell assets and use proceeds of permitted asset leases, transfers or sales;
- engage in certain business activities; and
- enter into certain transactions with our affiliates.

Our First Lien Notes, Corporate Revolving Facility, NDH Project Debt and CCFC Notes and our other debt instruments contain events of default customary for financings of their type, including a cross default to debt other than non-recourse project financing debt, a cross-acceleration to non-recourse project financing debt and certain change of control events. If we fail to comply with the covenants and are unable to obtain a waiver or amendment, or a default exists and is continuing under such debt, the lenders or the holders or trustee of the First Lien Notes, as applicable, could give notice and declare outstanding borrowings and other obligations under such debt immediately due and payable.

Our ability to comply with these covenants may be affected by events beyond our control, and any material deviations from our forecasts could require us to seek waivers or amendments of covenants or alternative sources of financing or to reduce expenditures. We may not be able to obtain such waivers, amendments or alternative financing, or if obtainable, it could be on terms that are not acceptable to us. If we are unable to comply with the terms of our First Lien Notes, Corporate Revolving Facility, NDH Project Debt and CCFC Notes and our other debt instruments, or if we fail to generate sufficient cash flows from operations, or if it becomes necessary to obtain such waivers, amendments or alternative financing, it could adversely impact our financial condition, results of operations and cash flows.

We may be subject to claims that were not discharged in our Chapter 11 cases.

On December 20, 2005 (the Petition Date), Calpine Corporation and 274 of its wholly owned U.S. subsidiaries filed for voluntary petitions of relief under Chapter 11 of the Bankruptcy Code. From the Petition Date through our emergence from Chapter 11 on the Effective Date (January 31, 2008), we operated as a debtor-in-possession under the protection of the U.S. Bankruptcy Court. In general, all claims that arose prior to the Petition Date and before confirmation of our Plan of Reorganization were discharged in accordance with the Bankruptcy Code and the terms of our Plan of Reorganization.

However, certain disputed claims, including prepayment premium and default interest claims asserted by the holders of CalGen Third Lien Debt, may be required to be settled with available cash and cash equivalents to the extent reorganized Calpine Corporation common stock held in reserve pursuant to our Plan of Reorganization for such claims is insufficient in value to satisfy such claims in full. In order for us to be required to make any settlements in cash, our stock price would need to significantly deteriorate below our stock prices during the period from our emergence through the filing of this Report. We consider such an outcome to be unlikely. Additionally, we dispute allegations that the CalGen Third Lien Debt have claims that remain unsettled or outstanding, or that they continue to have lien rights to the assets of the CalGen entities for the pending claims asserted in the case styled: *HSBC Bank USA, NA as Indenture Trustee, et al v. Calpine Corporation, et al. Case No. 1: 07-cv-03088, S.D.N.Y.* Recently the district court in the above litigation issued a decision that the holders of the CalGen Third Lien Debt were not entitled, as a matter of law, to a prepayment premium or to attorney's fees associated with the payoff of the underlying obligations. Further, the district court determined that the holders of the CalGen Third Lien Debt were only entitled to interest as specified in the supporting debt agreements, but did not rule on the issue of this entitlement to default interest on their claims. We believe the holders of the CalGen Third Lien Debt will file an appeal of the judgment entered by the district court. We continue to engage in settlement discussions with the various constituencies in this dispute, but do not expect any settlement, if any, to be material to us.

Our credit status is below investment grade, which may restrict our operations, increase our liquidity requirements and restrict financing opportunities.

Our corporate and debt credit ratings are below investment grade. There is no assurance that our credit ratings will improve in the future, which may restrict the financing opportunities available to us or may increase the cost of any available financing. Our current credit rating has resulted in the requirement that we provide additional collateral in the form of letters of credit or cash for credit support obligations on our subsidiaries' and our financial position and results of operations.

Certain of our obligations are required to be secured by letters of credit or cash, which increase our costs; if we are unable to provide such security it may restrict our ability to conduct our business.

Companies using derivatives, which include many commodity contracts, are subject to the inherent risks of such transactions. Consequently, many such companies, including us, may be required to post cash collateral for certain commodity transactions; and, the level of collateral will increase as a company increases its hedging activities. We use margin deposits, prepayments and letters of credit as credit support for commodity procurement and risk management activities. Future cash collateral requirements may increase based on the extent of our involvement in standard contracts and movements in commodity prices, and also based on our credit ratings and general perception of creditworthiness in this market. Certain of our financing arrangements for our power plants have required us to post letters of credit which are at risk of being drawn down in the event we, or the applicable subsidiary, default on our obligations.

Additionally, changes in market regulations can increase the use of credit support and collateral. For example, we believe that ERCOT's implementation of a nodal market in December 2010 resulted in increased collateral requirements of approximately $50 million as of December 31, 2010. The potential impact of the Dodd-Frank Act is uncertain, but it is possible that future regulations, when finalized, under the Dodd-Frank Act could directly or indirectly result in increased credit support and collateral requirements.

These letter of credit and cash collateral requirements increase our cost of doing business and could have an adverse impact on our overall liquidity, particularly if there was a call for a large amount of additional cash or letter of credit collateral due to an unexpectedly large movement in the market price of a commodity. As of December 31, 2010, we had $711 million issued in letters of credit under our Corporate Revolving Facility and other facilities, with $557 million remaining available for borrowing or for letter of credit support under our Corporate Revolving Facility. In addition, we have ratably secured our obligations under certain of our power and natural gas agreements that qualify as eligible commodity hedge agreements under our Corporate Revolving Facility with the assets currently subject to liens under our First Lien Credit Facility.

We may not have sufficient liquidity to hedge market risks effectively.

We are exposed to market risks through our sale of power, capacity and related products and the purchase and sale of fuel, transmission services and emission allowances. These market risks include, among other risks, volatility arising from location and timing differences that may be associated with buying and transporting fuel, converting fuel into power and delivering the power to a buyer.

We undertake these activities through agreements with various counterparties, many of which require us to provide guarantees, offset or netting arrangements, letters of credit, a second lien on assets and/or cash collateral to protect the counterparties against the risk of our default or insolvency. The amount of such credit support that must be provided typically is based on the difference between the price of the commodity in a given contract and the market price of the commodity. Significant movements in market prices can result in our being required to provide cash collateral and letters of credit in very large amounts. The effectiveness of our strategy may be dependent on the amount of collateral available to enter into or maintain these contracts, and liquidity requirements may be greater than we anticipate or will be able to meet. Without a sufficient amount of working capital to post as collateral in support of performance guarantees or as a cash margin, we may not be able to manage price volatility effectively or to implement our strategy. An increase in the amount of letters of credit or cash collateral required to be provided to our counterparties may negatively affect our liquidity and financial condition.

Further, if any of our power plants experience unplanned outages, we may be required to procure replacement power at spot market prices in order to fulfill contractual commitments. Without adequate liquidity to meet margin and collateral requirements, we may be exposed to significant losses, may miss significant opportunities and may have increased exposure to the volatility of spot markets.

Our ability to receive future cash flows generated from the operation of our subsidiaries may be limited.

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 flows to service our indebtedness, post collateral and finance our ongoing operations. Certain of our project debt and other agreements restrict our ability to receive dividends and other distributions from our subsidiaries. Some of these limitations are subject to a number of significant exceptions (including exceptions permitting such restrictions in connection with certain subsidiary financings). Accordingly, the financing 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 their other obligations, including their outstanding debt, operating expenses, lease payments and reserves, or during the existence of a default.

We may utilize project financing, preferred equity and other types of subsidiary financing transactions when appropriate in the future, which could increase our debt and may be structurally senior to other debt such as our First Lien Notes and Corporate Revolving Facility.

Our ability and the ability of our subsidiaries to incur additional indebtedness are limited in some cases by existing indentures, debt instruments or other agreements. Our subsidiaries may incur additional construction/project financing indebtedness, issue preferred equity to finance the acquisition and development of new power plants and engage in certain types of non-recourse financings to the extent permitted by existing agreements, and may continue to do so in order to fund our ongoing operations. Any such newly incurred subsidiary preferred equity would be added to our current consolidated debt levels and would likely be structurally senior to our debt, which could also intensify the risks associated with our already existing leverage.

Our First Lien Notes, Corporate Revolving Facility and other parent-company debt is effectively subordinated to certain project indebtedness.

Certain of our subsidiaries and other affiliates are separate and distinct legal entities and, except in limited circumstances, have no obligation to pay any amounts due with respect to our indebtedness or indebtedness of other subsidiaries or affiliates, and do not guarantee the payment of interest on or principal of such indebtedness. In the event of our bankruptcy, liquidation or reorganization (or the bankruptcy, liquidation or reorganization of a subsidiary or affiliate), such subsidiaries' or other affiliates' creditors, including trade creditors and holders of debt issued by such subsidiaries or affiliates, will generally be entitled to payment of their claims from the assets of those subsidiaries or affiliates before any assets are made available for distribution to us or the holders of our indebtedness. As a result, holders of our indebtedness will be effectively subordinated to all present and future debts and other liabilities (including trade payables) of certain of our subsidiaries. As of December 31, 2010, our subsidiaries had approximately $1.3 billion of secured project financing from our NDH Project Debt, approximately $1.0 billion in debt from our CCFC subsidiary and approximately $1.8 billion in secured project financing from other subsidiaries, which are effectively senior to our First Lien Notes and Corporate Revolving Facility. We may incur additional project financing indebtedness in the future, which will be effectively senior to our other secured and unsecured debt.

Governmental Regulation

Existing and proposed federal and state RPS and energy efficiency, as well as economic support for renewable sources of power under the U.S economic stimulus legislation could adversely impact our operations.

Federal policymakers have been considering imposing a national RPS on retail power providers. California already has an RPS in effect and is currently considering new and higher RPS. A number of additional states, including Maine, Minnesota, New York, Texas and Wisconsin, have an array of different RPS in place. Existing state-specific RPS requirements may change due to regulatory and/or legislative initiatives, and other states may consider implementing enforceable RPS in the future. A national RPS or more robust RPS in states in which we are active, coupled with economic incentives provided under the federal stimulus package, would likely initially drive up the number of wind and solar resources, increasing power supply to various markets which could negatively impact the dispatch of our natural gas assets, primarily in Texas and California.

Similarly, federal legislators are considering national energy efficiency initiatives. Several states already have energy efficiency initiatives in place while others are considering imposing them. Improved energy efficiency when mandated by law or promoted by government sponsored incentives can decrease demand for power which could negatively impact the dispatch of our gas assets, primarily in Texas and California.

Increased legislation for the construction of power plants, such as those passed by the New Jersey and Maryland state senates could adversely impact our competitive position and business.

Recently, certain states in the PJM region have taken actions that could impact the PJM capacity market. The Maryland Public Service Commission ("PSC") has issued for public comment a draft Request for Proposals ("RFP") for up to 1,800 megawatts of new generation. Similarly, in New Jersey, recently passed legislation requires the Board of Public Utilities ("BPU") to solicit interest in 2,000 MW of new generation. Either or both of these efforts may result in the award of ratepayer-subsidized long term contracts that could impact the clearing prices of future PJM capacity auctions. The actual impact on capacity auction prices will in part depend on the ultimate outcome of the various state regulatory proceedings (which may be subject to legal challenge) and potential FERC action on PJM tariff provisions that are designed to prevent the abuse of buyer-side market power and artificial price suppression. An industry trade group has filed a FPA Section 206 complaint at FERC, requesting that FERC address this matter on an expedited basis.

Increased oversight and investigation by the CFTC relating to derivative transactions, as well as certain financial institutions, could have an adverse impact on our ability to hedge risks associated with our business.

The CFTC has regulatory oversight of the futures markets, including trading on NYMEX for energy, and licensed futures professionals such as brokers, clearing members and large traders. In connection with its oversight of the futures markets and NYMEX, the CFTC regularly investigates market irregularities and potential manipulation of those markets. Recent laws also give the CFTC certain powers with respect to broker-type markets referred to as "exempt commercial markets" or ECMs, including the Intercontinental Exchange. The CFTC monitors activities in the OTC, ECM, and physical markets that may be undertaken for the purpose of influencing futures prices. With respect to ECMs, the CFTC exercises only light-handed regulation primarily related to price reporting and record retention. Thus, transactions executed on an ECM generally are not regulated directly by the CFTC. However, ECM transactions have come under the CFTC's scrutiny during investigations of fraud and manipulation in which the CFTC has broadly applied its statutory authority to punish persons who are alleged to have manipulated, or attempted to manipulate, the price of any commodity in interstate commerce or for future delivery. We also expect the CFTC's future powers and oversight to be increased by the Dodd-Frank Act (discussed below).

The unknown impact from the Dodd-Frank Act as well as the rules to be promulgated under it could have an adverse impact on our ability to hedge risks associated with our business, require the implementation of additional policies and require us to incur administrative compliance costs.

Title VII of the Dodd-Frank Act addresses regulatory reform of the OTC derivatives market in the U.S. and significantly changes the regulatory framework of this market. Title VII will be effective 360 days from the enactment of the Dodd-Frank Act and the implementing regulation is to be completed by the same date. Until these regulations have been finalized, the extent to which the provisions of Title VII might affect our derivatives activities is unknown. A number of features of the legislation may impact our existing business. One of the most significant of these is the requirement for central clearing of many OTC derivatives transactions with clearing organizations. This requirement is subject to an end-user exception which ultimately may or may not be available to us. Whereas our OTC transactions have traditionally been negotiated on a bilateral basis, including the collateral arrangements thereunder, they now will be subject to the collateral and margining procedures of the clearing organization. To the extent the end-user exception is available to us, we may elect not to clear certain transactions. In these instances, the collateral margining requirements for these uncleared transactions might be subject to the requirements prescribed by this regulation. It is not known at this time whether, and, if so, to what extent, we will be required to provide collateral (for both our cleared and uncleared transactions) in excess of what is currently provided under our existing hedging relationships. Other features of the Dodd-Frank Act which will have an impact on our derivatives activities include trade reporting, position limits and trade execution. The effect of the Dodd-Frank Act on traditional dealers and market-makers as well as the consequential effect on or loss of market liquidity on the use of first lien collateral and, hence, pricing is uncertain; however, we expect to be able to continue to participate in financial markets for our derivative transactions.

In addition to legislation and rule making provisions related to derivative transactions, the Dodd-Frank Act contains a variety of provisions designed to regulate financial markets. Further, many aspects of the Dodd-Frank Act are subject to rulemaking that will take effect over several years, thus making it difficult to assess its impact on us at this time. We expect to successfully implement any new applicable legislative and regulatory requirements and may incur additional costs associated with our compliance with the new regulations and anticipated additional reporting and disclosure obligations; however, at this time we do not expect such costs to be material to us.

Changes in the regulation of the power markets in which we operate could negatively impact us.

We have a significant presence in the major competitive power markets for California, Texas and the Mid-Atlantic region of the U.S. While these markets are largely de-regulated, they continue to evolve. Existing regulations within the markets in which we operate may be revised or reinterpreted and new laws or regulations may be issued. We cannot predict the future development of regulation or legislation nor the ultimate effect such changes in these markets could have on our business; however, we could be negatively impacted.

Existing and future anticipated GHG/Carbon and other air emissions regulations could cause us to incur significant costs and adversely affect our operations generally or in a particular quarter when such costs are incurred.

Environmental laws and regulations have generally become more stringent over time, and this trend is likely to continue. In particular, there is growing likelihood that carbon tax or limits on carbon, CO_2 and other GHG emissions will be implemented at the federal or expanded at the state or regional levels.

In 2009, ten states in the northeast began the compliance period of a cap-and-trade program, RGGI, to regulate CO_2 emissions from power plants. California is in the process of implementing plans for AB 32 which places a statewide cap on GHG emissions and requires the state to return to 1990 emission levels by 2020. In December 2010, CARB adopted a regulation establishing a GHG cap-and trade program which takes effect in 2012 for electric utilities and other "major industrial sources," and in 2015 for certain other GHG sources.

Congress proposed but failed to enact climate change legislation in the last session. The November 2010 election resulted in a change in control of Congress with Republicans controlling the U.S. House of Representatives. While the Senate may continue considering legislation addressing climate change, it is unlikely that such legislation will be enacted in the near term. Instead, we expect the current Administration to place more emphasis on increasing the regulations, powers and activities of the EPA under the CAA. In 2010, the EPA proposed or finalized regulations governing GHG emissions from major sources as well as emissions of criteria pollutants from the electric generation sector. The EPA is expected to propose additional regulations under the CAA addressing hazardous air pollutants. Although we cannot predict the ultimate effect of future changes climate change legislation or regulations could have on our business, we believe we will face a lower compliance burden than some of our competitors due to the relatively low GHG emission rates of our fleet. We continue to monitor and actively participate in the processes where we anticipate an impact on our business.

Further, as a result of air regulations recently enacted in New Jersey, certain of our generation assets acquired in the Conectiv Acquisition may need additional NO_X controls to continue operating beyond 2015, which may result in additional controls costs to us. The cost of such future controls is uncertain at this time; however, they are not expected to be material or adversely impact our results of operations.

We are subject to other complex governmental regulation which could adversely affect our operations.

Generally, in the U.S., we are subject to regulation by FERC regarding the terms and conditions of wholesale service and the sale and transportation of natural gas, as well as by state agencies regarding physical aspects of the power plants. The majority of our generation is sold at market prices under the market-based rate authority granted by the FERC. If certain conditions are not met, FERC has the authority to withhold or rescind market-based rate authority and require sales to be made based on cost-of-service rates. A loss of our market-based rate authority could have a materially negative impact on our generation business. FERC could also impose fines or other restrictions or requirements on us under certain circumstances.

The construction and operation of power plants require numerous permits, approvals and certificates from the appropriate foreign, federal, state and local governmental agencies, as well as compliance with numerous environmental laws and regulations of federal, state and local authorities. Should we fail to comply with any environmental requirements that apply to power plant construction or operations, we could be subject to administrative, civil and/or criminal liability and fines, and regulatory agencies could take other actions to curtail our operations.

Furthermore, certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. We are generally responsible for all liabilities associated with the environmental condition of our power plants, including any soil or groundwater contamination that may be present, regardless of when the liabilities arose and whether the liabilities are known or unknown, or arose from the activities of predecessors or third parties.

If we were deemed to have market power in certain markets as a result of the ownership of our stock by certain significant shareholders, we could lose FERC authorization to sell power at wholesale at market-based rates in such markets or be required to engage in mitigation in those markets.

Certain of our significant shareholder groups own power generating assets, or own significant equity interests in entities with power generating assets, in markets where we currently own power plants. We could be determined to have market power if these existing significant shareholders acquire additional significant ownership or equity interest in other entities with power generating assets in the same markets where we generate and sell power.

If FERC makes the determination that we have market power, FERC could, among other things, revoke market-based rate authority for the affected market-based companies or order them to mitigate that market power. If market-based rate authority were revoked for any of our market-based rate companies, those companies would be required to make wholesale sales of power based on cost-of-service rates, which could negatively impact their revenues. If we are required to mitigate market power, we could be required to sell certain power plants in regions where we are determined to have market power. A loss of our market-based rate authority or required sales of power plants, particularly if it affected several of our power plants or was in a significant market such as California, could have a material negative impact on our financial condition, results of operations and cash flows.

Risks Relating to Our Common Stock

Our principal shareholders own a significant amount of our common stock, giving them influence over corporate transactions and other matters.

As of December 31, 2010, three current holders (or related groups of holders) of our common stock have made filings with the SEC reporting beneficial ownership, directly or indirectly, individually or as members of a group, of 5% or more of the shares of our common stock. These shareholders, who together beneficially owned approximately 46% of our common stock at December 31, 2010, may be able to exercise substantial influence over all matters requiring shareholder approval, including the election of directors and approval of significant corporate action, such as mergers and other business combination transactions. If two or more of these shareholders (or groups of shareholders) vote their shares in the same manner, their combined stock ownership may effectively give significant influence over the election of our entire Board of Directors and significant influence over our management, operations and affairs. Currently, two members of our Board of Directors, including the Chairman of our Board, are affiliated, directly or indirectly, with SPO Advisory Corp., one of these shareholders.

Circumstances may occur in which the interests of these shareholders could be in conflict with the interests of other shareholders. This concentration of ownership may also have the effect of delaying or preventing a change in control over us unless it is supported by these shareholders. Accordingly, the ability of our other shareholders to influence us through voting of their shares may be limited or the market price of our common stock may be adversely affected. Additionally, we have filed a registration statement on Form S-3 registering the resale of the common stock held by certain members of one of the three groups of these shareholders, which permits them to sell a large portion of their shares of common stock without being subject to the "trickle out" or other restrictions of Rule 144 under the Securities Act. There were no sales during 2010 by shareholders who held more than 5% of our common stock. Sales by the three shareholders of all or a substantial portion of their shares within a short period of time, could adversely affect the market price of our common stock or could further concentrate holdings of our common stock in the remaining two shareholders who hold more than 5% of our common stock.

Transfers of our equity, or issuances of equity, may impair our ability to utilize our federal income tax NOL carryforwards in the future.

Under federal income tax law, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of the IRC. We experienced an ownership change on the Effective Date as a result of the cancellation of our old common stock and the distribution of our new common stock pursuant to our Plan of Reorganization. However, this ownership change and resulting annual limitations are not expected to result in the expiration of our NOL carryforwards if we are able to generate sufficient future taxable income within the carryforward periods. If a subsequent ownership change were to occur as a result of future transactions in our stock, accompanied by a significant reduction in our market value immediately prior to the ownership change, our ability to utilize the NOL carryforwards may be significantly limited.

To manage the risk of significant limitations on our ability to utilize our tax NOL carryforwards, our amended and restated certificate of incorporation permits our Board of Directors to meet to determine whether to impose certain transfer restrictions on our common stock if, prior to February 1, 2013, our Market Capitalization declines by at least 35% from our Emergence Date Market Capitalization of approximately $8.6 billion (in each case, as defined in and calculated pursuant to our amended and restated certificate of incorporation) and at least 25 percentage points of shift in ownership has occurred with respect to our equity for purposes of Section 382 of the IRC. We believe, as of the filing of this Report, neither circumstance was met. While we don't believe an ownership change of 25 percentage points has occurred, the change in ownership is only slightly less than 25%. Accordingly, the transfer restrictions have not been put in place by our Board of Directors; however, if both of the foregoing events were to occur together and our Board of Directors were to elect to impose them, they could become operative in the future. There can be no assurance that the circumstances will not be met in the future, or in the event that they are met, that our Board of Directors would choose to impose these restrictions or that, if imposed, such restrictions would prevent an ownership change from occurring.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Our principal executive offices are located in Houston, Texas. This facility is leased until 2020. We also have regional offices in Dublin, California and Wilmington, Delaware, an engineering, construction and maintenance services office in Pasadena, Texas and government affairs offices in Washington D.C., Sacramento, California and Austin, Texas.

We either lease or own the land upon which our power plants are built. We believe that our properties are adequate for our current operations. A description of our power plants is included under Item 1. "Business — Description of Our Power Plants."

Item 3. ***Legal Proceedings***

See Note 15 of the Notes to Consolidated Financial Statements for a description of our legal proceedings.

Item 4. ***(Reserved)***

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information and Stockholder Matters

On January 31, 2008, pursuant to our Plan of Reorganization, our previously outstanding common stock was canceled, and we authorized and began issuance of 485 million shares of reorganized Calpine Corporation common stock to settle unsecured claims pursuant to our Plan of Reorganization. On January 16, 2008, the shares of reorganized Calpine Corporation common stock were admitted to listing on the NYSE and began "when issued" trading under the symbol "CPN-WI." The reorganized Calpine Corporation common stock began "regular way" trading on the NYSE under the symbol "CPN" on February 7, 2008.

The following table sets forth the high and low bid prices for our common stock for each quarter of the calendar years 2010 and 2009, as reported on the NYSE.

	High	Low
2010		
First Quarter	$ 12.42	$ 10.71
Second Quarter	14.27	10.95
Third Quarter	14.13	12.20
Fourth Quarter	13.93	11.88
2009		
First Quarter	$ 9.34	$ 4.76
Second Quarter	14.95	6.64
Third Quarter	13.75	10.10
Fourth Quarter	12.25	10.14

As of December 31, 2010, there were 98 stockholders of record of our common stock. See Note 18 of the Notes to Consolidated Financial Statements for a discussion of the effects of emergence from Chapter 11 on our capital structure.

To manage the risk of significant limitations on our ability to utilize our tax NOL carryforwards, our amended and restated certificate of incorporation permits our Board of Directors to meet to determine whether to impose certain transfer restrictions on our common stock if, prior to February 1, 2013, our Market Capitalization declines by at least 35% from our Emergence Date Market Capitalization of approximately $8.6 billion (in each case as defined and calculated pursuant to our amended and restated certificate of incorporation) and at least 25 percentage points of shift in ownership has occurred with respect to our equity for purposes of Section 382 of the IRC. As of the filing of this Report, neither circumstance was met. While we don't believe an ownership change of 25 percentage points has occurred, the change in ownership is only slightly less than 25%. Accordingly, the transfer restrictions have not been put in place by our Board of Directors; however, if both of the foregoing events were to occur together and our Board of Directors were to elect to impose them, they could become operative in the future. There can be no assurance that the circumstances will not be met in the future, or in the event that they are met, that our Board of Directors would choose to impose these restrictions or that, if imposed, such restrictions would prevent an ownership change from occurring.

Should our Board of Directors elect to impose these restrictions, they shall have the authority and discretion to determine and establish the definitive terms of the transfer restrictions provided that they apply to purchases by owners of 5% or more of our common stock including any owners who would become owners of 5% or more of our common stock via such purchase. The transfer restrictions will not apply to the disposition of shares provided they are not purchased by a 5% or more owner. If these transfer restrictions are imposed, any increase in the value of our common stock shall not result in the lapse of the transfer restrictions unless the increase in value of our common stock (determined on a weighted average 30-day trading period) shall be at least 10% greater than the trigger price. Our Board of Directors' ability to impose transfer restrictions will terminate on the fifth anniversary of our Emergence Date; however, any transfer restrictions imposed prior to such fifth anniversary will remain in effect until one of the trigger provisions is no longer satisfied.

We have never paid cash dividends on our common stock. 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 and financing restrictions and such other factors as our Board of Directors may deem relevant. See Item 1A. "Risk Factors," including "— Risks Relating to Our Common Stock" for a discussion of additional risks related to an investment in our common stock.

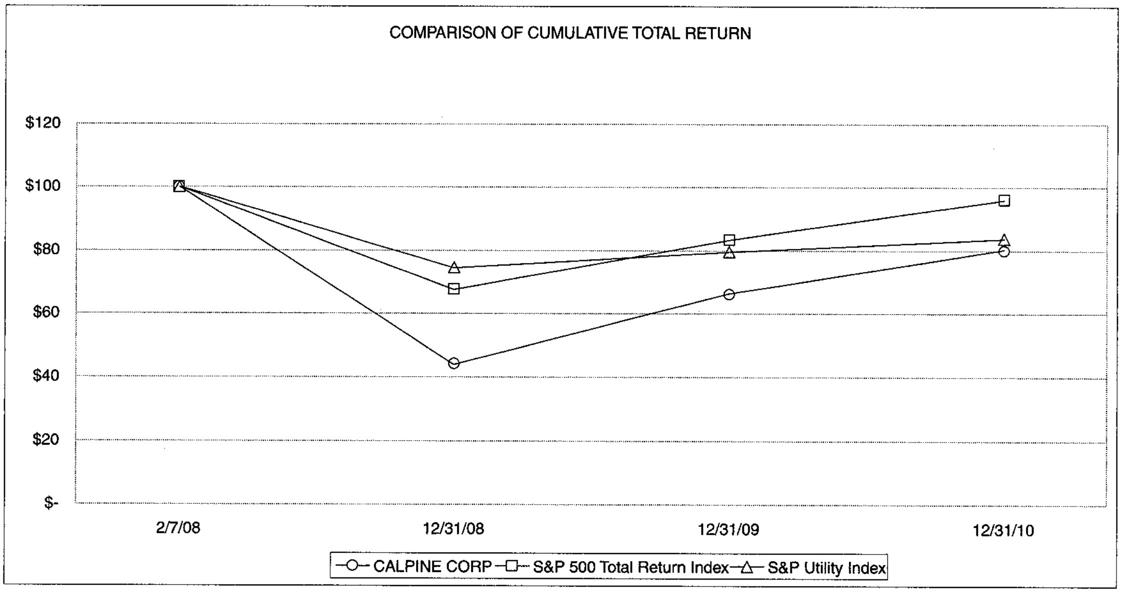
Repurchase of Equity Securities — Upon vesting of restricted stock awarded by us to employees, we withhold shares to cover employees' tax withholding obligations, other than for employees who have chosen to make tax withholding payments in cash. We withheld a total of 120,586 shares during 2010 that are included in treasury stock. We do not have a stock repurchase program. As set forth in the table below, we withheld 240 shares during the fourth quarter of 2010.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs
November	100	$ 12.44	—	n/a
December	140	$ 12.46	—	n/a
Total	240	$ 12.45	—	n/a

Stock Performance Graph

The performance graph below compares cumulative return on our common stock for the period February 7, 2008 through December 31, 2010, with the cumulative return of Standard & Poor's 500 Index (S&P 500) and the S&P 500 Utility Index. Since the reorganized Calpine Corporation common stock began "regular way" trading on the NYSE on February 7, 2008, stock performance prior to February 7, 2008 does not provide meaningful comparison and has not been provided.

The graph below compares each period assuming that $100 was invested on February 7, 2008 in our common stock and each of above indices and that all dividends are reinvested. The returns shown below may not be indicative of future performance.



Company / Index	February 7, 2008	December 31, 2008	December 31, 2009	December 31, 2010
Calpine Corporation	$ 100	$ 43.86	$ 66.27	$ 80.36
S&P 500 Index	100	67.56	83.41	95.97
S&P Utility Index	100	74.38	79.44	83.77

Item 6. *Selected Financial Data*

SELECTED CONSOLIDATED FINANCIAL DATA

	Years Ended December 31,				
	2010	2009	2008	2007	2006
	(in millions, except earnings (loss) per share)				
Statement of Operations data:					
Operating revenues	$ 6,545	$ 6,463	$ 9,837	$ 7,869	$ 6,843
Income (loss) before discontinued operations attributable to Calpine[1]	$ (162)	$ 114	$ (26)	$ 2,666	$ (1,773)
Discontinued operations, net of tax expense, attributable to Calpine	193	35	36	27	8
Net income (loss) attributable to Calpine[1]	$ 31	$ 149	$ 10	$ 2,693	$ (1,765)
Basic earnings (loss) per common share[2]:					
Income (loss) before discontinued operations attributable to Calpine[1]	$ (0.33)	$ 0.24	$ (0.05)	$ 5.56	$ (3.70)
Discontinued operations, net of tax expense, attributable to Calpine	0.39	0.07	0.07	0.06	0.02
Net income (loss) per common share attributable to Calpine[1]	$ 0.06	$ 0.31	$ 0.02	$ 5.62	$ (3.68)
Diluted earnings (loss) per common share[2]:					
Income (loss) before discontinued operations attributable to Calpine[1]	$ (0.33)	$ 0.24	$ (0.05)	$ 5.56	$ (3.70)
Discontinued operations, net of tax expense, attributable to Calpine	0.39	0.07	0.07	0.06	0.02
Net income (loss) per common share attributable to Calpine[1]	$ 0.06	$ 0.31	$ 0.02	$ 5.62	$ (3.68)
Balance Sheet data:					
Total assets	$ 17,256	$ 16,650	$ 20,738	$ 19,050	$ 18,590
Short-term debt and capital lease obligations[3]	152	463	716	1,710	4,569
Long-term debt and capital lease obligations[3][4]	10,104	8,996	9,756	9,946	3,352
Liabilities subject to compromise[4]	—	—	—	8,788	14,757

(1) During 2007, we were released from a portion of our direct and indirect Canadian guarantee of the ULC I notes, ULC II notes and redundant Canadian claims and recorded a $4.1 billion credit for the reversal of these redundant claims.

(2) Although earnings (loss) per share information for the years ended December 31, 2007 and 2006 is presented, it is not comparable to the information presented for the years ended December 31, 2010, 2009 and 2008, due to the changes in our capital structure on the Effective Date, which also included termination of all outstanding convertible securities.

(3) As a result of our Chapter 11 filings, we reclassified approximately $5.1 billion of long-term debt and capital lease obligations to short-term at December 31, 2006, as our Chapter 11 filings constituted events of default or otherwise triggered repayment obligations for the Calpine Debtors and certain Non-Debtor entities. We classified our long-term debt and capital lease obligations at December 31, 2007, based upon the refinanced terms of our First Lien Facilities.

(4) LSTC included unsecured and under secured liabilities incurred prior to the Petition Date and excluded liabilities that are fully secured or liabilities of our subsidiaries or affiliates that did not make Chapter 11 filings and other approved payments such as taxes and payroll. We reclassified $3.7 billion from LSTC to long-term debt based upon the terms of our Plan of Reorganization at December 31, 2007.

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

Forward-Looking Information

This Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our accompanying Consolidated Financial Statements and related notes. See the cautionary statement regarding forward-looking statements on page 1 of this Report for a description of important factors that could cause actual results to differ from expected results. See also Item 1A. "Risk Factors."

INTRODUCTION AND OVERVIEW

Our Business

We are the largest independent wholesale power company in the U.S. measured by power produced. We own and operate natural gas-fired and geothermal power plants in North America and have a significant presence in major competitive wholesale power markets in California, Texas and the Mid-Atlantic region of the U.S. We sell wholesale power, steam, regulatory capacity, renewable energy credits and ancillary services to our customers, including utilities, independent electric system operators, industrial and agricultural companies, retail power providers, municipalities, power marketers and others. We have invested in clean power generation to become a recognized leader in developing, constructing, owning and operating an environmentally responsible portfolio of power plants. We purchase natural gas and fuel oil as fuel for our power plants, engage in related natural gas transportation and storage transactions, and we purchase electric transmission rights to deliver power to our customers. We also enter into natural gas and power-related commodity and derivative transactions to financially hedge certain business risks and optimize our portfolio of power plants. Our goal is to be recognized as the premier independent power company in the U.S. as measured by our customers, regulators, shareholders and communities in which our power plants are located. We seek to achieve sustainable growth through financially disciplined power plant development, construction acquisition, operation and ownership. We will continue to pursue opportunities to improve our fleet performance and reduce operating costs. In order to manage our various physical assets and contractual obligations, we will continue to execute commodity hedging agreements within the guidelines of our commodity risk policy.

As part of our initiative to deploy our capital in the most advantageous way for our shareholders, the Conectiv Acquisition on July 1, 2010, provided us with a significant presence in the Mid-Atlantic region of the U.S., one of the most robust competitive power markets in the U.S., and positioned us with three scale markets instead of two (California and Texas) giving us greater geographical diversity. We added 18 operating power plants and one plant under construction, with approximately 4,490 MW of capacity (including completion of the York Energy Center under construction and scheduled upgrades). Approximately 340 MW of the plants acquired have conventional steam turbine technology where coal was used as the primary fuel source prior to our acquisition of them. These power plants are also capable of burning natural gas or fuel oil to generate power. At the close of this acquisition, under our environmental leadership, these plants ceased burning coal and we do not intend to burn coal to generate power from these power plants in the future. Instead, we generate power from these power plants using natural gas and plan to modernize these sites in the longer term to more efficient natural gas-fired combustion turbines.

We assess our business on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and other factors impacting supply and demand. Our reportable segments are West (including geothermal), Texas, North (including Canada) and Southeast. The generation assets we acquired in the Conectiv Acquisition are reported in our North segment.

Our portfolio, including partnership interests, includes 91 operating power plants, located throughout 20 states in the U.S. and Canada, with an aggregate generation capacity of 27,490 MW and 1,149 MW under construction. Our generation capacity includes approximately 5,241 MW of baseload capacity from our Geysers Assets and cogeneration power plants, 15,838 MW of intermediate load capacity from our combined-cycle combustion turbines and 6,411 MW of peaking capacity from our simple-cycle combustion turbines, duct-fired capability and approximately 4 MW of capacity from solar, photovoltaic power generation technology located in New Jersey and included in our North segment. Our segments have an aggregate generation capacity of 6,886 MW with an additional 584 MW under construction in the West, 7,185 MW in Texas, 7,336 MW with an additional 565 MW under construction in the North and 6,083 MW in the Southeast. Our Geysers Assets, included in our West segment, have generation capacity of approximately 725 MW from 15 operating geothermal power plants and we have begun expansion efforts to increase our generation capacity at our Geysers Assets.

Current Year Operational Developments

During 2010 and through the filing of this Report, we have continued to implement our strategy. We have made some notable achievements that are listed below:

- As discussed above, we completed the Conectiv Acquisition on July 1, 2010.

- All permits have been received and COD is expected in March 2011 for our York Energy Center, three months early and approximately $20 million under budget. The York Energy Center will sell power under a six-year PPA with a third party.

- We received all required approvals and permits, subject to on-going judicial appeals, for our Russell City Energy Center, which continues to move forward. We began construction in 2010, and we are in the process of obtaining project financing. The expected COD is in 2013. Upon completion, this project will bring on line approximately 429 MW of net interest baseload capacity (464 MW with peaking capacity) representing our expected 75% share.

- We received all required approvals and permits to begin construction to upgrade our Los Esteros Critical Energy Facility from a 188 MW simple-cycle generation power plant to a 308 MW combined-cycle generation power plant, which will also increase the efficiency and environmental performance of the power plant by lowering the Heat Rate. The California Energy Commission has renewed our license and emission limits, but the appeal period has not yet expired. We are in the process of procuring equipment and selecting the engineering, procurement and construction contractors. We expect COD during the third quarter of 2013.

- We continue to move forward with our turbine upgrade program and have entered into an agreement to upgrade select GE and Siemens turbines. Through January 2011, we have completed the upgrade of six Siemens turbines and have agreed to upgrade approximately 15 additional Siemens and GE turbines (and may upgrade additional turbines in the future). Our turbine upgrade program is expected to increase our generation capacity in total by approximately 275 MW. This upgrade program began in the fourth quarter of 2009 and is scheduled through 2014. The upgraded turbines have been operating with Heat Rates falling in line with expectations.

- We continue to look to expand our production from our Geysers Assets. Beginning in the fourth quarter of 2009, we conducted an exploratory drilling program, which effectively proved the commercial viability of the steam field in the northern part of our Geysers Assets; however, permitting challenges have emerged that we are working our way through. We were planning to target a 2013 COD for an expansion of our Geysers Assets and had been, in parallel, negotiating commercial arrangements to support that, but the permitting delay has increased the risk we will not meet a target 2013 COD. We continue to believe our northern Geysers Assets have potential for development. In the near term, we will work to connect the test wells we have drilled over the last year to our existing power plants and will work to capture incremental MW from those wells, while continuing with the permitting process, baseline engineering work and sales efforts for an expansion target COD subsequent to 2013.

- Throughout 2010, our plant operating personnel exceeded the first quartile performance for employee lost time incident rate for fossil fuel electric power generation companies with 1,000 or more employees.

- Our Geysers Assets generated approximately 6 million MWh and achieved an exceptional availability factor of over 98%. Our natural gas-fired fleet achieved a forced outage factor of 3.1%.

- We completed 15 major inspections and 12 hot gas path inspections during 2010, and, through January 2011.

Enhancing Shareholder Value

In addition to the above, we have opportunistically completed significant financing transactions that have improved our capital structure and financial flexibility, and strengthened our balance sheet. Our efforts have delivered significant results.

- The most significant of our 2010 and early 2011 financing transactions was the issuance of the First Lien Notes, termination of the First Lien Credit Facility and extension of our debt maturities. Beginning in the fourth quarter of 2009 and through January of 2011, we issued First Lien Notes in a series of tranches with maturity dates in 2017, 2019, 2020, 2021 and 2023. The proceeds from those issuances, together with operating cash, were used to fully repay all of our outstanding term loan borrowings under our First Lien Credit Facility, thereby terminating the First Lien Credit Facility in accordance with its terms. The termination of the First Lien Credit Facility eliminated the more restrictive of our debt covenants, resulting in increased operational, strategic and financial flexibility in managing our capital resources including the flexibility to reinvest more earnings for organic growth, issue and/or buyback shares of our common stock, pay dividends and incur additional debt, if needed, for acquisitions or development. Additionally, we significantly smoothed and extended contractual debt maturities of approximately $4.7 billion (as of December 31, 2009) due in 2014, such that no more than $2.0 billion of our corporate debt matures in any one year.

- On December 10, 2010, we executed our $1.0 billion Corporate Revolving Facility, which replaced our $1.0 billion revolver under our First Lien Credit Facility and allows for up to $750 million of availability for the issuance of letters of credit and up to $50 million as a swingline subfacility. The Corporate Revolving Facility may be utilized for working capital requirements and other general corporate purposes.

- Our Conectiv Acquisition added $1.64 billion in net assets with $1.3 billion in project debt. The remaining amounts were funded with operating cash on hand.

- We sold 100% of our ownership interests in Blue Spruce and Rocky Mountain for approximately $739 million, resulting in a pre-tax gain of approximately $209 million. The sales proceeds received were used to repay $418 million in project debt and the remaining funds will be used to fund future development and growth in our core markets.

- We sold a 25% undivided interest in the assets of our Freestone power plant for approximately $215 million in cash. We recorded a pre-tax gain of approximately $119 million for the year ended December 31, 2010, which is included in gain on sale of assets on our Consolidated Statement of Operations. The sales proceeds received will be used to fund future development and growth in our core markets.

For a further discussion of our significant financing transactions completed in 2010 and early 2011 through the filing of this Report, see "— Liquidity and Capital Resources."

Customer-Oriented Origination Business

We reorganized our customer origination function to allow a dedicated group of professionals to more effectively manage our forward power sales. Their charter is to understand our customers' wants and needs and to rally our organization to develop unique, cost-effective solutions that benefit us and our customers. This effort has delivered real, tangible results.

- We received approval of our PPA contracts totaling 1,250 MW with SDG&E and PG&E from the CPUC.
- We have entered into a new seven-year PPA with Xcel Energy to provide 200 MW of power generated by our Oneta Energy Center to Southwestern Public Service Company, a subsidiary of Xcel Energy.
- We sold 100% of our ownership interests in Blue Spruce and Rocky Mountain and a 25% undivided interest in the assets of our Freestone power plant as described above.
- We have entered into a PPA with Bonneville Power Administration to provide up to 75 MW of wind power generation flexibility.

The last transaction is an indication of the growing need our customers, and more generally the market, have to utilize flexible natural gas-fired generation to integrate into the grid supply from intermittent and variable renewable resources, such as wind and solar power, that they are required to procure as part of a renewable energy portfolio, while assuring reliability.

Our Regulatory and Environmental Profile

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 power plants. Federal and state legislative and regulatory actions continue to change how our business is regulated. The federal government is expected to take action on climate change regulation, as well as other air pollutant emissions, and many states and regions in the U.S. have implemented or are considering implementing regulations to reduce GHG emissions. We are actively participating in these debates at the federal, regional and state levels. For a further discussion of the environmental and other governmental regulations that affect us, see "— Governmental and Regulatory Matters" in Item 1. of this Report. Although we cannot predict the ultimate effect future climate change regulations or legislation could have on our business, we believe that we will be less adversely impacted by potential cap-and-trade limits, carbon taxes or required environmental upgrades as a result of future potential regulation or legislation addressing GHG, other air emissions, as well as water use or emissions, than compared to our competitors who use other fossil fuels or steam condensation technologies.

Since our inception in 1984, we have been a leader in environmental stewardship and have invested in clean power generation to become a recognized leader in developing, constructing, owning and operating an environmentally responsible portfolio of power plants. The combination of our Geysers Assets and our high efficiency portfolio of natural gas-fired power plants results in substantially lower emissions of these gases compared to our competitors' power plants using other fossil fuels, such as coal. Consequently, our power generation portfolio has the lowest GHG footprint per MWh of any major independent power producer in the U.S. In addition, we strive to preserve our nation's valuable water and land resources. To condense steam, we primarily use cooling towers with a closed water cooling system, or air cooled condensers. Since our plants are modern and efficient and utilize clean burning natural gas, we do not require large areas of land for our power plants nor do we require large specialized landfills for the disposal of coal ash or nuclear plant waste.

Our Market and Our Key Financial Performance Drivers

The market Spark Spread, sales of RECs, revenues from our steam sales and the results from our marketing, hedging and optimization activities are the primary components of our Commodity Margin and contribute significantly to our financial results. The market Spark Spread is primarily impacted by natural gas prices, weather and reserve margins, which impact both our supply and demand fundamentals. Those factors, plus the relationship between our operating Heat Rate compared to the Market Heat Rate, our power plant operating performance and availability are key to our financial performance.

Depending upon our hedge levels and holding other factors constant, increases in natural gas prices tend to increase our Commodity Margin and decreases in natural gas prices tend to decrease our Commodity Margin because we generally have lower Heat Rates and are more efficient than our competitors. Efficient operation of our fleet creates the opportunity to capture Commodity Margin in a cost effective manner. However, unplanned outages during periods when Commodity Margin is positive could result in a loss of that opportunity. We generally measure our fleet performance based on our availability factors, Heat Rate and plant operating expense. The higher our availability factor, the better positioned we are to capture Commodity Margin. The less natural gas we must consume for each MWh of power generated, the lower our Heat Rate. The lower our operating Heat Rate compared to the Market Heat Rate, the more favorable the impact on our Commodity Margin. Holding all other factors constant, our Commodity Margin increases when we are able to lower our operating Heat Rate compared to the Market Heat Rate and conversely decreases when our operating Heat Rate increases compared to the Market Heat Rate. See also "— The Market for Power — Our Power Market Economics" in Item 1. of this Report for additional information on how these factors impact our Commodity Margin.

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2010 AND 2009

Below are our results of operations for the year ended December 31, 2010, as compared to the same period in 2009 (in millions, except for percentages and operating performance metrics). In the comparative tables below, increases in revenue/income or decreases in expense (favorable variances) are shown without brackets while decreases in revenue/income or increases in expense (unfavorable variances) are shown with brackets.

	2010	2009	Change	% Change
Operating revenues:				
Commodity revenue	$ 6,578	$ 6,362	$ 216	3%
Mark-to-market activity[1]	(61)	80	(141)	#
Other revenue	28	21	7	33
Operating revenues	6,545	6,463	82	1
Cost of revenue:				
Fuel and purchased energy expense:				
Commodity expense	4,178	3,896	(282)	(7)
Mark-to-market activity[1]	(204)	1	205	#
Fuel and purchased energy expense	3,974	3,897	(77)	(2)
Plant operating expense	868	868	—	—
Depreciation and amortization expense	570	456	(114)	(25)
Sales, general and other administrative expense	151	174	23	13
Other operating expense[2]	100	101	1	1
Total operating expenses	5,663	5,496	(167)	(3)
Impairment losses	116	4	(112)	#
(Gain) on sale of assets, net	(119)	—	119	—
(Income) from unconsolidated investments in power plants	(16)	(50)	(34)	(68)
Income from operations	901	1,013	(112)	(11)
Interest expense	789	815	26	3
(Gain) loss on interest rate derivatives, net	247	—	(247)	—
Interest (income)	(11)	(16)	(5)	(31)
Debt extinguishment costs	91	76	(15)	(20)
Other (income) expense, net	15	14	(1)	(7)
Income (loss) before reorganization items, income taxes and discontinued operations	(230)	124	(354)	#
Reorganization items	—	(1)	(1)	#
Income (loss) before income taxes and discontinued operations	(230)	125	(355)	#
Income tax expense (benefit)	(68)	15	83	#
Income (loss) before discontinued operations	(162)	110	(272)	#
Discontinued operations, net of tax expense	193	35	158	#
Net income	31	145	(114)	(79)
Net loss attributable to the noncontrolling interest	—	4	(4)	#
Net income attributable to Calpine	$ 31	$ 149	$ (118)	(79)

	2010	2009	Change	% Change
Operating Performance Metrics:				
MWh generated (in thousands)[3]	88,323	84,376	3,947	5%
Average availability	90.4%	92.1%	(1.7)	(2)
Average total MW in operation[3]	24,993	22,483	2,510	11
Average capacity factor, excluding peakers	46.0%	48.2%	(2.2)	(5)
Steam Adjusted Heat Rate	7,338	7,264	(74)	(1)

\# Variance of 100% or greater

(1) Amount represents the unrealized portion of our mark-to-market activity.

(2) Includes $9 million and $5 million of RGGI compliance and other environmental costs for the years ended December 31, 2010 and 2009, respectively, which are components of Commodity Margin.

(3) Represents generation and capacity from power plants that we both consolidate and operate. See "— Description of Our Power Plants – Table of Operating Power Plants and Projects Under Construction" for our total equity generation and capacities.

We evaluate our commodity revenue and commodity expense on a collective basis because the price of power and natural gas move together as the price for power is generally determined by the variable operating cost of the next marginal generator to be dispatched to meet demand. The spread between our commodity revenue and commodity expense represents a significant portion of our Commodity Margin. Our financial performance is correlated to how we maximize our Commodity Margin through management of our portfolio of power plants, as well as our hedging and optimization activities. See additional segment discussion in "Commodity Margin and Adjusted EBITDA."

Commodity revenue, net of commodity expense, decreased $66 million for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily due to:

- lower average hedge margins in 2010 compared to 2009;
- lower realized Spark Spreads on open positions due to lower Market Heat Rates, primarily in California and Texas, attributable to weaker market conditions resulting from milder weather and increased hydroelectric generation in the West and an increase in installed generation capacity in California and Texas in 2010 compared to 2009; partially offset by
- an increase in the North primarily due to the Conectiv Acquisition which closed on July 1, 2010.

Our average total MW in operation increased by 2,510 MW, or 11%, primarily due to the Conectiv Acquisition and OMEC, which achieved commercial operations in October 2009 and was consolidated on January 1, 2010. Generation increased 5% due primarily to the Conectiv Acquisition and stronger market price conditions in the North partially offset by weaker market price conditions in California and Texas.

Unrealized mark-to-market earnings from hedging our future generation and fuel needs increased by $64 million primarily driven by the impact of lower gas prices on our forward short financial gas position partially offset by losses recognized on our short power Heat Rate swap position held at December 31, 2010.

Other revenue increased for the year ended December 31, 2010 compared to the year ended December 31, 2009, due primarily to $19 million in revenue recognized in 2010 which included a $15 million adjustment related to prior periods on a maintenance contract. This increase was partially offset by a decrease of $8 million related to an operations and maintenance contract that expired in March 2010.

Plant operating expense was unchanged for the year ended December 31, 2010 compared to the year ended December 31, 2009, despite a 2,510 MW increase in our average total MW in operation over the same periods. During 2010 compared to 2009, we experienced a decrease of $28 million in normal, recurring plant operating expense, a decrease of $22 million in costs from scrap parts related to outages, a $16 million decrease in major maintenance resulting from our plant outage schedule and a decrease of $6 million in stock-based compensation expense related to plant personnel costs. The decrease in plant operating expense was offset by an increase related to the Conectiv Acquisition, and OMEC, which achieved commercial operations in October 2009 and was consolidated on January 1, 2010, and a $6 million increase related to costs incurred for unscheduled outages.

Depreciation and amortization expense increased for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily resulting from an increase of $68 million due to a revision in the estimated useful lives and salvage values of our power plants and related equipment and changing our Geysers Assets depreciation from the units of production method to the straight line method. See Note 4 of the Notes to Consolidated Financial Statements for further information regarding our change in useful lives and salvage values as well as our change from the units of production method to the straight line depreciation method for our Geysers Assets. Also contributing to the increase was $33 million in depreciation and amortization expense related to the Conectiv Acquisition and $15 million related to OMEC which achieved commercial operation in October 2009 and was consolidated on January 1, 2010.

Sales, general and other administrative expense decreased for the year ended December 31, 2010 compared to the year December 31, 2009, due to a $21 million decrease in personnel costs due largely to lower stock-based compensation expense and temporary labor costs, a $14 million favorable change in our bad debt expense primarily related to a $10 million reversal of our bad debt allowance in the first quarter of 2010 as a result of Lyondell Chemical Co.'s emergence from Chapter 11 bankruptcy and the bankruptcy court's acceptance of our claim and a $13 million decrease in consulting expense. The decrease was partially offset by $26 million in Conectiv acquisition-related costs incurred during the year ended December 31, 2010.

Impairment losses for the year ended December 31, 2010 consisted of an impairment of approximately $95 million related to South Point (see Note 3 of the Notes to Consolidated Financial Statements for further information related to our acquisition impairment of the South Point lease) and development costs of approximately $21 million associated with two development projects that originated prior to our Chapter 11 bankruptcy proceedings.

Gain on sale of assets, net consists of a $119 million gain recorded in the fourth quarter of 2010 related to the sale of a 25% undivided interest in the assets of our Freestone power plant. See Note 3 of the Notes to Consolidated Financial Statements for further information.

Income from unconsolidated investments in power plants decreased by $34 million for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily due to the consolidation of OMEC on January 1, 2010. During the year ended December 31, 2009, OMEC recorded income of $32 million which largely consisted of a $28 million gain related to mark-to-market activity from interest rate swap contracts. See Notes 2 and 5 of the Notes to Consolidated Financial Statements for further information regarding our consolidation of OMEC and unconsolidated investments, respectively.

Interest expense decreased for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily due a decrease of $26 million resulting from the repayment in February 2010 of the notes related to PCF and PCF III, a decrease of $17 million related to the refinancing of our CCFC Old Notes, CCFC Term Loans, and the CCFCP Preferred Shares in 2009 and a decrease in the annualized effective interest rates on our consolidated debt, excluding the impacts of capitalized interest and unrealized gains (losses) on interest rate swaps, which decreased to 7.8% for the year ended December 31, 2010 from 8.0% for the year ended December 31, 2009. The decrease was partially offset by an increase of approximately $52 million in interest expense related to the NDH Project Debt incurred in the second half of 2010 and a $25 million increase related to the consolidation of OMEC on January 1, 2010.

(Gain) loss on interest rate derivatives, net was $247 million for the year ended December 31, 2010 due to the reclassification of approximately $206 million in historical unrealized losses previously deferred in AOCI related to interest rate swaps formerly hedging our First Lien Credit Facility and approximately $41 million related to realized swap settlements subsequent to the reclassification date and the changes in fair value subsequent to the de-designation date of the interest rate swaps during the year ended December 31, 2010. See Note 8 of the Notes to Consolidated Financial Statements for further discussion of our interest rate swaps formerly hedging our First Lien Credit Facility.

Interest income decreased primarily due to lower average cash balances for the year ended December 31, 2010 compared to the year ended December 31, 2009.

Debt extinguishment costs for the year ended December 31, 2010 consisted of $61 million associated with the retirement of term loans under the First Lien Credit Facility in May, July and October 2010 in connection with the issuance of the 2019, 2020 and 2021 First Lien Notes and $30 million associated with the acquisition of the Broad River lease which was accounted for as a refinancing of existing debt under U.S. GAAP. See Note 3 of the Notes to Consolidated Financial Statements for further information regarding our acquisition of the Broad River lease and Note 6 of the Notes to Consolidated Financial Statements for further information regarding the issuance of the 2019, 2020 and 2021 First Lien Notes. Debt extinguishment costs for the year ended December 30, 2009 consisted of $76 million associated with the retirement of the term loans under the First Lien Credit Facility in October 2009, the refinancing of our CCFC Old Notes and CCFC Term Loans in May and June 2009, respectively, and the CCFCP Preferred Shares that were redeemed on or before July 1, 2009.

During the year ended December 31, 2010, we recorded an income tax (benefit) of $(68) million compared to income tax expense of $15 million for the year ended December 31, 2009. The period over period change primarily resulted from a decrease of $129 million related to the application of intraperiod tax allocation partially offset by an increase in federal income tax of $43 million for the CCFC group for the year ended December 31, 2010 compared to the year ended December 31, 2009.

Income from discontinued operations increased for the year ended December 31, 2010 compared to the year ended December 31, 2009, due largely to a $160 million gain, net of tax, on the sale of our 100% ownership interests in Blue Spruce and Rocky Mountain. See Note 3 of the Notes to Consolidated Financial Statements for further discussion of our discontinued operations.

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2009 AND 2008

Below are our results of operations for the year ended December 31, 2009, as compared to the same period in 2008 (in millions, except for percentages and operating performance metrics). In the comparative tables below, increases in revenue/income or decreases in expense (favorable variances) are shown without brackets while decreases in revenue/income or increases in expense (unfavorable variances) are shown with brackets.

	2009	2008	Change	% Change
Operating revenues:				
Commodity revenue	$ 6,362	$ 9,776	$(3,414)	(35)%
Mark-to-market activity[1]	80	4	76	#
Other revenue	21	57	(36)	(63)
Operating revenues	6,463	9,837	(3,374)	(34)
Cost of revenue:				
Fuel and purchased energy expense:				
Commodity expense	3,896	7,352	3,456	47
Mark-to-market activity[1]	1	(71)	(72)	#
Fuel and purchased energy expense	3,897	7,281	3,384	46
Plant operating expense	868	890	22	2
Depreciation and amortization expense	456	428	(28)	(7)
Sales, general and other administrative expense	174	203	29	14
Other operating expense[2]	101	126	25	20
Total operating expenses	5,496	8,928	3,432	38
Impairment losses	4	46	42	91
(Income) loss from unconsolidated investments in power plants	(50)	229	279	#
Income from operations	1,013	634	379	60
Interest expense	815	1,044	229	22
Interest (income)	(16)	(46)	(30)	(65)
Debt extinguishment costs	76	6	(70)	#
Other (income) expense, net	14	15	1	7
Income (loss) before reorganization items, income taxes and discontinued operations	124	(385)	509	#
Reorganization items	(1)	(302)	(301)	#
Income (loss) before income taxes and discontinued operations	125	(83)	208	#
Income tax expense (benefit)	15	(56)	(71)	#
Income (loss) before discontinued operations	110	(27)	137	#
Discontinued operations, net of tax expense	35	36	(1)	(3)
Net income	145	9	136	#
Net loss attributable to the noncontrolling interest	4	1	3	#
Net income attributable to Calpine	$ 149	$ 10	$ 139	#

	2009	2008	Change	% Change
Operating Performance Metrics:				
MWh generated (in thousands)[3]	84,376	84,078	298	—%
Average availability	92.1%	90.3%	1.8	2
Average total MW in operation[3]	22,483	22,106	377	2
Average capacity factor, excluding peakers	48.2%	47.6%	0.6	1
Steam Adjusted Heat Rate	7,264	7,231	(33)	—

Variance of 100% or greater

(1) Amount represents the unrealized portion of our mark-to-market activity as well as a non-cash gain from amortization of prepaid power sales agreements.

(2) Includes $5 million and nil of RGGI compliance costs for the years ended December 31, 2009 and 2008, respectively, which is a component of Commodity Margin.

(3) Represents generation and capacity from power plants that we both consolidate and operate.

We evaluate our commodity revenue and commodity expense on a collective basis because the price of power and natural gas move together as the price for power is generally determined by the variable operating cost of the next marginal generator to be dispatched to meet demand. The spread between our commodity revenue and commodity expense represents a significant portion of our Commodity Margin. Our financial performance is correlated to how we maximize our Commodity Margin through management of our portfolio of power plants, as well as our hedging and optimization activities. See additional segment discussion in "Commodity Margin and Adjusted EBITDA."

Commodity revenue and commodity expense decreased for the year ended December 31, 2009 compared to 2008, largely due to lower natural gas prices which decreased 53% in 2009 compared to 2008; however, commodity revenue, net of commodity expense, increased $42 million for the year ended December 31, 2009 compared to 2008, primarily due to:

- higher average hedge margins in 2009 compared to 2008;

- average annual Market Heat Rates were relatively unchanged for the year ended December 31, 2009 compared to 2008, with the exception of our Southeast segment which experienced a 35% increase in generation in 2009 compared to 2008 largely due to higher natural gas generation displacement of coal generation in certain sub-markets in our Southeast segment caused by lower natural gas prices resulting in higher Market Heat Rates; partially offset by

- lower natural gas prices in 2009 compared to 2008 and the resulting negative impact on our open positions.

These factors were also positively impacted by our operational performance where we experienced a 2% increase in our average availability and a 1% increase in our average capacity factor, excluding peakers, for the year ended December 31, 2009 compared to 2008.

Revenues from mark-to-market activity increased for the year ended December 31, 2009 compared to 2008, which is consistent with a falling commodity price environment. Expenses from mark-to-market activity increased for the year ended December 31, 2009 compared to 2008, due to the impact of natural gas market price volatility on our natural gas hedge position for our generation portfolio.

Other revenue decreased for the year ended December 31, 2009 compared to 2008, primarily related to a $14 million decrease in revenue from operation and maintenance contracts and a $7 million decrease in revenue from construction management projects completed in 2008. Also contributing to the decrease was an $11 million decrease in other revenue related to royalty income on oil and gas producing properties.

Normal, recurring plant operating expenses decreased by $22 million for the year ended December 31, 2009 compared to 2008, after accounting for $29 million in reimbursements for insurance claims from prior periods that reduced our 2008 and, to a much lesser extent, 2009 expenses. Additionally, major maintenance costs resulting from our plant outage schedule decreased $17 million and plant personnel costs related to stock-based compensation expense decreased $8 million for the year ended December 31, 2009 compared to 2008.

Depreciation and amortization expense increased for the year ended December 31, 2009 compared to 2008, primarily resulting from an increase of $22 million in the fourth quarter of 2009 related to a revision in the estimated useful lives and salvage values of our power plants and related equipment and changing our Geysers Assets depreciation from the units of production method to the straight line method as well as a $9 million increase resulting from an upward revision in the rate used to depreciate our Geysers Assets due to changes in our estimate of our future development costs for the first nine months of 2009. See Note 4 of the Notes to Consolidated Financial Statements for further information regarding our change in useful lives and salvage values as well as our change from the units of production method to the straight line depreciation method for our Geysers Assets.

Sales, general and other administrative expense decreased for the year ended December 31, 2009 compared to 2008, due to a $10 million decrease in personnel costs and stock-based compensation expense resulting primarily from a lower headcount in 2009 as well as a $13 million decrease in legal and consulting expenses. In addition, we experienced a $5 million favorable year over year change in our bad debt expense.

Other operating expense decreased for the year ended December 31, 2009 compared to 2008, as a result of a decrease of $17 million related to the discontinuation of the amortization of other assets associated with the deconsolidation and subsequent sale of Auburndale in 2008 as well as an $11 million decrease in royalty expense due to lower revenues from our Geysers Assets resulting from lower spot market power prices in the year ended December 31, 2009 compared to 2008. The decrease was partially offset by an increase of $5 million in expenses related to RGGI compliance costs in the Northeast which was initiated in 2009.

Our impairment losses decreased for the year ended December 31, 2009 compared to 2008, primarily from a $33 million impairment recorded in 2008 relating to our Auburndale Peaking Energy Center resulting from lower forecasted future cash flows as well as impairments of $13 million recorded in 2008 related to development projects.

Our (income) loss from unconsolidated investments in power plants increased for the year ended December 31, 2009 compared to 2008, primarily due to an impairment loss of $180 million related to our equity interest in Auburndale recorded during the year ended December 31, 2008. Also contributing to the increase was income from our investment in Greenfield LP of $16 million for the year ended December 31, 2009 compared to a loss of $5 million for the year ended December 31, 2008, which is due to Greenfield LP achieving commercial operations in October 2008. We also had income of $32 million related to our investment of OMEC, of which, $4 million related to OMEC achieving commercial operation in October 2009 and a $28 million gain related to mark-to-market activities from interest rate swap contracts compared to a loss of $55 million incurred for the year ended December 31, 2008, related to unrealized mark-to-market losses from interest rate swap contracts. See Note 5 of the Notes to Consolidated Financial Statements for further information regarding our unconsolidated investments.

Due to the changes in our capital structure on the Effective Date, our interest expense for the years ended December 31, 2009 and 2008, is not directly comparable. Interest expense decreased primarily due to $135 million in post-petition interest related to pre-emergence debt recorded in the first quarter of 2008 and $27 million for settlement obligations related to the Canadian Debtors and other deconsolidated foreign entities recorded prior to their reconsolidation in February 2008. In addition, interest expense decreased for the year ended December 31, 2009 compared to 2008, due to lower average interest rates on our variable rate debt resulting from a decrease in LIBOR over the same periods. The annualized effective interest rates on our consolidated debt, excluding the impacts of capitalized interest and unrealized mark-to-market gains (losses) on interest rate swaps, after amortization of deferred financing costs and debt discounts, were 8.0% and 8.8% for the year ended December 31, 2009 and 2008, respectively. The decrease in interest expense was partially offset by the negative period over period impact of $151 million related to interest rate swap settlements resulting from a decrease in LIBOR.

Interest income decreased for the year ended December 31, 2009 compared to 2008, largely resulting from lower average interest rates earned on our cash balances which were primarily invested in U.S. Treasury securities or government-backed securities for the year ended December 31, 2009 compared to primarily invested in institutional-backed money market accounts for the year ended December 31, 2008.

Debt extinguishment costs increased for the year ended December 31, 2009 compared to 2008, primarily due to $76 million associated with the retirement of the term loans under the First Lien Credit Facility in October 2009, the refinancing of our CCFC Old Notes and CCFC Term Loans in May and June 2009 and the CCFCP Preferred Shares that were redeemed on or before July 1, 2009. This increase was partially offset by $6 million in debt extinguishment costs for the write-off of unamortized deferred financing costs associated with the refinancing of our Metcalf term loan facility and preferred interests in June 2008.

During the year ended December 31, 2009, reorganization items primarily consisted of settlements of various disputed claims. During the year ended December 31, 2008, reorganization items primarily consisted of $206 million in gains on asset sales, a $71 million gain on the reconsolidation of the Canadian Debtors and other deconsolidated foreign entities, a $62 million credit related to the settlement of claims with the Canadian Debtors and other deconsolidated foreign entities, a $34 million credit for RockGen related to a prior period which we determined was not material to any period, a $12 million credit related to the settlement with Rosetta of our fraudulent conveyance claim and $85 million in professional and trustee fees related to activity managed by our third party advisors for our Chapter 11 and CCAA cases.

For the year ended December 31, 2009, we recorded income tax expense of $15 million before discontinued operations compared to a tax (benefit) of $(56) million for the year ended December 31, 2008. Due to the valuation allowances recorded against certain deferred tax assets, our effective tax rate differs considerably from the federal statutory rate. Our tax structure is comprised primarily of two taxable groups, CCFC and its subsidiaries and Calpine Corporation and its subsidiaries other than CCFC. CCFC and its subsidiaries no longer have a valuation allowance recorded against its deferred tax assets due to its ability to generate sufficient income to utilize its NOLs. Our 2009 income tax expense primarily relates to a foreign tax expense of $2 million and $43 million expense relating to the reversal of prior year's intraperiod tax allocation due to OCI gains partially offset by a $30 million tax benefit from the CCFC group. Our 2008 benefit for income taxes before discontinued operations primarily relates to a foreign tax benefit of $70 million recorded as a result of the Canadian Settlement Agreement, and intraperiod tax allocation benefit of $99 million, which was comprised of a $76 million tax benefit to continuing operations due to current OCI gains and a $23 million tax benefit in income from discontinued operations, both of which are reflected in deferred tax benefit, offset by tax expense of approximately $100 million on CCFC's income. See Note 10 of the Notes to Consolidated Financial Statements for further information.

During the year ended December 31, 2009, we recorded $35 million in income from discontinued operations related to the results of operations of Blue Spruce and Rocky Mountain. During the year ended December 31, 2008, we recorded $36 million in income from discontinued operations, net of taxes of $23 million, related to the results of operations of Blue Spruce and Rocky Mountain as well as the settlement with Rosetta of all of our outstanding claims related to our domestic oil and gas assets we sold to Rosetta for $1.1 billion in 2005. See Note 3 of the Notes to Consolidated Financial Statements for further information related to our discontinued operations.

COMMODITY MARGIN AND ADJUSTED EBITDA

Management's Discussion and Analysis of Financial Condition and Results of Operations includes financial information prepared in accordance with U.S. GAAP, as well as the non-GAAP financial measures, Commodity Margin and Adjusted EBITDA, discussed below, which we use as a measure of our performance. Generally, a non-GAAP financial measure is a numerical measure of financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with U.S. GAAP.

We use the non-GAAP financial measure "Commodity Margin" to assess our performance by our reportable segments. Commodity Margin includes our power and steam revenues, sales of purchased power and natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, RGGI compliance and other environmental costs, and cash settlements from our marketing, hedging and optimization activities that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenues. We believe that Commodity Margin is a useful tool for assessing the performance of our core operations and is a key operational measure reviewed by our chief operating decision maker. Commodity Margin is not a measure calculated in accordance with U.S. GAAP, and should be viewed as a supplement to and not a substitute for our results of operations presented in accordance with U.S. GAAP. Commodity Margin does not intend to represent income from operations, the most comparable U.S. GAAP measure, as an indicator of operating performance and is not necessarily comparable to similarly-titled measures reported by other companies. See Note 16 of the Notes to Consolidated Financial Statements for a reconciliation of Commodity Margin to income (loss) from operations by segment.

Commodity Margin by Segment for the Years Ended December 31, 2010 and 2009

The following tables show our Commodity Margin and related operating performance metrics by segment for the years ended December 31, 2010 and 2009. In the comparative tables below, favorable variances are shown without brackets while unfavorable variances are shown with brackets. The MWh generated by segment below represents generation from power plants that we both consolidated and operate.

West:	2010	2009	Change	% Change
Commodity Margin (in millions)	$ 1,080	$ 1,245	$ (165)	(13)%
Commodity Margin per MWh generated	$ 34.94	$ 38.82	$ (3.88)	(10)
MWh generated (in thousands)	30,909	32,070	(1,161)	(4)
Average availability	91.5%	92.1%	(0.6)	(1)
Average total MW in operation	6,911	6,371	540	8
Average capacity factor, excluding peakers	56.5%	64.0%	(7.5)	(12)
Steam Adjusted Heat Rate	7,316	7,314	(2)	—

West — Commodity Margin in our West segment decreased by $165 million, or 13%, for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily resulting from a decrease of $102 million related to the expiration of the PCF arrangement in the fourth quarter of 2009, lower average hedge prices in 2010 compared to 2009, lower realized Spark Spreads on our open positions due to lower Market Heat Rates caused primarily by cooler temperatures in 2010 compared to 2009 and an overall increase in installed generation capacity as well as increased hydroelectric generation in California in 2010. Also contributing to the unfavorable period over period change was a decrease of $11 million for the sale of surplus emission allowances in the first quarter of 2009 which did not reoccur in 2010. The decrease in Commodity Margin was partially offset by an increase of $50 million related to higher REC revenue from new contracts associated with our Geysers Assets, $80 million from OMEC that achieved commercial operation in October 2009 and was consolidated on January 1, 2010 and a $12 million credit recognized in the second quarter of 2010 related to overcharges associated with a gas transportation contract. Average total MW in operation increased 540 MW, or 8%, due primarily to OMEC which was partially offset by the retirement of our Pittsburg power plant in March 2010 as well as the expiration of the operating lease and subsequent retirement of our Watsonville (Monterey) cogeneration power plant in May 2010. Our average capacity factor, excluding peakers, decreased by 12% for the year ended December 31, 2010 compared to 2009 due to the weaker price conditions in 2010 compared to 2009.

Texas:	2010	2009	Change	% Change
Commodity Margin (in millions)	$ 504	$ 644	$ (140)	(22)%
Commodity Margin per MWh generated	$ 16.71	$ 21.69	$ (4.98)	(23)
MWh generated (in thousands)	30,169	29,687	482	2
Average availability	87.6%	90.0%	(2.4)	(3)
Average total MW in operation	7,166	7,156	10	—
Average capacity factor, excluding peakers	48.1%	47.4%	0.7	1
Steam Adjusted Heat Rate	7,236	7,142	(94)	(1)

Texas — Commodity Margin in our Texas segment decreased by $140 million, or 22%, for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily resulting from lower average hedge prices and lower realized Spark Spreads on open positions due to lower Market Heat Rates, particularly with regard to June 2010, which did not benefit from the extreme heat, congestion-driven pricing and tighter reserve margin that occurred in June 2009, as well as an overall increase in installed generation capacity in ERCOT in 2010 compared to 2009. Generation increased 2% driven by higher Spark Spreads in April 2010, as well as colder weather in January and February 2010 compared to the same periods in 2009.

North:	2010	2009	Change	% Change
Commodity Margin (in millions)	$ 535	$ 268	$ 267	#%
Commodity Margin per MWh generated	$ 57.79	$ 51.06	$ 6.73	13
MWh generated (in thousands)	9,258	5,249	4,009	76
Average availability	90.7%	94.7%	(4.0)	(4)
Average total MW in operation	4,833	2,873	1,960	68
Average capacity factor, excluding peakers	32.8%	31.1%	1.7	5
Steam Adjusted Heat Rate	7,819	7,614	(205)	(3)

North — Commodity Margin in our North segment increased by $267 million primarily due to the Conectiv Acquisition which closed on July 1, 2010, higher realized Spark Spreads on open positions driven by much warmer weather in the second and third quarters of 2010 compared to the same periods in 2009, as well as colder weather in the latter fourth quarter of 2010 compared to the same period in 2009. The Conectiv Acquisition led to a 1,960 MW increase in our average total MW in operation as well as a 3,783 MWh increase in generation while stronger market pricing led to a 4% increase in generation among our legacy power plants for the year ended December 31, 2010 compared to the year ended December 31, 2009.

Southeast:	2010	2009	Change	% Change
Commodity Margin (in millions)	$ 272	$ 304	$ (32)	(11)%
Commodity Margin per MWh generated	$ 15.12	$ 17.50	$ (2.38)	(14)
MWh generated (in thousands)	17,987	17,370	617	4
Average availability	92.5%	93.2%	(0.7)	(1)
Average total MW in operation	6,083	6,083	—	—
Average capacity factor, excluding peakers	38.0%	37.9%	0.1	—
Steam Adjusted Heat Rate	7,315	7,299	(16)	—

Southeast — Commodity Margin in our Southeast segment decreased by $32 million, or 11%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. Our power plants in the Western half of the region experienced lower realized Spark Spreads on open positions, driven by lower Market Heat Rates. Partially offsetting these negative impacts, our power plants in the Eastern half of the region experienced higher realized Spark Spreads on open positions, driven by higher Market Heat Rates caused primarily by warmer weather in May and June 2010 and cooler weather in the fourth quarter of 2010 compared to the same periods in 2009. In addition, the overall decrease in Commodity Margin was partially offset by the non-recurring negative impact from the settlement of a disputed steam contract in the second quarter of 2009.

Commodity Margin by Segment for the Years Ended December 31, 2009 and 2008

The following tables show our Commodity Margin and related operating performance metrics by segment for the years ended December 31, 2009 and 2008. In the comparative tables below, favorable variances are shown without brackets while unfavorable variances are shown with brackets. The MWh generated by segment below represents generation from power plants that we both consolidated and operate.

West:	2009	2008	Change	% Change
Commodity Margin (in millions)	$ 1,245	$ 1,155	$ 90	8%
Commodity Margin per MWh generated	$ 38.82	$ 34.53	$ 4.29	12
MWh generated (in thousands)	32,070	33,453	(1,383)	(4)
Average availability	92.1%	88.2%	3.9	4
Average total MW in operation	6,371	6,364	7	—
Average capacity factor, excluding peakers	64.0%	66.5%	(2.5)	(4)
Steam Adjusted Heat Rate	7,314	7,271	(43)	(1)

West — Commodity Margin in our West segment increased by $90 million, or 8%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. The increase was primarily a result of higher hedge levels and prices, sales of surplus emission allowances in the first quarter of 2009 and higher resource adequacy and REC revenues in 2009 compared to 2008. Market Heat Rates remained relatively unchanged across periods, and lower natural gas prices resulted in lower market Spark Spreads for the year ended December 31, 2009 compared to 2008. In addition, the current period benefited from the non-recurrence in 2009 of an unfavorable natural gas storage inventory price adjustment in September 2008. Consistent with the weaker price conditions, generation decreased 4% for the year ended December 31, 2009 compared to 2008, despite a 4% increase in our average availability. Commodity Margin per MWh generated increased 12% due in part to the effect of our positive portfolio hedge value being allocated across a reduced number of generated MWh for the year ended December 31, 2009 as compared to 2008.

Texas:	2009	2008	Change	% Change
Commodity Margin (in millions)	$ 644	$ 726	$ (82)	(11)%
Commodity Margin per MWh generated	$ 21.69	$ 22.40	$ (0.71)	(3)
MWh generated (in thousands)	29,687	32,408	(2,721)	(8)
Average availability	90.0%	88.8%	1.2	1
Average total MW in operation	7,156	7,147	9	—
Average capacity factor, excluding peakers	47.4%	51.6%	(4.2)	(8)
Steam Adjusted Heat Rate	7,142	7,082	(60)	(1)

Texas — Commodity Margin in our Texas segment decreased by $82 million, or 11%, for the year ended December 31, 2009 compared to 2008. This decrease is primarily attributable to weaker natural gas prices that were 56% lower in 2009 compared to 2008. Overall, Market Heat Rates were relatively unchanged in 2009 compared to 2008; however, Market Heat Rates were higher in the third quarter of 2009 compared to the same period in 2008 due to warmer than average weather and lower in the second quarter of 2009 compared to the same period in 2008 due to the congestion-driven pricing environment of the second quarter of 2008. Also contributing to the overall decrease in Commodity Margin was lower steam sales resulting from weaker industrial demand in 2009 compared to 2008. Despite a 1% increase in average availability, generation decreased 8% on softer demand in the first half of 2009 and weaker Market Heat Rates in the second quarter of 2009. We experienced a 1% increase in our Steam Adjusted Heat Rate for the year ended December 31, 2009 compared to 2008, resulting from lower steam sales in 2009 compared to 2008.

North:

	2009	2008	Change	% Change
Commodity Margin (in millions)	$ 268	$ 279	$ (11)	(4)%
Commodity Margin per MWh generated	$ 51.06	$ 51.70	$ (0.64)	(1)
MWh generated (in thousands)	5,249	5,397	(148)	(3)
Average availability	94.7%	92.6%	2.1	2
Average total MW in operation	2,873	2,412	461	19
Average capacity factor, excluding peakers	31.1%	32.8%	(1.7)	(5)
Steam Adjusted Heat Rate	7,614	7,584	(30)	—

North — Commodity Margin in our North segment decreased by $11 million, or 4%, for the year ended December 31, 2009 compared to 2008. Although market Spark Spreads were lower in 2009 compared to 2008, the impact was largely mitigated by our hedge position as well as the favorable impact of the reconsolidation of RockGen in December 2008. In addition, despite a 2% increase in our average availability, generation decreased 3% due primarily to lower Market Heat Rates in certain sub-markets in our North segment for the year ended December 31, 2009 compared to 2008. The 461 MW, or 19%, increase in our average total MW in operation for the year ended December 31, 2009 compared to 2008, was due to the reconsolidation of RockGen in December 2008.

Southeast:

	2009	2008	Change	% Change
Commodity Margin (in millions)	$ 304	$ 264	$ 40	15%
Commodity Margin per MWh generated	$ 17.50	$ 20.59	$ (3.09)	(15)
MWh generated (in thousands)	17,370	12,820	4,550	35
Average availability	93.2%	93.6%	(0.4)	—
Average total MW in operation	6,083	6,183	(100)	(2)
Average capacity factor, excluding peakers	37.9%	26.6%	11.3	42
Steam Adjusted Heat Rate	7,299	7,388	89	1

Southeast — Commodity Margin in our Southeast segment increased by $40 million, or 15%, for the year ended December 31, 2009 compared to 2008. The increase was driven by a 35% increase in generation which resulted from higher natural gas generation displacement of coal generation in certain sub-markets in our Southeast segment primarily caused by lower natural gas prices resulting in higher Market Heat Rates in 2009 compared to 2008. Commodity Margin in the Southeast was also positively affected in 2009 compared to 2008, by the favorable impact of an off-take agreement at one of our power plants and incremental natural gas hedges. The benefit from these positive performance factors was partially offset by the negative impact from the settlement of a disputed steam contract, which adversely impacted operating revenues in 2009. In addition, a gain of $21 million related to the temporary assignment of a transmission capacity contract in the second quarter of 2008 led to a reduction in relative year over year performance. We experienced a 1% decrease in our Steam Adjusted Heat Rate in 2009 compared to 2008, resulting from increased generation. The 100 MW, or 2%, decrease in our average total MW in operation for the year ended December 31, 2009 compared to 2008, was due to the deconsolidation of Auburndale in the third quarter of 2008.

Adjusted EBITDA

We define Adjusted EBITDA as EBITDA adjusted for certain items described below and presented in the accompanying reconciliation. Adjusted EBITDA is not a measure calculated in accordance with U.S. GAAP, and should be viewed as a supplement to and not a substitute for our results of operations presented in accordance with U.S. GAAP. Our Corporate Revolving Facility and certain of our other former debt instruments, including the First Lien Credit Facility and Commodity Collateral Revolver, include a similar measure as a basis for our material covenants under those debt agreements that excludes our net interest in our unconsolidated subsidiaries and includes distributions received from unconsolidated investments. However, we believe that inclusion of our share of the Adjusted EBITDA of our unconsolidated subsidiaries is useful in evaluating our overall performance and therefore we include Adjusted EBITDA from our unconsolidated investments and exclude distributions received from our unconsolidated investments in our definition of Adjusted EBITDA. Adjusted EBITDA is not intended to represent cash flows from operations or net income (loss) as defined by U.S. GAAP as an indicator of operating performance. Furthermore, Adjusted EBITDA is not necessarily comparable to similarly-titled measures reported by other companies.

We believe Adjusted EBITDA is also used by and is useful to investors and other users of our financial statements in evaluating our operating performance because it provides them with an additional tool to compare business performance across companies and across periods. We believe that EBITDA is widely used by investors to measure a company's operating performance without regard to items such as interest expense, taxes, depreciation and amortization, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired.

Additionally, we believe that investors commonly adjust EBITDA information to eliminate the effect of restructuring and other expenses, which vary widely from company to company and impair comparability. As we define it, Adjusted EBITDA represents EBITDA adjusted for the effects of impairment losses, gains or losses on sales, dispositions or retirements of assets, any unrealized gains or losses and any non-cash realized gains or losses from accounting for derivatives, stock-based compensation expense, operating lease expense, non-cash gains and losses from foreign currency translations, reorganization items, major maintenance expense, gains or losses on the repurchase or extinguishment of debt and any other extraordinary, unusual or non-recurring items plus the Adjusted EBITDA from our discontinued operations and adjustments to reflect the Adjusted EBITDA from our unconsolidated investments. We adjust for these items in our Adjusted EBITDA as our management believes that these items would distort their ability to efficiently view and assess our core operating trends.

In summary, our management uses Adjusted EBITDA as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends, as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations, and in communications with our Board of Directors, shareholders, creditors, analysts and investors concerning our financial performance.

The tables below provide a reconciliation of Adjusted EBITDA to our income (loss) from operations on a segment basis and to net income attributable to Calpine on a consolidated basis for years ended December 31, 2010, 2009 and 2008 (in millions).

	2010					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 31
Discontinued operations, net of tax expense						(193)
Income tax benefit						(68)
Other (income) expense and debt extinguishment costs, net						106
(Gain) loss on interest rate derivatives, net						247
Interest expense, net						778
Income from operations	$ 380	$ 237	$ 250	$ 27	$ 7	$ 901
Add:						
Adjustments to reconcile income from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	207	150	111	112	(7)	573
Impairment loss	97	—	—	19	—	116
Major maintenance expense	27	87	18	25	—	157
Operating lease expense	19	—	26	—	—	45
Unrealized (gains) on commodity derivative mark-to-market activity	(54)	(54)	(17)	(18)	—	(143)
Gain on sale of assets	—	(119)	—	—	—	(119)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(2)(3)	—	—	34	—	—	34
Stock-based compensation expense	11	8	2	3	—	24
Non-cash loss on dispositions of assets	—	9	—	1	—	10
Conectiv acquisition-related costs(4)	—	—	36	—	—	36
Other	2	—	1	—	—	3
Adjusted EBITDA from continuing operations	689	318	461	169	—	1,637
Adjusted EBITDA from discontinued operations	75	—	—	—	—	75
Total Adjusted EBITDA	$ 764	$ 318	$ 461	$ 169	$ —	$ 1,712

	2009					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 149
Net loss attributable to noncontrolling interest						(4)
Discontinued operations, net of tax expense						(35)
Income tax expense						15
Reorganization items						(1)
Other (income) expense and debt extinguishment costs, net						90
Interest expense, net						799
Income from operations	$ 681	$ 166	$ 126	$ 47	$ (7)	$ 1,013
Add:						
Adjustments to reconcile income from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	186	130	67	84	(8)	459
Impairment loss	4	—	—	—	—	4
Major maintenance expense	77	49	5	32	—	163
Operating lease expense	21	—	26	—	—	47
Unrealized (gains) losses on commodity derivative mark-to-market activity	(110)	59	(42)	14	—	(79)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(2)(3)	(16)	—	33	—	—	17
Stock-based compensation expense	17	12	3	6	—	38
Non-cash loss on dispositions of assets	11	14	2	5	—	32
Other	6	—	—	—	—	6
Adjusted EBITDA from continuing operations	877	430	220	188	(15)	1,700
Adjusted EBITDA from discontinued operations	82	—	—	—	—	82
Total Adjusted EBITDA	$ 959	$ 430	$ 220	$ 188	$ (15)	$ 1,782

	2008					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 10
Net loss attributable to noncontrolling interest						(1)
Discontinued operations, net of tax expense						(36)
Income tax benefit						(56)
Reorganization items						(302)
Other (income) expense and debt extinguishment costs, net						21
Interest expense, net						998
Income (loss) from operations	$ 320	$ 427	$ 37	$ (168)	$ 18	$ 634
Add:						
Adjustments to reconcile income (loss) from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	177	129	56	92	(5)	449
Impairment loss	13	—	—	213	—	226
Major maintenance expense	89	62	14	20	(1)	184
Operating lease expense	21	—	25	—	—	46
Non-cash realized gains on derivatives	—	(40)	—	—	—	(40)
Unrealized (gains) losses on commodity derivative mark-to-market activity	86	(138)	44	(27)	—	(35)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(2)(3)	55	—	15	6	—	76
Stock-based compensation expense	23	16	3	8	—	50
Non-cash loss on dispositions of assets	9	12	3	10	(1)	33
Other	(6)	3	(1)	—	—	(4)
Adjusted EBITDA from continuing operations	787	471	196	154	11	1,619
Adjusted EBITDA from discontinued operations	80	—	—	—	—	80
Total Adjusted EBITDA	$ 867	$ 471	$ 196	$ 154	$ 11	$ 1,699

(1) Depreciation and amortization expense in the income (loss) from operations calculation on our Consolidated Statements of Operations excludes amortization of other assets.

(2) Included in our Consolidated Statements of Operations in (income) loss from unconsolidated investments in power plants.

(3) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include $1 million, $(47) million and $55 million in unrealized (gains) losses on mark-to-market activity for the years ended December 31, 2010, 2009 and 2008, respectively.

(4) Includes $26 million included in sales, general and other administrative expense and $10 million included in plant operating expense.

LIQUIDITY AND CAPITAL RESOURCES

Our business is capital intensive. Our ability to successfully implement our strategy is dependent on the continued availability of capital on attractive terms. In addition, our ability to successfully operate our business and to meet certain near-term debt repayment obligations is dependent on maintaining sufficient liquidity. We believe that we have adequate resources from a combination of cash and cash equivalents on hand and cash expected to be generated from future operations to continue to meet our obligations as they become due.

Liquidity

As of December 31, 2010, we had $1,327 million in cash and cash equivalents and $248 million of restricted cash. Amounts available for future borrowings were $557 million under our Corporate Revolving Facility and $66 million under our NDH Project Debt. The following table provides a summary of our liquidity position at December 31, 2010 and 2009 (in millions):

	2010	2009
Cash and cash equivalents, corporate[1]	$ 1,058	$ 725
Cash and cash equivalents, non-corporate	269	264
Total cash and cash equivalents	1,327	989
Restricted cash	248	562
Letter of credit availability[2]	35	34
Revolver availability[3]	623	794
Total current liquidity availability	$ 2,233	$ 2,379

(1) Includes $6 million and $9 million of margin deposits held by us posted by our counterparties as of December 31, 2010 and 2009, respectively.

(2) Additional available balances for Calpine Development Holdings, Inc. Letter of credit were increased by $50 million to $200 million on June 30, 2010.

(3) On December 10, 2010, we executed our $1.0 billion Corporate Revolving Facility, which replaced our $1.0 billion revolver under our First Lien Credit Facility and allows for up to $750 million of availability for the issuance of letters of credit and up to $50 million as a swingline subfacility. At December 31, 2010, the letters of credit issued under our First Lien Credit Facility were either replaced by letters of credit issued by the Corporate Revolving Facility or back-stopped by an irrevocable standby letter of credit issued by Deutsche Bank AG New York Branch. Our letters of credit under our Corporate Revolving Facility as of December 31, 2010 include those that were back-stopped of approximately $83 million; however, we expect that the back-stopped letters of credit will be returned and extinguished in early 2011.

Our principal source for future liquidity is cash flows generated from our operations. Accordingly, our ability to maximize our Commodity Margin and improve the efficiency and profitability of our operations is key in maintaining sufficient future liquidity. Our principal uses of liquidity and capital resources, outside of those required for our operations, include, but are not limited to, collateral requirements to support our commercial hedging and optimization activities, debt service obligations including principal and interest payments and capital expenditures for construction, project development and other growth initiatives. We believe that cash on hand and expected future cash flows from operations will be sufficient to meet our liquidity needs for our operations, both in the near and longer term.

Liquidity Sensitivity

Significant changes in commodity prices and Market Heat Rates can have an impact on our liquidity as we use margin deposits, cash prepayments and letters of credit as credit support (collateral) with and from our counterparties for commodity procurement and risk management activities. Utilizing our portfolio of transactions subject to collateral exposure, we estimate that as of January 28, 2011, an increase of $1/MMBtu in natural gas prices would result in an increase of collateral required by approximately $170 million. If natural gas prices decreased by $1/MMBtu, we estimate that our collateral requirements would decrease by approximately $170 million. Changes in Market Heat Rates also affect our liquidity. For example, as demand increases, less efficient generation is dispatched, which increases the Market Heat Rate and results in increased collateral requirements. Historical relationships of natural gas and Market Heat Rate movements for our portfolio of assets have been volatile over time; therefore, we derived a statistical analysis that implies that a change of $1/MMBtu in natural gas approximates an average Market Heat Rate change of 300 Btu/KWh. We estimate that as of January 28, 2011, an increase of 300 Btu/KWh in the Market Heat Rate would result in an increase in collateral required by approximately $29 million. If Market Heat Rates were to fall at a similar rate, we estimate that our collateral required would decrease by $36 million. These amounts are not necessarily indicative of the actual amounts that could be required, which may be higher or lower than the amounts estimated above.

In order to effectively manage our future Commodity Margin, we have economically hedged a substantial portion of our generation and natural gas portfolio mostly through power and natural gas forward physical and financial transactions for 2011; however, we remain susceptible to significant price movements for 2012 and beyond. In addition to the price of natural gas, the future impact on our Commodity Margin is highly dependent on other factors such as:

- the level of Market Heat Rates;
- our continued ability to successfully hedge our Commodity Margin;
- the speed, strength and duration of an economic recovery, if any;
- maintaining acceptable availability levels for our fleet;
- improving the efficiency and profitability of our operations;
- continued compliance with the covenants under our existing financing obligations, including our First Lien Notes, Corporate Revolving Facility, CCFC and NDH Project Debt as well as other debt obligations;
- stabilizing and increasing future contractual cash flows; and
- our significant counterparties performing under their contracts with us.

Additionally, scheduled outages related to the life cycle of our power plant fleet in addition to unscheduled outages may result in maintenance expenses that are disproportionate in differing periods. In order to manage such liquidity requirements, we maintain additional liquidity availability in the form of our Corporate Revolving Facility and NDH revolver (both noted in the table above), letters of credit and the ability to issue first priority liens for collateral support. However, it is difficult to predict future developments and the amount of credit support that we may need to provide should such conditions occur, we experience another economic recession that persists for a significant period of time or energy commodity prices increase significantly.

Management of our debt service obligations and future expected capital expenditures for construction, project development and other growth initiatives are further discussed below.

In order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to our counterparties, we have granted additional liens on the assets currently subject to liens under our First Lien Notes and Corporate Revolving Facility to collateralize our obligations under certain of our power and natural gas agreements that qualify as "eligible commodity hedge agreements" under our Corporate Revolving Facility and certain of our interest rate swap agreements. The counterparties under such agreements will share the benefits of the collateral subject to such liens ratably with the lenders under our First Lien Notes and Corporate Revolving Facility. During 2010, we have increased our usage of these additional liens in order to help manage cash collateral that would otherwise be required. See Note 9 of the Notes to Consolidated Financial Statements for further information on our margin deposits and collateral used for commodity procurement and risk management activities.

Letter of Credit Facilities — The table below represents amounts issued under our letter of credit facilities as of December 31, 2010 and 2009 (in millions):

	December 31, 2010	December 31, 2009
Corporate Revolving Facility[(1)]	$ 443	$ —
First Lien Credit Facility[(1)]	—	206
Calpine Development Holdings, Inc.[(2)]	165	116
NDH Credit Facility	34	—
Various project financing facilities	69	90
Total	$ 711	$ 412

(1) When we entered into our Corporate Revolving Facility on December 10, 2010, the letters of credit issued under our First Lien Credit Facility were either replaced with letters of credit issued by our Corporate Revolving Facility or back-stopped by an irrevocable standby letter of credit issued by Deutsche Bank AG New York Branch. Our letters of credit under our Corporate Revolving Facility as of December 31, 2010 includes those that were back-stopped of approximately $83 million; however, we expect that the back-stopped letters of credit will be returned and extinguished in early 2011.

(2) Availability under the Calpine Development Holdings, Inc. letter of credit was increased by $50 million to $200 million on June 30, 2010.

Cash Management

We manage our cash in accordance with our intercompany cash management system subject to the requirements of our First Lien Notes and Corporate Revolving Facility and requirements under certain of our project debt and lease agreements or by regulatory agencies. Our cash and cash equivalents, as well as our restricted cash balances, generally exceed FDIC insured limits or are invested in money market accounts with investment banks that are not FDIC insured. We place our cash, cash equivalents and restricted cash in what we believe to be credit-worthy financial institutions and certain of our money market accounts invest in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. Government, its agencies or instrumentalities.

We do not expect to pay any cash dividends on our common stock for the foreseeable future. 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 and financing restrictions and such other factors as our Board of Directors may deem relevant.

Capital Management and Significant Transactions

In connection with our goals of enhancing shareholder value and leveraging our three scale regions, we have completed several significant capital and financing transactions during 2010 and January of 2011. Some of our more significant transactions are described below. While we cannot provide any assurance that we will continue to be successful in the future, if credit and capital markets present favorable opportunities, we will continue to execute future transactions consistent with our strategy.

Issuance of the First Lien Notes, Termination of the First Lien Credit Facility and extension of our Debt Maturities

Beginning in the fourth quarter of 2009 and through January of 2011, we issued First Lien Notes in a series of tranches with maturity dates in 2017, 2019, 2020, 2021 and 2023. The proceeds from those issuances, together with operating cash, were used to fully repay all of our outstanding term loan borrowings under our First Lien Credit Facility, thereby terminating the First Lien Credit Facility in accordance with its terms. See Note 6 of the Notes to Consolidated Financial Statements for further discussion of the issuance of the First Lien Notes and the termination of the First Lien Credit Facility. The issuance of the First Lien Notes, the refinancing of the First Lien Credit Facility revolver with the Corporate Revolving Facility (discussed below) and the resulting termination of the First Lien Credit Facility, provide us with significant benefits. The termination of the First Lien Credit Facility eliminated the more restrictive of our debt covenants, resulting in increased operational, strategic and financial flexibility in managing our capital resources including the flexibility to reinvest more earnings for internal growth, issue and/or buyback shares of our common stock and incur additional debt, if needed for acquisition or development. Additionally, we significantly smoothed and extended contractual debt maturities of approximately $4.7 billion (as of December 31, 2009), due in 2014, such that no more than $2.0 billion of our corporate debt matures in any one year. Under the First Lien Notes and Corporate Revolving Facility, subject in each case to the limitations contained therein and in the Collateral Agency and Intercreditor Agreement, we may:

- re-invest future earnings internally for additional growth and/or may elect to return cash to shareholders;
- issue and/or buyback additional shares of our common stock;
- incur additional first lien indebtedness up to certain consolidated net tangible asset ratios;
- incur additional subordinated or junior secured debt; and
- use corporate resources to freely invest in our subsidiaries which are not first lien guarantors.

Additionally, except as required under certain of our project debt, we are no longer subject to an excess cash flow payment calculation or cash sweeps, and we are no longer limited in the amount of capital expenditures for future growth.

Corporate Revolving Facility

On December 10, 2010, we entered into the Corporate Revolving Facility in an aggregate amount of $1.0 billion, of which, up to $750 million will be available for the issuance of letters of credit and up to $50 million will be available as a swingline subfacility. The Corporate Revolving Facility may be increased or we may add one or more incremental revolving credit facilities, on one or more occasions, up to an additional $250 million in the aggregate under certain circumstances as provided in the credit agreement. The Corporate Revolving Facility replaced the $1.0 billion revolver under the First Lien Credit Facility. The Corporate Revolving Facility will be utilized for our (and to the extent permitted therein, our subsidiaries') working capital requirements and other general corporate purposes.

Conectiv Acquisition and NDH Project Debt

On July 1, 2010, we, through our indirect, wholly owned subsidiary NDH, completed the Conectiv Acquisition. We financed the transaction through a $1.3 billion seven year senior secured term facility provided under the NDH Project Debt with the remaining amounts funded with cash on hand. The assets acquired include 18 operating power plants and one plant under construction, with approximately 4,490 MW of capacity (including completion of the York Energy Center under construction and scheduled upgrades). The Conectiv Acquisition gives us significant presence in the Mid-Atlantic market. We did not acquire Conectiv's trading book, load serving auction obligations or collateral requirements. Additionally, we did not assume any of Conectiv's off-site environmental liabilities, environmental remediation liabilities in excess of $10 million related to assets located in New Jersey that are subject to ISRA, or pre-close accumulated pension and retirement welfare liabilities; however, we assumed pension liabilities of approximately $6 million on future services and compensation increases for past services for 129 union employees who joined Calpine as a result of the Conectiv Acquisition on the acquisition date. Our purchase price was approximately $1.64 billion. See also Notes 3 and 6 of the Notes to Consolidated Financial Statements for further discussion of our Conectiv Acquisition and NDH Project Debt.

As part of the Conectiv Acquisition and NDH Project Debt, we entered into various intercompany agreements with our NDH subsidiaries for the related sales and purchases of power, natural gas and the operation and maintenance of our NDH power plants, which will not materially impact our results of operations, financial condition or cash flows on a consolidated basis. While there is no direct recourse by holders of the NDH Project Debt to Calpine Corporation, a substantial portion of the commodity price risk related to NDH's power generation is absorbed by Calpine Energy Services, L.P. an indirect, wholly owned subsidiary of Calpine Corporation, which purchases the power generated by NDH under an intercompany tolling agreement, which is also guaranteed by Calpine Corporation.

Sale of Blue Spruce and Rocky Mountain

On December 6, 2010, we, through our wholly owned subsidiaries Riverside Energy Center, LLC and Calpine Development Holdings, Inc., sold 100% of our ownership interests in Blue Spruce and Rocky Mountain to PSCo for approximately $739 million, subject to certain working capital adjustments. Both power plants provided power and capacity to PSCo under PPAs, which materially expire in 2013 and 2014. The sale removed the restrictions on approximately $78 million in restricted cash at closing. We used the sales proceeds and the approximately $78 million in restricted cash described above to repay project debt of approximately $418 million, for general corporate purposes, to strengthen our balance sheet and to focus more resources on our core markets. We also recorded a pre-tax gain of approximately $209 million upon closing this transaction which is reported in discontinued operations on our Consolidated Statement of Operations. See also Note 3 of the Notes to Consolidated Financial Statements for additional details of the Blue Spruce and Rocky Mountain amounts reported as discontinued operations.

Other Acquisitions and Divestitures

Acquisition of Broad River and South Point Leases — On December 8, 2010, we, through our wholly owned, indirect subsidiary, Calpine BRSP, purchased entities from CIT Capital USA Inc. that held the leases for our Broad River and South Point power plants by assuming debt with a fair value of approximately $297 million and a cash payment of approximately $40 million. Prior to this purchase, our Broad River power plant was operated under a sale-leaseback transaction that was accounted for as a financing transaction and our South Point power plant was accounted for as an operating lease. The purchase of the entities holding the power plant leases only added an incremental $85 million in consolidated debt, as the transaction eliminated approximately $212 million recorded as debt and accrued interest owed to CIT Capital USA Inc. under our Broad River power plant lease.

We recorded a total pre-tax loss of approximately $125 million on our Consolidated Statement of Operations for the year ended December 31, 2010 for this transaction, which was recorded as shown below (in millions):

Broad River: debt extinguishment costs	$ 30
South Point: impairment losses	95
Total non-cash loss recorded for this transaction	$ 125

While the transaction results in a one-time loss, in the longer-term, the acquisition of these entities grants us greater flexibility and more control of the future operation of both plants and simplified a previously complex leasing arrangement. See also Note 3 of the Notes to Consolidated Financial Statements for additional details of our purchase of our Broad River and South Point leases.

Freestone — On December 8, 2010, we sold a 25% undivided interest in the assets of our Freestone power plant for approximately $215 million in cash. We recorded a pre-tax gain of approximately $119 million in December 2010, which is included in gain on sale of assets on our Consolidated Statement of Operations. We continue to operate Freestone after the sale.

Pittsburg Power Plant and Watsonville (Monterey) Cogeneration Power Plant — We no longer operate these power plants which had an aggregate capacity of 93 MW. In March 2010, we transferred ownership of our Pittsburg power plant to a third party pursuant to a transfer agreement executed in August 2007. The operating lease associated with our Watsonville (Monterey) cogeneration power plant expired in May 2010, at which time we began dismantling the power plant in accordance with the lease agreement.

Prior Period Asset Sales and Purchase — We did not have any significant acquisitions or divestitures in 2009; however, a significant component of our Chapter 11 restructuring activities during 2008 and prior periods was to return our focus to our core strategic assets. During 2008, we sold the Fremont and Hillabee development projects and our equity interests in Auburndale. In addition, we purchased the assets of the RockGen Energy Center in 2008. See Notes 3 and 5 of the Notes to Consolidated Financial Statements for additional discussion of these asset sales and purchase.

Construction, Upgrades and Growth Initiatives

Our goal is to continue to grow our presence in core markets with an emphasis on expansions or upgrades of existing power plants. We intend to take advantage of favorable opportunities to continue to design, develop, acquire, construct and operate the next generation of highly efficient, operationally flexible and environmentally responsible power plants where such investment meets our rigorous financial hurdles, particularly if power contracts and financing are available and attractive returns are expected. We will consider selective acquisitions or additions of new capacity supported by long-term hedging programs, including PPAs and natural gas tolling agreements, particularly where limited or non-recourse project financing is available. In addition, we believe that upgrades and expansions to our current assets offer proven and financially disciplined opportunities to improve our operations, capacity and efficiencies. Our significant projects under construction, growth initiatives and upgrades are discussed below.

York Energy Center

We acquired the York Energy Center, a 565 MW dual fuel, combined-cycle power plant under construction in Peach Bottom Township, Pennsylvania, formerly known as the Delta Project, as part of the Conectiv Acquisition. All permits have been received and COD is expected in March 2011, three months early and approximately $20 million under budget. The York Energy Center will sell power under a six year PPA with a third party. We do not expect to require additional financing to complete construction.

Russell City Energy Center

Russell City Energy Center continues to move forward and is currently contracted to deliver its full output to PG&E under a ten year PPA. We are in possession of all required approvals and permits, subject to on-going judicial appeals. The expected COD is in 2013. Upon completion, this project will bring on line approximately 429 MW of net interest baseload capacity (464 MW with peaking capacity) representing our expected 75% share. We began construction in 2010, and we are in the process of obtaining project financing. Russell City Energy Center is a 619 MW, natural gas-fired, combined cycle power plant to be located in

Hayward California. In September 2006, we sold a 35% equity interest in the power plant to Aircraft Services (an Affiliate of GE) for future contributions of approximately $44 million and Aircraft Services' obligation to post a $37 million letter of credit. Under the LLC agreement with Aircraft Services, Aircraft Services' equity is to be applied toward the completion of development and construction of the power plant, and Aircraft Services is also to provide related credit support for the project. Under the LLC operating agreement, Aircraft Services' original 35% percentage interest in Russell City fluctuates based on, among other things, the amount of capital contributions made by each party to fund development costs and on the amount of collateral posted by each party. While Aircraft Services' interest is currently 35%, they are currently funding their construction obligations at 25%. Aircraft Services' ownership interest will no longer fluctuate and will finalize upon closing of construction financing in 2011. For accounting purposes, we report all of our accounting information based upon our legal 65% share; however, our presentation of MW capacity under construction in this Report includes our expected 75% share.

Los Esteros

During 2009, we and PG&E negotiated a new PPA to replace the existing California Department of Water Resources contract and facilitate the upgrade of our Los Esteros Critical Energy Facility from a 188 MW simple-cycle generation power plant to a 308 MW combined-cycle generation power plant, which will also increase the efficiency and environmental performance of the power plant by lowering the Heat Rate. The PPA and related agreements with PG&E have received all of the necessary approvals and licenses, which are now effective. The California Energy Commission has renewed our license and emission limits, but the appeal period has not yet expired. We are in the process of procuring equipment and selecting the engineering, procurement and construction contractors. We expect COD during the third quarter of 2013.

Turbine Upgrades

We continue to move forward with our turbine upgrade program and have entered into an agreement to upgrade select GE and Siemens turbines. Through January 2011, we have completed the upgrade of six Siemens turbines and have agreed to upgrade approximately 15 additional Siemens and GE turbines (and may upgrade additional turbines in the future). Our turbine upgrade program is expected to increase our generation capacity in total by approximately 275 MW. This upgrade program began in the fourth quarter of 2009 and is scheduled through 2014. The upgraded turbines have been operating with Heat Rates falling in line with expectations.

Geysers Assets Expansion

We continue to look to expand our production from our Geysers Assets. Beginning in the fourth quarter of 2009, we conducted an exploratory drilling program, which effectively proved the commercial viability of the steam field in the northern part of our Geysers Assets; however, permitting challenges have emerged that we are working our way through. We were planning to target a 2013 COD for an expansion of our Geysers Assets and had been, in parallel, negotiating commercial arrangements to support that, but the permitting delay has increased the risk we will not meet a target 2013 COD. We continue to believe our northern Geysers Assets have potential for development. In the near term, we will work to connect the test wells we have drilled over the last year to our existing power plants and will work to capture incremental MW from those wells, while continuing with the permitting process, baseline engineering work and sales efforts for an expansion target COD subsequent to 2013.

Major Maintenance and Capital Spending

Our major maintenance and capital spending remains an important part of our business. Our expected expenditures for 2011 are the following (in millions):

	2011
Major maintenance expense, net of expected grants	$ 235
Capital expenditures, operations	155
Growth related capital expenditures	445
Total major maintenance expense and capital spending	835
Less: Amounts expected to be funded with financing	(290)
Net major maintenance expense and capital spending	$ 545

NOLs

We have significant NOLs that will provide future tax deductions when we generate sufficient taxable income during the applicable carryover periods. Our federal and state income tax reporting group is comprised primarily of two groups, CCFC and its subsidiaries, which we refer to as the CCFC group and Calpine Corporation and its subsidiaries other than CCFC, which we refer to as the Calpine group. As of December 31, 2010, our consolidated federal NOLs totaled approximately $7.4 billion, which consisted of approximately $6.9 billion from the Calpine group and approximately $472 million from the CCFC group. The Calpine group has recorded a valuation allowance against the deferred tax assets for a majority of their NOLs as we determined it is more likely than not that they will expire unutilized. In 2011, we may elect to consolidate our CCFC group with our Calpine group for federal income tax purposes. If we elect to consolidate our tax reporting groups, it is reasonably possible that the reversal of the CCFC group deferred tax liabilities with our Calpine group NOLs will allow us to realize more of our Calpine group NOLs, thereby reducing the valuation allowance. Although this election would not significantly impact our 2011 tax payments, the result could have a significant impact on our income tax expense reported in 2011. See Note 10 of the Notes to Consolidated Financial Statements for additional discussion of our Calpine and CCFC groups.

Cash Flow Activities

The following table summarizes our cash flow activities for the years ended December 31, 2010, 2009 and 2008 (in millions):

	2010	2009	2008
Beginning cash and cash equivalents	$ 989	$ 1,657	$ 1,915
Net cash provided by (used in):			
Operating activities	929	761	494
Investing activities	(831)	(250)	516
Financing activities	240	(1,179)	(1,268)
Net increase (decrease) in cash and cash equivalents	338	(668)	(258)
Ending cash and cash equivalents	$ 1,327	$ 989	$ 1,657

2010 — 2009

Net Cash Provided By Operating Activities

Cash provided by operating activities for the year ended December 31, 2010, improved to $929 million compared to $761 million for the year ended December 31, 2009. Our improvement in cash provided by operating activities was primarily due to:

- *Working capital* — Working capital employed, after adjusting for debt related balances and derivative activities which did not impact cash provided by operating activities, decreased by approximately $188 million for the year ended December 31, 2010 compared to 2009. The decrease was primarily due to reduced commodity margin requirements.

- *Interest paid* — Cash paid for interest, inclusive of interest rate swaps in hedging relationships, decreased by $126 million to $635 million for the year ended December 31, 2010, as compared to $761 million for 2009, primarily due to the timing of interest payments and the replacement of the First Lien Credit Facility with First Lien Notes at lower fixed interest rates.
- *Reorganization items* — Cash payments for reorganization items decreased by $5 million.

Our improvements in cash provided by operating activities were partially offset by the following:

- *Income from operations* — Income from operations, adjusted for non-cash items decreased by $43 million for the year ended December 31, 2010, as compared to 2009. Non-cash items consist primarily of depreciation and amortization, gains and losses on sales of assets, impairment losses, income and losses from unconsolidated investments and unrealized gains and losses in mark to market activity.
- *Cash taxes* — Net cash paid for taxes in 2010 was approximately $17 million compared to net cash received for taxes of approximately $37 million in 2009. In 2009, we received refunds from foreign tax jurisdictions with no such refunds in 2010.

Net Cash Provided By (Used In) Investing Activities

Cash flows used in investing activities for the year ended December 31, 2010, were $831 million compared to cash flows used in investing activities of $250 million for the year ended December 31, 2009. The increase in cash flows used in investing activities was primarily due to:

- *Purchase of Conectiv assets* — We purchased the Conectiv assets for $1.6 billion in the year ended December 31, 2010. There were no acquisitions in 2009.
- *Capital expenditures* — Capital expenditures increased by $190 million primarily resulting from construction activity at the York and Russell City Energy Centers combined with our Geysers Assets expansion activities.
- *Settlement of non-hedging interest rate swaps* — In the year ended December 31, 2010 we paid $69 million on interest rate swap losses associated with swaps that formerly hedged the variable rate debt which was converted to fixed rate debt in the year. Since these payments were recognized in net income and effectively reduced our interest payable, the offset to the amount reflected in net cash provided by (used in) investing activities is included in the reconciliation of net income to net cash provided by operating activities in the line item accounts payable, LSTC and accrued expenses on our Consolidated Statements of Cash Flows.

The increase in cash flows used in investing activities was partially offset by:

- *Decrease in restricted cash* — Restricted cash decreased $322 million in 2010 compared to a $59 million increase in 2009. The decrease was primarily due to releases of restrictions on cash resulting from the repayment of project debt.
- *Sales of power plants, interests and other* — We received proceeds of approximately $954 million from the sale of our 100% ownership interests in Blue Spruce and Rocky Mountain, combined with the sale of a 25% undivided interest in the assets of our Freestone power plant. We had no significant asset sales in 2009.

Net Cash Provided By (Used In) Financing Activities

Cash flows provided by financing activities increased approximately $1.4 billion to $240 million for the year ended December 31, 2010, compared to cash flows used in financing activities of approximately $1.2 billion for the comparable period in 2009. The change in cash flows provided by financing activities was primarily related to:

- *Issuance of the First Lien Notes* — In the year ended December 31, 2010, we received proceeds of approximately $3.5 billion from the issuance of First Lien Notes. We used these proceeds to make repayments on the First Lien Credit Facility of approximately $3.4 billion resulting in a net increase of $50 million.

- *Lower Repayments on the First Lien Credit Facility* — In the year ended December 31, 2010, we made regularly scheduled payments on the First Lien Credit Facility of approximately $36 million, a decrease of $24 million compared to payments of $60 million for the year ended December 31, 2009. Additionally, in the year ended December 31, 2009, we repaid $725 million on our First Lien Credit Facility revolver.

- *Increase in Project Debt* — In the year ended December 31, 2010, we received proceeds of approximately $1.3 billion from project debt used to finance the Conectiv Acquisition, a $238 million increase compared to project debt issued in the year ended December 31, 2009, which was primarily due to the refinancing of CCFC.

- *Lower Repayments of Project Debt* — In the year ended December 31, 2010, we made repayments on project debt of approximately $937 million, a decrease of $424 million compared to the prior year. The decrease is primarily due to the repayment of approximately $418 million related to the Blue Spruce and Rocky Mountain transaction in 2010, compared to approximately $1.1 billion of repayments related to the CCFC refinancing in 2009. Additionally, we made higher payments of approximately $239 million on other project debt in the year ended December 31, 2010.

- *Increased Finance Costs* — The increase in cash flows provided by financing activities was partially offset by an increase in finance costs of $71 million. In the year ended December 31, 2010, we incurred $136 million in finance costs primarily related to the issuance of the First Lien Notes and project debt, compared to $65 million incurred in 2009 to facilitate an amendment to the First Lien Credit Facility and to refinance other project debt.

2009 — 2008

Net Cash Provided By Operating Activities

Cash provided by operating activities for the year ended December 31, 2009, improved to $761 million compared to $494 million for the year ended December 31, 2008. Our improvement in cash provided by operating activities was primarily due to:

- *Income from operations* — Income from operations, adjusted for non-cash items increased by $42 million for the year ended December 31, 2009, as compared to 2008. Non-cash items consist primarily of depreciation and amortization, gains and losses on sales of assets, impairment losses, income and losses from unconsolidated investments and unrealized gains and losses in mark-to-market activity.

- *Interest paid* — Cash paid for interest decreased by $299 million to $761 million for the year ended December 31, 2009, as compared to approximately $1.1 billion for 2008, primarily due to the repayment of the Second Priority Debt, and, to a lesser extent, lower interest rates for the comparable period in 2009.

- *Reorganization items* — Cash payments for reorganization items decreased by $115 million.

- *Cash taxes* — Net cash received for taxes increased by $33 million.

Our improvements in cash provided by operating activities were partially offset by:

- *Working capital* — Working capital employed, after adjusting for debt related balances and derivative activities which did not impact cash provided by operating activities, increased by approximately $152 million for the year ended December 31, 2009 compared to 2008. The increase was primarily due to the sale during 2008 of assets previously reflected as assets held for sale at December 31, 2007 offset by a net reduction in working capital employed in 2009 for net accounts receivable and payable.

- *Debt extinguishment costs* — Cash payments for debt extinguishment costs in 2009 were $39 million related to the CCFC Refinancing, compared to cash payments of $6 million related to the refinancing of Blue Spruce and Metcalf in 2008.

Net Cash Provided By (Used In) Investing Activities

Cash flows used in investing activities for the year ended December 31, 2009, were $250 million compared to cash flows provided by investing activities of $516 million for the year ended December 31, 2008. The decrease in cash flows from investing activities was primarily due to:

- *Sales of power plants, turbines and investments* — We had no significant asset sales in 2009 compared to $413 million of cash received primarily from the sales of the Fremont and Hillabee development projects in 2008.

- *Sales of discontinued operations* — We had no significant asset sales in 2009 compared to $79 million of cash received from the sale of Rosetta in 2008.

- *Reconsolidation of our Canadian Debtors and other deconsolidated foreign entities* — In 2008, we had a favorable cash effect of $64 million from the reconsolidation of our Canadian Debtors and other deconsolidated foreign entities.

- *Contributions to unconsolidated investments* — Contributions increased by $2 million in 2009 primarily due to the funding of OMEC offset by reduced contributions to Greenfield LP.

- *Return of investment from unconsolidated investments* — For the year ended December 31, 2009, we received distributions of $9 million compared to $27 million for the year ended December 31, 2008.

- *Capital expenditures* — Capital expenditures increased by $36 million resulting from our maintenance programs and turbine upgrades.

- Increase in restricted cash — Restricted cash increased $59 million in 2009 compared to a $78 million decrease in 2008 primarily due to our refinancing activities.

Net Cash Used In Financing Activities

Due to our emergence from Chapter 11 during the first quarter of 2008, our financing activities are not directly comparable. Cash used in financing activities for the year ended December 31, 2009, resulted in a net outflow of $1.2 billion compared to a net outflow of $1.3 billion for the same period in 2008. Our significant cash flows from our 2009 and 2008 financing transactions are described below:

- During the year ended December 31, 2009, we repaid approximately $725 million previously drawn on our First Lien Credit Facility revolver, and we made a net pay down of approximately $119 million when we refinanced the CCFC Old Notes, CCFC Term Loans and CCFC Preferred Shares with the CCFC Notes. We also made scheduled repayments of approximately $60 million under our First Lien Credit Facility term loans and $280 million on notes payable, project debt and capital lease obligations.

- During 2008, we borrowed approximately $4.2 billion under our First Lien Facilities and used that borrowing and cash on hand to repay approximately $3.7 billion of the Second Priority Debt, $1.1 billion on the senior secured revolver, $300 million on the bridge facility and $143 million of First Lien Credit Facility term loans. In addition, we received proceeds of $355 million from refinancing Metcalf and Blue Spruce and repaid $585 million of other project debt, capital leases and notes payable.

- We incurred finance costs of $65 million in 2009 to facilitate an amendment to our First Lien Credit Facility term loans and to refinance CCFC, Deer Park and other project debt. During the year ended December 31, 2008, we incurred $207 million of finance costs primarily related to closing on our First Lien Facilities.
- We received $64 million from the settlement of derivatives with an other-than-insignificant financing element for the year ended December 31, 2008.

Counterparties and Customers

Our counterparties primarily consist of three categories of entities who participate in the wholesale energy markets: financial institutions and trading companies; regulated utilities, municipalities, cooperatives and other retail power suppliers; and oil, natural gas, chemical and other energy-related industrial companies. We have exposure to trends within the energy industry, including declines in the creditworthiness of our marketing counterparties. Currently, certain of our marketing counterparties within the energy industry have below investment grade credit ratings. However, we do not currently have any significant exposures to counterparties that are not paying on a current basis.

Credit Considerations

Our credit rating has, among other things, generally required us to post significant collateral with our hedging counterparties. Our collateral is generally in the form of cash deposits, letters of credit or first liens on our assets. See also Note 9 of the Notes to Consolidated Financial Statements for our use of collateral. Our credit rating has also reduced the number of hedging counterparties willing to extend credit to us and reduced our ability to negotiate more favorable terms with them. However, we believe that we will continue to be able to work with our hedging counterparties to execute beneficial hedging transactions and provide adequate collateral.

In May 2010, Moody's Investors Service upgraded Calpine Corporation's credit rating to B1 with a stable outlook. According to Moody's credit opinion, the rating upgrade was a result of our recent efforts to produce more predictable cash flow and earnings through securing new contracts for projects under development, new bilateral arrangements with several of our customers and new revenue sources as a result of the Conectiv Acquisition, which improved cash flow predictability through the addition of capacity payments to our portfolio. As of December 31, 2010, our First Lien Notes, Corporate Revolving Facility and our corporate rating had the following ratings and commentary from Standard and Poor's and Moody's Investors Service:

	Standard and Poor's	Moody's Investors Service
First Lien Notes and Corporate Revolving Facility rating	B+	B1
Corporate rating	B	B1
Commentary	Stable	Stable

Off Balance Sheet Commitments of Our Power Plant Operating Leases and Our Unconsolidated Subsidiaries

Some of our power plant operating leases include certain sale/leaseback transactions that are not reflected on our balance sheet. All counterparties in these transactions are third parties that are unrelated to us. The sale/leaseback transactions utilize special purpose entities formed by the equity investors with the sole purpose of owning a power plant. Some of these operating leases contain customary restrictions on dividends up to Calpine Corporation, additional debt and further encumbrances similar to those typically found in project finance debt instruments. We have no ownership or other interest in any of these special purpose entities. See Note 15 of the Notes to Consolidated Financial Statements for the future minimum lease payments under our power plant operating leases.

Some of our unconsolidated equity method investments have debt that is not reflected on our Consolidated Balance Sheets. As of December 31, 2010, our equity method investees (Greenfield LP and

Whitby) had aggregate debt outstanding of $494 million. Based on our pro rata share of each of the investments, our share of such debt would be approximately $247 million. All such debt is non-recourse to us. See Note 5 of the Notes to Consolidated Financial Statements for additional information on our investments.

Guarantee Commitments — As part of our normal business operations, we enter into various agreements providing, or otherwise arranging, financial or performance assurance to third parties on behalf of our subsidiaries in the ordinary course of such subsidiaries' respective business. Such arrangements include guarantees, standby letters of credit and surety bonds for power and natural gas purchase and sale arrangements and contracts associated with the development, construction, operation and maintenance of our fleet of power plants. These arrangements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our primary commercial obligations as of December 31, 2010, are as follows (in millions):

	Amounts of Commitment Expiration per Period						
Guarantee Commitments	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total Amounts Committed**
Guarantee of subsidiary debt[1]	$ 78	$ 77	$ 72	$ 318	$ 36	$ 271	$ 852
Standby letters of credit[2][4]	601	91	—	—	—	19	711
Surety bonds[3][4][5]	—	—	—	—	—	5	5
Total	$ 679	$ 168	$ 72	$ 318	$ 36	$ 295	$ 1,568

(1) Represents Calpine Corporation guarantees of certain project debt, power plant capital leases and related interest. All guaranteed capital leases are recorded on our Consolidated Balance Sheets.

(2) The standby letters of credit disclosed above represent those disclosed in Note 6 of the Notes to Consolidated Financial Statements.

(3) The majority of surety bonds do not have expiration or cancellation dates.

(4) These are off balance sheet obligations.

(5) As of December 31, 2010, $4 million of cash collateral is outstanding related to these bonds.

Contractual Obligations — Our contractual obligations related to continuing operations as of December 31, 2010, are as follows (in millions):

	Total	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 Years**
Operating lease obligations[1]	$ 291	$ 43	$ 81	$ 60	$ 107
Purchase obligations:					
Turbine commitments	$ 82	$ 54	$ 28	$ —	$ —
Commodity purchase obligations[2]	4,883	699	903	689	2,592
Land leases	499	12	23	24	440
LTSA's	77	11	16	12	38
Cost to complete construction projects	414	186	228	—	—
Other purchase obligations[3]	1,920	102	220	216	1,382
Total purchase obligations[4]	$ 7,875	$1,064	$1,418	$ 941	$ 4,452
Debt[5]	$10,262	$ 138	$ 291	$1,825	$ 8,008
Other long-term liabilities:					
Interest payments on debt[5][6]	$ 5,223	$ 648	$1,326	$1,213	$ 2,036
Liability for uncertain tax positions	60	14	19	—	27
Interest rate swap agreement [6]	392	205	176	9	2
Total other long-term liabilities	$ 5,675	$ 867	$1,521	$1,222	$ 2,065

(1) Included in the total are future minimum payments for power plant operating leases and office and equipment leases. See Note 15 of the Notes to Consolidated Financial Statements for more information.

(2) The amounts presented here include contracts for the purchase, transportation, or storage of commodities accounted for as executory contracts and therefore not recognized as liabilities on our Consolidated Balance Sheet.

(3) The amounts presented here include water agreements, transmission agreements, parts supply agreements and other purchase obligations.

(4) The amounts included above for purchase obligations represent the minimum requirements under contract.

(5) A note payable totaling $64 million associated with the sale of the PG&E note receivable to a third party is excluded from debt for this purpose as it is a non-cash liability.

(6) Amounts are projected based upon interest rates at December 31, 2010.

Our Emergence from Chapter 11

We emerged from Chapter 11 on January 31, 2008. In connection with our emergence from Chapter 11, we authorized issuance of 485 million shares of reorganized Calpine Corporation common stock primarily for the discharge of liabilities subject to compromise, repayment of the Second Priority Debt and for various other administrative and other post-petition claims. We borrowed approximately $6.4 billion under our First Lien Facilities, which was used to repay the outstanding term loan balance of $3.9 billion (excluding the unused portion under the $1.0 billion revolver) under our DIP Facility. The remaining net proceeds of approximately $2.5 billion, together with cash on hand, were used to distribute approximately $4.1 billion for the cash payment obligations under our Plan of Reorganization including the repayment of a portion of the Second Priority Debt and the payment of administrative claims. Our historical financial performance during the pendency of our Chapter 11 cases and CCAA proceedings is likely not indicative of our future financial performance. See Note 18 of the Notes to Consolidated Financial Statements for further information regarding our emergence from Chapter 11.

Special Purpose Subsidiaries

Pursuant to applicable transaction agreements, we have established certain of our entities legally separate from Calpine and our other subsidiaries. In accordance with U.S. GAAP, we consolidate these entities. As of the date of filing this Report, these entities included: GEC Holdings, LLC, Gilroy Energy Center, LLC, Creed, Goose Haven, Calpine Gilroy Cogen, L.P., Calpine Gilroy 1, Inc., Calpine King City Cogen, LLC, Calpine Securities Company, L.P. (a parent company of Calpine King City Cogen, LLC), Calpine King City, LLC (an indirect parent company of Calpine Securities Company, L.P.), Russell City Energy Company, LLC and OMEC. The following disclosures are required under certain applicable agreements and pertain to some of these entities. The financial information provided below represents the assets and liabilities for some of the special purpose subsidiaries as reflected on our Consolidated Balance Sheets. These amounts may differ materially from the assets and liabilities for these entities that present individual financial statements on a stand-alone basis to their project lenders.

GEC, a wholly owned subsidiary of GEC Holdings, LLC, has been established as an entity with its existence separate from us and other subsidiaries of ours. On September 30, 2003, GEC completed an offering of $302 million of 4% senior secured notes due 2011. In connection with the issuance of the secured notes, we received funding on a third party preferred equity investment in GEC Holdings, LLC totaling $74 million. This preferred interest meets the criteria of a mandatorily redeemable financial instrument and has been classified as debt due to certain preferential distributions to the third party. The preferential distributions are due semi-annually beginning in March 2004 through September 2011 and total approximately $113 million over the eight-year period. As of December 31, 2010 and 2009, there was $14 million and $25 million, respectively, outstanding under the preferred interest.

A long-term PPA between CES and the California Department of Water Resources was acquired by GEC by means of a series of capital contributions by CES and certain of its affiliates and is an asset of GEC, and the secured notes and the preferred interest are liabilities of GEC, separate from the assets and liabilities of us and other subsidiaries of ours. In addition to the PPA and nine peaker power plants (including Creed and Goose Haven) owned directly or indirectly by GEC, GEC's assets include cash and a 100% equity interest in each of Creed and Goose Haven, each of which is a wholly owned subsidiary of GEC and a guarantor of the 4% senior secured notes due 2011 issued by GEC. Each of GEC, Creed and Goose Haven has been established as an entity with its existence separate from us and other subsidiaries of ours. Creed and Goose Haven each have assets consisting of a peaker power plant and other assets. The following table sets forth selected financial information of GEC as of December 31, 2010 (in millions):

	2010
Assets	$ 501
Liabilities	48

On December 4, 2003, we announced that we had sold to a group of institutional investors our right to receive payments from PG&E under an agreement between PG&E and Gilroy regarding the termination and buy-out of a standard offer contract between PG&E and Gilroy for $133 million in cash. Since the transaction did not satisfy the criteria for sales treatment in accordance with U.S. GAAP, it was recorded on our Consolidated Financial Statements as a secured financing, with a note payable of $133 million. The notes receivable balance and note payable balance are both reduced as PG&E makes payments to the buyers of the notes receivable. The $24 million difference between the $157 million net book value of the notes receivable at the transaction date and the $133 million cash received is recognized as additional interest expense over the repayment term. We will continue to record interest income over the repayment term, and interest expense will be accreted on the amortizing note payable balance.

Pursuant to the applicable transaction agreements, each of Gilroy and Calpine Gilroy 1, Inc. (the general partner of Gilroy), has been established as an entity with its existence separate from us and other subsidiaries of ours. The following table sets forth the assets and liabilities of Gilroy and Calpine Gilroy I, Inc. as of December 31, 2010 (in millions):

	2010
Assets	$ 397
Liabilities	79

On May 1, 2007, our indirect wholly owned subsidiary OMEC entered into a $377 million non-recourse project finance facility construction loan agreement, which converted to a term loan on November 13, 2009 and matures in April 2019. The following table sets forth the assets and liabilities of OMEC as of December 31, 2010 (in millions):

	2010
Assets	$ 514
Liabilities	432

RISK MANAGEMENT AND COMMODITY ACCOUNTING

Our hedging strategy focuses first on protecting our balance sheet, given our debt obligations, our committed capital expenditures and other obligations. Secondly, our hedge efforts attempt to maximize our risk adjusted Commodity Margin by leveraging our knowledge, experience and fundamental views on gas and power.

We actively seek to manage and limit the commodity risks of our portfolio, utilizing multiple strategies of buying and selling power, natural gas and Heat Rate transactions to manage our Spark Spread and products that manage geographic price differences (basis differential). We have approximately 364 MW of capacity from power plants where we purchase fuel oil to meet these generation requirements; however, we have not currently entered into any hedging or optimization transactions for our fuel oil requirements as we do not expect fuel oil requirements to be material to us, but may elect to do so in the future.

Along with our portfolio of hedging transactions, we enter into power and natural gas positions that often act as hedges to our asset portfolio, but do not qualify as hedges under hedge accounting guidelines, such as commodity options transactions and instruments that settle on power price to natural gas price relationships (Heat Rate swaps and options). While our selling and purchasing of power and natural gas is mostly physical in nature, we also engage in marketing, hedging and optimization activities, particularly in natural gas, that are financial in nature. We use derivative instruments, which include physical commodity contracts and financial commodity instruments such as OTC and exchange traded swaps, futures, options, forward agreements and instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) for the purchase and sale of power, natural gas, and emission allowances to manage commodity price risk and to maximize the risk-adjusted returns from our power and natural gas assets. We conduct these hedging and optimization activities within a structured risk management framework based on controls, policies and procedures. We monitor these activities through active and ongoing management and oversight, defined roles and responsibilities, and daily risk measurement and reporting. Additionally, we seek to manage the associated risks through diversification, by controlling position sizes, by using portfolio position limits, and by entering into offsetting positions that lock in a margin.

While we enter into these transactions primarily to provide us with improved price and price volatility transparency, as well as greater market access, which benefits our hedging activities, we also are exposed to commodity price movements (both profits and losses) in connection with these transactions. These positions are included in and subject to our consolidated risk management portfolio position limits and controls structure. Changes in fair value of commodity positions that do not qualify for either hedge accounting or the normal purchase normal sale exemption are recognized currently in earnings in mark-to-market activity within operating revenues in the case of power transactions, and within fuel and purchased energy expense, in the case of natural gas transactions. Our future hedged status, and marketing and optimization activities are subject to change as determined by our commercial operations group, Chief Risk Officer, Risk Management Committee of senior management and Board of Directors.

We have economically hedged a substantial portion of our generation and natural gas portfolio mostly through power and natural gas forward physical and financial transactions for 2011; however, we remain susceptible to significant price movements for 2012 and beyond. By entering into these transactions, we are able to economically hedge a portion of our Spark Spread at pre-determined generation and price levels. We use a combination of PPAs and other hedging instruments to manage our variability in future cash flows. As of December 31, 2010, the maximum length of our PPAs extends 22 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 2 and 15 years, respectively.

We have historically used interest swaps to adjust the mix between our fixed and variable rate debt. The majority of our interest rate swaps mature in years 2011 through 2012. To the extent eligible, our interest rate swaps have been designated as cash flow hedges, and changes in fair value are recorded in OCI to the extent they are effective. Holding all other factors constant, we estimate that a 10% decrease in interest rates would result in a change in the fair value of our interest rate swaps formerly hedging our First Lien Credit Facility term loans of approximately $(18) million.

During 2010, we repaid approximately $3.5 billion of our First Lien Credit Facility term loans, which had approximately $3.3 billion (notional amount) of interest rate swaps hedging the scheduled variable interest payments under the First Lien Credit Facility term loans, which resulted in the following:

- Upon repayment of the debt, we reclassified the historic unrealized losses of approximately $206 million deferred in AOCI into our income as a separate item described below.
- We performed an evaluation consistent with our risk management policy, and we determined that, based upon current market conditions, liquidation of these interest rate swaps was not economically beneficial, and we elected to retain and hold these interest rate swap positions.
- Additionally, during the fourth quarter, we determined that the variable interest payments remaining on our $1.2 billion of the First Lien Credit Facility term loans that remained outstanding were no longer considered probable to occur, and we de-designated the remaining portion of the interest rate swaps of approximately $1.0 billion (notional amount). At the time of de-designation, the historical unrealized loss was approximately $102 million, which remained in AOCI; however, all future changes in fair value after the de-designation date were recorded into income as a separate item as described below. As of December 31, 2010, approximately $91 million of this loss remained in AOCI.

The reclassification of unrealized losses from AOCI into income, realized swap settlements subsequent to the reclassification date and the changes in fair value subsequent to the reclassification date of the interest rate swaps formerly hedging our First Lien Credit Facility described above totaled approximately $247 million for the year ended December 31, 2010 and is presented separate from interest expense as (gain) loss on interest rate derivatives, net on our Consolidated Statement of Operations. Holding all other factors constant, we estimate that a 10% decrease in interest rates would result in a change in the fair value of our interest rate swaps formerly hedging our First Lien Credit Facility of approximately $(5) million.

On January 14, 2011, we repaid the remaining balance under the First Lien Credit Facility term loans with the proceeds received from the issuance of the 2023 First Lien Notes and the unrealized losses related to these interest swaps of approximately $91 million remaining in AOCI at December 31, 2010, were reclassified out of AOCI and into income as additional (gain) loss on interest rate derivatives, net in 2011.

Assuming constant December 31, 2010, power and natural gas prices and interest rates, we estimate that pre-tax net gains of $19 million would be reclassified from AOCI into earnings during the next 12 months as the hedged transactions settle; however, the actual amounts that will be reclassified will vary based on changes in natural gas and power prices as well as interest rates. Therefore, we are unable to predict what the actual reclassification from AOCI into earnings (positive or negative) will be for the next 12 months.

The primary factors affecting our market risk and the fair value of our derivatives at any point in time are the volume of open derivative positions (MMBtu, MWh and $ notional amounts); changing commodity market prices, principally for power and natural gas; our credit standing and that of our counterparties for energy commodity derivatives; and prevailing interest rates for our interest rate swaps. Since prices for power and natural gas and interest rates are volatile, there may be material changes in the fair value of our derivatives over time, driven both by price volatility and the changes in volume of open derivative transactions. Our derivative assets and (liabilities) have decreased to approximately $0.9 billion and $(1.1) billion at December 31, 2010, compared to $1.3 billion and $(1.6) billion at December 31, 2009, respectively. As of December 31, 2010, the fair value of our level 3 derivative assets and liabilities represent only a small portion of our total assets and liabilities (less than 1%). See Note 7 of the Notes to Consolidated Financial Statements for further information related to our level 3 derivative assets and liabilities.

The change in fair value of our outstanding commodity and interest rate derivative instruments from January 1, 2010, through December 31, 2010, is summarized in the table below (in millions):

	Interest Rate Swaps	Commodity Instruments	Total
Fair value of contracts outstanding at January 1, 2010	$ (319)	$ 8	$ (311)
Items recognized or otherwise settled during the period[(1)(2)]	211	40	251
Fair value attributable to new contracts	2	(38)	(36)
Changes in fair value attributable to price movements	(258)	164	(94)
Changes in fair value attributable to nonperformance risk	(3)	—	(3)
Fair value of contracts outstanding at December 31, 2010[(3)]	$ (367)	$ 174	$ (193)

(1) Interest rate settlements consist of recognized losses from former interest rate cash flow hedges of $198 million that were de-designated as a result of repayment of the First Lien Credit Facility term loans and recognized losses from settlements of undesignated interest rate swaps of $13 million (represents a portion of interest expense and (gain) loss on interest rate derivatives, net as reported on our Consolidated Statements of Operations).

(2) Losses from settlement of cash flow hedges previously reflected in OCI of approximately $83 million partially offset by gains on settlement of commodity contracts not designated as hedging instruments of approximately $43 million (represents a portion of operating revenues and fuel and purchased energy expense as reported on our Consolidated Statements of Operations) and other changes in derivative assets and liabilities not reflected in OCI or net income.

(3) Net commodity and interest rate derivative assets and liabilities reported in Notes 7 and 8 of the Notes to Consolidated Financial Statements.

The change since the last balance sheet date in the total value of the derivatives (both assets and liabilities) is reflected either in cash for option premiums paid or collected, in OCI, net of tax for cash flow hedges, or on our Consolidated Statements of Operations as a component (gain or loss) in current earnings.

The following tables detail the components of our total mark-to-market activity for both the net realized gain (loss) and the net unrealized gain (loss) recognized from our derivative instruments not designated as hedging instruments and where these components were recorded on our Consolidated Statements of Operations for the years ended December 31, 2010, 2009 and 2008 (in millions):

	2010	2009	2008
Realized gain (loss)			
Interest rate swaps	$ (31)	$ (32)	$ (9)
Commodity derivative instruments[(1)]	114	37	(146)
Total realized gain (loss)	$ 83	$ 5	$ (155)
Unrealized gain (loss)[(2)]			
Interest rate swaps	$ (199)	$ 8	$ (11)
Commodity derivative instruments	143	79	35
Total unrealized gain (loss)	$ (56)	$ 87	$ 24
Total mark-to-market activity, net	$ 27	$ 92	$ (131)

(1) Balance includes a non-cash gain from amortization of prepaid power sales agreements of approximately $40 million for the year ended December 31, 2008.

(2) Changes in unrealized gains and losses include de-designation of interest rate swap cash flow hedges and related reclassification from AOCI into income, hedge ineffectiveness and adjustments to reflect changes in credit default risk exposure.

Realized and unrealized gain (loss)	2010	2009	2008
Power contracts included in operating revenues	$ (19)	$ 7	$ 232
Natural gas contracts included in fuel and purchased energy expense	276	109	(343)
Interest rate swaps included in interest expense	17	(24)	(20)
Gain (loss) on interest rate derivatives, net	(247)	—	—
Total mark-to-market activity, net	$ 27	$ 92	$ (131)

Our change in AOCI from an accumulated loss of $266 million at December 31, 2009, to an accumulated loss of $125 million at December 31, 2010, was primarily driven by reclassification adjustments for cash flow hedges realized in net income, unrealized losses on interest rate swaps hedging the First Lien Credit Facility term loans that were repaid during 2010 (see Note 6 for further discussion of issuances under First Lien Notes and repayment of the First Lien Credit Facility term loans) and a decrease in interest rates which were partially offset by decreases in commodity prices and the effect of income taxes, which includes a net $27 million tax expense in OCI with an offsetting benefit to continuing operations related to the intraperiod tax allocation provisions under U.S. GAAP.

Commodity Price Risk — Commodity price risks result from exposure to changes in spot prices, forward prices, price volatilities and correlations between the price of power, steam, natural gas and fuel oil. We manage the commodity price risk and the variability in future cash flows from forecasted sales of power and purchases of natural gas of our entire portfolio of generating assets and contractual positions by entering into various derivative and non-derivative instruments.

The net fair value of outstanding commodity derivative instruments at December 31, 2010, based on price source and the period during which the instruments will mature, are summarized in the table below (in millions):

Fair Value Source	2011	2012-2013	2014-2015	After 2015	Total
Prices actively quoted	$ 134	$ (23)	$ —	$ —	$ 111
Prices provided by other external sources	79	(21)	—	—	58
Prices based on models and other valuation methods	(10)	13	2	—	5
Total fair value	$ 203	$ (31)	$ 2	$ —	$ 174

We measure the commodity price risks in our portfolio on a daily basis using a VAR model to estimate the maximum potential one-day risk of loss based upon historical experience resulting from market movements in comparison to internally established thresholds. Our VAR is calculated for our entire portfolio which is comprised of commodity derivatives, power plants, PPAs, and other physical and financial transactions. The portfolio VAR calculation incorporates positions for the remaining portion of the current calendar year plus the following two calendar years. We measure VAR using a variance/covariance approach based on a confidence level of 95%, a one-day holding period, and actual observed historical correlation. While we believe that our VAR assumptions and approximations are reasonable, different assumptions and/or approximations could produce materially different estimates.

The table below presents the high, low and average of our daily VAR for the years ended December 31, 2010 and 2009 (in millions):

	2010	2009
Year ended December 31:		
High	$ 58	$ 59
Low	$ 20	$ 28
Average	$ 30	$ 47
As of December 31	$ 37	$ 51

Liquidity Risk — Liquidity risk arises from the general funding requirements needed to manage our activities and assets and liabilities. Increasing natural gas prices or Market Heat Rates can cause increased collateral requirements. Our liquidity management framework is intended to maximize liquidity access and minimize funding costs during times of rising prices. See further discussion regarding our uses of collateral as they relate to our commodity procurement and risk management activities in Note 9 of the Notes to Consolidated Financial Statements.

Credit Risk — Credit risk relates to the risk of loss resulting from non-performance or non-payment by our counterparties related to their contractual obligations with us. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We also have credit risk if counterparties are unable to provide collateral or post margin. We monitor and manage our credit risk through credit policies that include:

- credit approvals;
- routine monitoring of counterparties' credit limits and their overall credit ratings;
- limiting our marketing, hedging and optimization activities with high risk counterparties;
- margin, collateral, or prepayment arrangements; and
- payment netting arrangements, or master netting arrangements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty.

We believe that our credit policies adequately monitor and diversify our credit risk. We currently have no individual significant concentrations of credit risk to a single counterparty; however, a series of defaults or events of nonperformance by several of our individual counterparties could impact our liquidity and future results of operations. We monitor and manage our total comprehensive credit risk associated with all of our contracts and PPAs irrespective of whether they are accounted for as an executory contract, a normal purchase normal sale or whether they are marked-to-market and included in our derivative assets and liabilities on our Consolidated Balance Sheets. Our counterparty credit quality associated with the net fair value of outstanding commodity derivative instruments is included in our derivative assets and liabilities at December 31, 2010, and the period during which the instruments will mature are summarized in the table below (in millions):

Credit Quality (Based on Standard & Poor's Ratings as of December 31, 2010)	2011	2012-2013	2014-2015	After 2015	Total
Investment grade	$ 212	$ (28)	$ 2	$ —	$ 186
Non-investment grade	2	—	—	—	2
No external ratings	(11)	(3)	—	—	(14)
Total fair value	$ 203	$ (31)	$ 2	$ —	$ 174

The fair value of our interest rate swaps are validated based upon external quotes. Our interest rate swaps are with counterparties we believe are high quality institutions and do not believe that our interest rate swaps expose us to any significant credit risk. See further discussion of our interest rate swaps in the "— Interest Rate Risk" section below.

Interest Rate Risk — We are exposed to interest rate risk related to our variable rate debt. Interest rate risk represents the potential loss in earnings arising from adverse changes in market interest rates. Our variable rate financings are indexed to base rates, generally LIBOR.

The following table summarizes the contract terms as well as the fair values of our debt instruments exposed to interest rate risk as of December 31, 2010. All outstanding balances and fair market values are shown gross of applicable premium or discount, if any (in millions):

	2011	2012	2013	2014	2015	Thereafter	Total	Fair Value December 31, 2010
Debt by Maturity Date:								
Fixed Rate	$ 71	$ 21	$ 24	$ 21	$ 7	$ 5,801	$ 5,945	$ 5,989
Average Interest Rate	6.9%	9.6%	9.6%	9.4%	6.5%	7.6%		
Variable Rate	$ 42	$ 140	$ 56	$ 1,475	$ 275	$ 1,936	$ 3,924	$ 3,931
Average Interest Rate(1)	4.4%	4.1%	4.4%	4.8%	5.0%	6.7%		

(1) Projection based upon anticipated LIBOR rates.

APPLICATION OF CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with U.S. GAAP requires management to make certain estimates and assumptions which are inherently imprecise and may differ significantly from actual results achieved. We believe the following are our more critical accounting policies due to the significance, subjectivity and judgment involved in determining our estimates used in preparing our Consolidated Financial Statements. See Note 2 of the Notes to Consolidated Financial Statements for a discussion of the application of these and other accounting policies. We evaluate our estimates and assumptions used in preparing our Consolidated Financial Statements on an ongoing basis utilizing historic experience, anticipated future events or trends, consultation with third party advisors or other methods that involve judgment as determined appropriate under the circumstances. The resulting effects of changes in our estimates are recorded in our Consolidated Financial Statements in the period in which the facts and circumstances that give rise to the change in estimate become known.

Revenue Recognition

We routinely enter into physical commodity contracts for sales of our generated power to manage risk and capture the value inherent in our generation. Determining the proper accounting for our power contracts can require significant judgment and impact how we recognize revenue. In addition, we determine whether the contract should be accounted for on a gross or net basis. Determining the proper accounting treatment involves the evaluation of quantitative, as well as qualitative factors, to determine if the contract should be accounted for as one of the following:

- a contract that qualifies as a lease;
- a derivative;
- a contract that meets the definition of a derivative but is eligible for the normal purchase normal sale exemption; or
- a contract that is a physical or executory contract.

Lease Accounting — Contracts accounted for as operating leases, such as certain tolling agreements, with minimum lease rentals which vary over time must be levelized. Generally, we levelize these contract revenues on a straight-line basis over the term of the contract.

Executory and Physical Contracts Exempt from Derivative Accounting — We generally recognize revenue from the sale of power or host steam thermal energy for sale to our customers for use in industrial or other heating operations, upon transmission and delivery to the customer at the contractual price. In addition to revenues from power, host steam revenues and RECs from our Geysers Assets related to generation, our operating revenues also include:

- power and steam revenue consisting of fixed and variable capacity payments, including capacity payments received from PJM capacity auctions which are not related to generation;
- other revenues such as RMR Contracts, resource adequacy and certain ancillary service revenues; and
- other service revenues.

Capacity payments, RMR Contracts, RECs, resource adequacy and other ancillary revenues are recognized when contractually earned and consist of revenues received from our customers either at the market price or a contract price.

See " — Accounting for Derivative Instruments" directly below for a discussion of the significant judgments and estimates related to accounting for derivative instruments. We apply lease or accrual accounting to contracts that are exempt from derivative accounting or do not meet the definition of a derivative instrument.

Gross vs. Net Accounting — We determine whether the financial statement presentation of revenues should be on a gross or net basis. Where we act as principal, we record settlement of our physical commodity contracts on a gross basis. With respect to our physical executory contracts, where we do not take title of the commodities but receive a variable payment to convert natural gas into power and steam in a tolling operation, we record revenues on a net basis. Our physical commodity contracts are not entered into for the purpose of settling on a net basis with another counterparty.

Fair Value Measurements

We use fair value to measure certain of our assets, liabilities and expenses in our financial statements. Fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., the exit price). Generally, the determination of fair value requires the use of significant judgment and different approaches and models under varying circumstances. Under a market based approach, we consider prices of similar assets, consult with brokers and experts or employ other valuation techniques. Under an income based approach, we generally estimate future cash flows and then discount them at a risk adjusted rate.

Accordingly, the determination of fair value represents a critical accounting policy. Our most significant fair value measurements represent the valuation of our derivative assets and liabilities, which are measured on a recurring basis (each reporting period) and measurements of impairments and acquired assets on a nonrecurring basis. We primarily apply the market approach and income approach for recurring fair value measurements (primarily our derivative assets and liabilities) using the best available information. We primarily utilize the income approach for nonrecurring fair value measurements such as impairments of our assets as market prices for similar assets may not be readily available and may not incorporate the expected future returns from our assets. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observability of those inputs. U.S. GAAP establishes a fair value hierarchy which classifies fair value measurements from level 1 through level 3 based upon the inputs used to measure fair value:

Level 1 — Quoted prices (unadjusted) are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 — Pricing inputs include quoted prices for similar assets and liabilities in active markets, and inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

Level 3 — Pricing inputs include significant inputs that are generally less observable or from unobservable sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Derivative Instruments and Valuation Techniques

The primary factors affecting the fair value of our derivative instruments at any point in time are the volume of open derivative positions (MMBtu, MWh and $ notional amounts), changing commodity market prices, principally for power and natural gas, liquidity risk, counterparty and our credit risk and that of our counterparties for energy commodity derivatives; and prevailing interest rates for our changes in interest rates. Prices for power and natural gas and interest rates are volatile, which can result in material changes in the fair value measurements reported in our financial statements in the future. Derivative contracts can be exchange-traded or OTC. For OTC derivatives that trade in liquid markets, model inputs can generally be verified and model selection does not involve significant management judgment. Certain OTC derivatives trade in less liquid markets with limited pricing information, and the determination of fair value for these derivatives is inherently more difficult.

For our level 2 and level 3 derivative instruments, we utilize models to measure fair value. Where models are used, the selection of a particular model to value an asset or liability depends upon the contractual terms of, and specific risks, as well as the availability of pricing information in the market. We generally use similar models to value similar instruments. Valuation models require a variety of inputs, including contractual terms, market prices, yield curves, credit curves and measures of volatility. These models are primarily industry-standard models, including the Black-Scholes pricing model. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. In cases where there is no corroborating market information available to support significant model inputs, we initially use the transaction price as the best estimate of fair value.

Our derivative instruments that are traded on the NYMEX primarily consist of natural gas swaps, futures and options and are classified as level 1 fair value measurements.

Our derivative instruments that primarily consist of interest rate swaps and OTC power and natural gas forwards for which market-based pricing inputs are observable are classified as level 2 fair value measurements. Generally, we obtain our level 2 pricing inputs from markets such as the Intercontinental Exchange.

Our OTC power and natural gas forwards and options where pricing inputs are unobservable, as well as other complex and structured transactions are classified as level 3 fair value measurements. Complex or structured transactions are tailored to our or our customers' needs and can introduce the need for internally-developed model inputs which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in level 3. At each balance sheet date, we perform an analysis of all instruments subject to fair value measurement and include in level 3 all of those whose fair value is based on significant unobservable inputs.

The determination of fair value of our derivatives also includes consideration of our credit standing, the credit standing of our counterparties and the impact of credit enhancements, if any. We assess non-performance risk by adjusting the fair value of our derivatives based on the credit standing of the counterparties involved and the impact of credit enhancements, if any. Such valuation adjustments represent the amount of probable loss due to default either by us or a third party. Our credit valuation methodology is based on a quantitative approach which allocates a credit adjustment to the fair value of derivative transactions based on the net exposure of each counterparty. We develop our credit reserve based on our expectation of the market participants' perspective of potential credit exposure. Our calculation of the credit reserve on net asset positions is based on available market information including credit default swap rates, credit ratings and historical default information. We also incorporate non-performance risk in net liability positions based on an assessment of our potential risk of default.

Impairments

When we determine an impairment exists, we determine fair value using valuation techniques such as the present value of expected future cash flows. In order to estimate future cash flows, we consider historical cash flows, existing and future contracts and PPAs and changes in the market environment and other factors that may affect future cash flows. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our other earnings forecasts). Our forecasts generally assume that Commodity Margin will increase in future years in these regions as the supply and demand relationships improve. The use of this method involves inherent uncertainty. We use our best estimates in making these evaluations and consider various factors, including forward price curves for power and fuel costs and forecasted operating costs. However, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

We also discount the estimated future cash flows associated with the asset using a single interest rate representative of the risk involved with such an investment including contract terms, tenor and credit risk of counterparts. We may also consider prices of similar assets, consult with brokers, or employ other valuation techniques. We use our best estimates in making these evaluations; however, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

Acquisitions of Assets and Liabilities

U.S. GAAP requires that the purchase price for an acquisition, such as our Conectiv Acquisition, be assigned and allocated to the individual assets and liabilities based upon their fair value. Generally, the amount recorded in the financial statements for an acquisition is the purchase price (value of the consideration paid), but a purchase price that exceeds the fair value of the assets acquired will result in the recognition of goodwill. In addition to the potential for the recognition of goodwill, differing fair values will impact the allocations of the purchase price to the individual assets and liabilities and can impact the gross amount and classification of assets and liabilities recorded on our Consolidated Balance Sheet and can impact the timing and the amount of depreciation expense recorded in any given period. We utilize our best effort to make our determinations and review all information available including estimated future cash flows and prices of similar assets when making our best estimate. We also may hire independent appraisers to help us make this determination as we deem appropriate under the circumstances.

Accounting for Derivative Instruments

Significant judgment and estimates are used in the accounting for derivative assets and liabilities, which include contract interpretation and assumptions used in forecasting future generation and market expectations. Derivative instruments which qualify for and are designated under the normal purchase normal sale exemption are not recorded in our Consolidated Financial Statements until the physical transaction is settled. Derivative instruments which do not qualify for the normal purchase normal sale exemption are recorded at fair value as discussed above in "— Fair Value Measurements." Dependent upon whether a derivative instrument qualifies for, and whether we elect or do not elect, hedge accounting treatment can significantly impact the timing and classification of changes in fair value within our Consolidated Financial Statements as further discussed below.

Hedge Accounting — Revenues and expenses derived from derivative instruments that qualify for hedge accounting are recorded in the period and same financial statement line item as the hedged item. Hedge accounting requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. We present the cash flows from our derivatives in the same category as the item being hedged within operating activities on our Consolidated Statements of Cash Flows unless they contain an other-than-insignificant financing element in which case their cash flows are classified within financing activities.

Cash Flow Hedges — We report the effective portion of the unrealized gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument as a component of OCI and reclassify such gains and losses into earnings in the same period during which the hedged forecasted transaction affects earnings. Gains and losses due to ineffectiveness on commodity hedging instruments are included in unrealized mark-to-market gains and losses and are recognized currently in earnings as a component of operating revenues (for power contracts), fuel and purchased energy expense (for natural gas contracts) and interest expense (for interest rate swaps). If it is determined that the forecasted transaction is no longer probable of occurring, then hedge accounting will be discontinued prospectively. If the hedging instrument is terminated or de-designated prior to the occurrence of the hedged forecasted transaction, the gain or loss associated with the hedge instrument remains deferred in AOCI until such time as the forecasted transaction impacts earnings, or until it is determined that the forecasted transaction is probable of not occurring.

Derivatives Not Designated as Hedging Instruments — Along with our portfolio of hedging transactions, we enter into power, natural gas and interest rate transactions that primarily act as economic hedges to our asset and interest rate portfolio, but either do not qualify as hedges under hedge accounting guidelines or qualify under the hedge accounting guidelines and the hedge accounting designation has not been elected, such as commodity futures, forwards, options, fixed for floating swaps and instruments that settle on power price to natural gas price relationships (Heat Rate swaps and options). Changes in fair value of derivatives not designated as hedging instruments are recognized currently in earnings as a component of operating revenues (for power contracts and Heat Rate swaps and options), fuel and purchased energy expense (for natural gas contracts) and interest expense (for interest rate swaps except as discussed below).

During 2010, we repaid approximately $3.5 billion of our First Lien Credit Facility term loans, which had approximately $3.3 billion in notional amount of interest rate swaps that were formerly hedging our variable interest and accounted for as cash flow hedges. We performed an evaluation consistent with our risk management policy, where we determined that, based upon current market conditions, liquidation of these interest rate swaps was not economically beneficial, and we elected to retain and hold these interest rate swap positions. These interest rate swaps no longer qualify as cash flow hedges. Consistent with our cash flow hedge accounting policy above, we reclassified $206 million in unrealized losses that were deferred in AOCI into our income. Additionally, during the fourth quarter, we de-designated the remaining portion of the interest rate swaps of approximately $1.0 billion (notional amount) that were hedging the remaining $1.2 billion of the First Lien Credit Facility term loans that remained outstanding as we determined the hedged variable interest payments were no longer considered probable to occur. At the time of de-designation, the historical unrealized loss was approximately $102 million, which remained in AOCI; however, all future changes in fair value of the above interest rate swaps were recorded into income. The reclassification of unrealized losses from AOCI into income, realized swap settlements subsequent to the reclassification date and the changes in fair value subsequent to the reclassification date of the interest rate swaps formerly hedging our First Lien Credit Facility described above totaled approximately $247 million for the year ended December 31, 2010 and is presented separate from interest expense as (gain) loss on interest rate derivatives, net on our Consolidated Statement of Operations.

See Notes 7 and 8 of the Notes to Consolidated Financial Statements for further discussion of our derivative instruments and our interest rate swaps formerly hedging our First Lien Credit Facility term loans.

Accounting for VIEs and Financial Statement Consolidation Criteria

We consolidate all VIEs where we have determined that we are the primary beneficiary. We adopted the new accounting standards and disclosure requirements for VIEs as required under U.S. GAAP effective January 1, 2010. The new standards and disclosure requirements replaced our previous accounting policy, which was a quantitative-based risks and rewards calculation for determining which enterprise, if any, is the primary beneficiary of a VIE to a more qualitative assessment with an approach focused on identifying which enterprise has both the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or receive benefits from the VIE.

In addition, the new standards and disclosure requirements include:

- A requirement to perform an analysis upon implementation of whether we are the primary beneficiary of our VIEs.
- A requirement to perform ongoing reassessments each reporting period of whether we are the primary beneficiary of our VIEs.
- Disclosure provisions to present separately on the face of the statement of financial position the significant assets of a consolidated VIE that can be used only to settle obligations of the consolidated VIE and the significant liabilities of a consolidated VIE for which creditors (or beneficial interest holders) do not have recourse to the general credit of the primary beneficiary.
- An additional reconsideration event for determining whether an entity is a VIE if any changes in facts and circumstances occur such that the holders of the equity investment at risk, as a group, lose the power from voting rights or similar rights of those investments to direct the activities of a VIE that most significantly impact the VIE's economic performance.

As required, we completed our analysis during the first quarter of 2010, and determined that we hold the power and rights to direct the most significant activities of all our wholly owned VIEs. As a result, we determined that the consolidation of OMEC was required effective January 1, 2010. See Notes 2 and 5 of the Notes to Consolidated Financial Statements for further discussion of our consolidation of OMEC and implementation of these new accounting standards.

Because we are required to perform ongoing reassessments each reporting period of whether we are the primary beneficiary, future changes in our assessments of whether we are the primary beneficiary each reporting period could require us to consolidate our VIEs that are currently not consolidated or deconsolidate our VIEs that are currently consolidated based upon our reassessments in future periods. Making these determinations can require the use of significant judgment to determine which variable interest holder has the power to direct the most significant activities of the VIE (the primary beneficiary) and can directly impact amounts reported in our future Consolidated Financial Statements.

Determination of the Primary Beneficiary

We consider the following primary activities which we believe to have a significant impact on a power plant's financial performance:

- operations and maintenance,
- plant dispatch, fuel strategy, and
- our ability to control or influence contracting and overall plant strategy.

We also base our determination on powers held as of the balance sheet date. Contractual terms that will apply in future periods, such as a purchase or sale option, are not considered in our analysis.

Additional Disclosure Requirements

The new accounting standards and disclosure requirements also require separate disclosure on the face of our Consolidated Balance Sheet of the significant assets of a consolidated VIE that can only be used to settle obligations of the consolidated VIE and the significant liabilities of a consolidated VIE for which creditors (or beneficial interest holders) do not have recourse to the general credit of the primary beneficiary separately.

Assets of our VIEs meet the separate disclosure criteria when Calpine Corporation is substantially limited or prohibited from access to assets (primarily cash and cash equivalents, restricted cash and property, plant and equipment), where the VIE is not a guarantor or grantor under our primary debt facilities (our First Lien Notes and Corporate Revolving Facility) and where there are prohibitions of the VIE under agreements that prohibit guaranteeing the debt of Calpine Corporation or its other subsidiaries and where the amounts were material to our financial statements. Liabilities of our VIEs meet the separate disclosure criteria, when our VIEs have project financing that prohibits the VIE from providing guarantees on the debt of others, where Calpine Corporation has not provided a corporate guarantee and where the amounts are material to our financial statements.

Unconsolidated VIEs

We have a 50% partnership interest in Greenfield LP and a 50% equity interest in Whitby where we do not have the power to direct the most significant activities of these entities and therefore do not consolidate them. Greenfield LP and Whitby are also VIEs. We account for these entities under the equity method of accounting and include our net equity interest in investments on our Consolidated Balance Sheets as we exercise significant influence over their operating and financial policies. During 2009 and 2008, we were not the primary beneficiary of OMEC and did not consolidate OMEC.

We hold a call option to purchase the Inland Empire Energy Center (a 775 MW natural gas-fired power plant located in California, which began commercial operations on May 3, 2010) from GE that may be exercised between years 7 and 14 after the start of commercial operation. GE holds a put option whereby they can require us to purchase the power plant, if certain plant performance criteria are met during year 15 after the start of commercial operation. We determined that we were not the primary beneficiary of the Inland Empire power plant, and we do not consolidate it due to the fact that GE directs the most significant activities of the power plant including operations and maintenance.

Long Lived Assets and Depreciation Expense

Determination of the appropriate depreciation method, proper useful lives and salvage values involves significant judgment, estimates, assumptions and historical experience. Changes in our estimates and methods can result in a significant impact in the amounts and timing of when we recognize depreciation expense and therefore significantly impact our financial condition and results of operations from period to period. Different depreciation methods can impact the timing and amount of depreciation expense affecting our results of operations and could result in different net book values of assets at a particular time during the useful life of the asset affecting our financial position. Estimates of useful lives also significantly impact the timing and amounts of depreciation expense and include significant estimates. If useful lives are too short, then the asset is depreciated too quickly and depreciation expense is overstated. Estimated useful lives can significantly decrease if routine maintenance or certain upgrades is not performed, premature mechanical failure of the asset occurs, significant increases in the planned level of usage occur, advances in technology make the asset obsolete, or if there are adverse changes in environmental regulations. Our depreciable cost basis of our assets are reduced by their estimated salvage values. Estimates involved with salvage values include future estimated costs of dismantlement and repair, market prices, environmental regulations and technological advancements. Dependent upon our ability to accurately estimate salvage values and the timing of disposal, the salvage values actually realized for our assets could significantly increase or decrease resulting in additional gains or losses in the year of disposal.

We depreciate our assets under the straight line method over the shorter of their estimated useful lives or lease term using an estimated salvage value which approximates 10% of the depreciable cost basis for our power plant assets where we own the land or have a favorable option to purchase the land at conclusion of the lease term and approximately 0.15% of the depreciable costs basis for our rotable equipment. We use component depreciation method for our rotable parts and composite depreciation method for all the other power plant asset groups and Geysers Assets. During 2009, we reviewed our accounting policies related to depreciation including our estimates of useful lives and salvage values. We determined changing from composite depreciation to component depreciation for our rotable natural gas-fired power plant assets, and changing our Geysers Assets depreciation from the units of production method to the straight line method was preferable under U.S. GAAP. In addition, we completed a depreciable life study of our natural gas-fired power plants and Geysers Assets and determined that a change in the depreciable lives of our natural gas-fired power plants and Geysers Assets was appropriate. See Note 4 of the Notes to Consolidated Financial Statements for further discussion regarding our changes in depreciation.

Impairments

We evaluate our long-lived assets, such as property, plant and equipment, equity method investments, turbine equipment and specifically identified intangibles, on an annual basis or when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Examples of such events or changes in circumstances are:

- a significant decrease in the market price of a long-lived asset;
- a significant adverse change in the manner an asset is being used or its physical condition;
- an adverse action by a regulator or legislature or an adverse change in the business climate;
- an accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset;
- a current-period loss combined with a history of losses or the projection of future losses; or
- a change in our intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

When we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities for long-lived assets that are expected to be held and used. If we determine that the undiscounted cash flows from an asset to be held and used are less than the carrying amount of the asset, or if we have classified an asset as held for sale, we must estimate fair value to determine the amount of any impairment loss. Significant judgment is required in determining fair value as discussed above in "— *Fair Value Measurements*." Equipment assigned to each power plant is not evaluated for impairment separately; instead, we evaluate our operating power plants and related equipment as a whole unit.

All construction and development projects are reviewed for impairment whenever there is an indication of potential reduction in fair value. If it is determined that it is no longer probable that the projects will be completed and all capitalized costs recovered through future operations, the carrying values of the projects would be written down to their fair value. When we determine that our assets meet the assets held-for-sale criteria, they are reported at the lower of the carrying amount or fair value less the cost to sell. We are also required to evaluate our equity method investments to determine whether or not they are impaired when the value is considered an "other than a temporary" decline in value.

See Note 2 of the Notes to Consolidated Financial Statements for further discussion of our impairment evaluation of long-lived assets.

Accounting for Income Taxes

To arrive at our consolidated income tax provision and other tax balances, significant judgment and estimates are required. Although we believe that our estimates are reasonable, no assurance can be given that the final tax outcome of these matters will not be different than that which is reflected in our historical tax provisions and accruals. Such differences could have a material impact on our income tax provision, other tax accounts and net income in the period in which such determination is made.

Our federal income tax reporting group is comprised primarily of two groups, CCFC and its subsidiaries, which we refer to as the CCFC group, and Calpine Corporation and its subsidiaries other than CCFC, which we refer to as the Calpine group. In 2005, CCFCP issued the CCFCP Preferred Shares, which resulted in the deconsolidation of the CCFC group for income tax purposes. On July 1, 2009, the CCFCP Preferred Shares were redeemed; however, CCFCP continues to be a partnership and therefore, the CCFC group remains deconsolidated from Calpine Corporation for federal income tax reporting purposes. In 2011, we may elect to consolidate our CCFC group with our Calpine group for federal income tax purposes. If we elect to consolidate our tax reporting groups, it is reasonably possible that the reversal of the CCFC group deferred tax liabilities will allow us to realize more of our Calpine group NOLs, thereby reducing the required valuation allowance. Although this election would not significantly impact our current tax payments, the result could have a significant impact on our reported tax expense in 2011. See Note 10 of the Notes to Consolidated Financial Statements for additional discussion of our Calpine and CCFC groups.

We have significant NOLs that will provide future tax deductions when we generate sufficient income during the applicable carryover periods. As of December 31, 2010, our consolidated federal NOLs totaled approximately $7.4 billion, which consisted of approximately $6.9 billion from the Calpine group and approximately $472 million from the CCFC group. The Calpine group has recorded a valuation allowance against the deferred tax assets for a majority of their NOLs as we determined it is more likely than not that they will expire unutilized. In 2011, we may elect to consolidate our CCFC group with our Calpine group for federal income tax purposes.

Under state income tax laws, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of the IRC. We are analyzing the effect of our change in ownership on the Effective Date for each of our significant states to determine the amount of our NOL limitation. The analysis will also determine our state NOLs expected to expire unutilized as a result of the cessation of business operations and changes in apportionment as of the Effective Date. Although our analysis is not complete, we believe that the statutory limitations on the use of some of our pre-emergence state NOLs will cause them to expire unutilized. We believe our analysis could result in a significant reduction of available state NOLs, which had a full valuation allowance as of December 31, 2010 and 2009. Upon completion, of the analysis, we will reduce our deferred tax asset for state NOLs that we are unable to utilize and make an equal reduction in our valuation allowance. The result should not have an effect on our income tax expense in 2011.

In the ordinary course of business, there are many transactions and calculations where the ultimate tax outcome is uncertain. Some of these uncertainties arise as a consequence of the treatment of capital assets, financing transactions, multistate taxation of operations and segregation of foreign and domestic income and expense to avoid double taxation. We recognize the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination. A tax position that meets the more-likely-than-not recognition threshold is measured as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement with a taxing authority. We reverse a previously recognized tax position in the first period in which it is no longer more likely than not that the tax position would be sustained upon examination. The determination and calculation of uncertain tax positions involves significant judgment in the application of complex tax laws. Resolution of these uncertainties in a manner inconsistent with our expectations could have a material impact on our financial condition or results of operations. As of December 31, 2010, we had $88 million of unrecognized tax benefits from uncertain tax positions.

See Note 10 of the Notes to Consolidated Financial Statements for further discussion of our accounting for income taxes.

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

The information required hereunder is set forth under Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Management and Commodity Accounting."

Item 8. ***Financial Statements and Supplementary Data***

The information required hereunder is set forth under "Report of Independent Registered Public Accounting Firm," "Consolidated Balance Sheets," "Consolidated Statements of Operations," "Consolidated Statements of Comprehensive Income (Loss) and Stockholders' Equity (Deficit)," "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***

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required financial disclosure.

As of the end of the period covered by this Report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Exchange Act. Based upon, and as of the date of, this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were effective such that the information relating to our Company, including our consolidated subsidiaries, required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP.

Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

Management has assessed the effectiveness of our internal control over financial reporting as of December 31, 2010. In making its assessment of internal control over financial reporting, management used the criteria described in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on management's assessment, we have concluded that our internal control over financial reporting was effective as of December 31, 2010.

The effectiveness of our internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of 2010, there were no changes in our internal control over financial reporting that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information*

On February 14, 2011, our Board of Directors appointed William E. ("Bill") Oberndorf to serve as a member of the Nominating and Governance Committee. As previously announced by us, Mr. Oberndorf was appointed by the Board effective January 1, 2011, to serve as a member of the Board until the next regularly scheduled annual election of directors at the 2011 annual meeting of stockholders to be held on May 11, 2011.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

Identification of Executive Officers

Set forth in the table below is a list of our executive officers, together with certain biographical information, including their ages as of the date of this Report:

Name	Age	Principal Occupation
Jack A. Fusco	48	President and Chief Executive Officer
John B. Hill	43	Executive Vice President and Chief Operating Officer
Zamir Rauf	51	Executive Vice President and Chief Financial Officer
W. Thaddeus Miller	60	Executive Vice President, Chief Legal Officer and Secretary
Jim D. Deidiker	55	Senior Vice President and Chief Accounting Officer
Gary M. Germeroth	52	Executive Vice President and Chief Risk Officer

Jack A. Fusco has served as our President and Chief Executive Officer and as a member of our Board of Directors since August 10, 2008. From July 2004 to February 2006, Mr. Fusco served as the Chairman and Chief Executive Officer of Texas Genco LLC. From 2002 through July 2004, Mr. Fusco was an exclusive energy investment advisor for Texas Pacific Group. From November 1998 until February 2002, Mr. Fusco served as President and Chief Executive Officer of Orion Power Holdings, Inc. Prior to joining Orion Power Holdings, Inc., Mr. Fusco was a Vice President at Goldman Sachs Power, an affiliate of Goldman, Sachs & Co. Prior to joining Goldman Sachs Power, Mr. Fusco was Executive Director of International Development and Operations for Pacific Gas & Electric Company's non-regulated subsidiary PG&E Enterprises, Inc. Mr. Fusco obtained a Bachelor of Science degree in Mechanical Engineering from California State University, Sacramento. Mr. Fusco served as a director of Foster Wheeler Ltd., a global engineering and construction contractor and power equipment supplier, until February 2009 and Graphics Packaging Holdings, a paper and packaging company until 2008.

John B. (Thad) Hill has served as our Executive Vice President and Chief Operating Officer since November 3, 2010 and served as the Company's Executive Vice President and Chief Commercial Officer since joining the Company on September 1, 2008. Prior to joining the Company, Mr. Hill most recently served as Executive Vice President of NRG Energy, Inc. since February 2006 and President of NRG Texas LLC since December 2006. Prior to joining NRG Energy, Inc., Mr. Hill was Executive Vice President of Strategy and Business Development at Texas Genco LLC from 2005 to 2006. From 1995 to 2005, Mr. Hill was with Boston Consulting Group, Inc., where he rose to Partner and Managing Director and led the North American energy practice, serving companies in the power and gas sector with a focus on commercial and strategic issues. Mr. Hill received his Bachelor of Arts degree from Vanderbilt University and a Master of Business Administration degree from the Amos Tuck School of Dartmouth College.

Zamir Rauf has served as our Executive Vice President and Chief Financial Officer since December 17, 2008, after serving as Interim Chief Financial Officer from June 4, 2008. Previously, he served as our Senior Vice President, Finance and Treasurer from September 2007 until his appointment as Interim Chief Financial Officer. Since joining the Company in February 2000, Mr. Rauf has served as Manager, Finance from February 2000 to April 2001, Director, Finance from April 2001 to December 2002, Vice President, Finance from December 2002 to July 2005 and Senior Vice President, Finance from July 2005 to September 2007. Prior to joining the Company, Mr. Rauf held various accounting and finance roles with Enron North America and Dynegy Inc., as well as credit and lending roles with Comerica Bank. Mr. Rauf earned his Bachelor of Arts degree in Business and Commerce and Masters in Business Administration – Finance degree from the University of Houston.

W. Thaddeus Miller has served as our Executive Vice President, Chief Legal Officer and Secretary since August 12, 2008. Prior to joining the Company, Mr. Miller most recently served as Executive Vice President and Chief Legal Officer of Texas Genco LLC from December 14, 2004 until 2006. From 2002 to 2004, Mr. Miller was a consultant to Texas Pacific Group, a private equity firm. From 1999 to 2002, he served as Executive Vice President and Chief Legal Officer of Orion Power Holdings, Inc., an independent power producer. From 1994 to 1999, Mr. Miller was a Vice President of Goldman Sachs & Co., where he focused on wholesale electric and other energy commodity trading. Before joining Goldman Sachs & Co., Mr. Miller was a partner in a New York law firm. Mr. Miller earned his Bachelor of Science degree from the U.S. Merchant Marine Academy and his Juris Doctor degree from St. John's School of Law. In addition, Mr. Miller was an officer in the U.S. Coast Guard from 1973 through 1976.

Jim D. Deidiker has served as our Senior Vice President and Chief Accounting Officer since November 15, 2010. Mr. Deidiker served as the Company's Senior Vice President and Chief Accounting Officer since joining the Company in January 2008 until May 2010, when he resigned as the Company's Chief Accounting Officer due to health concerns, but remained an employee. Mr. Deidiker returned to his role as the Company's Senior Vice President and Chief Accounting Officer once his health concerns were resolved. Prior to joining the Company, Mr. Deidiker most recently served as Vice President and Controller of Texas Genco LLC from 2005 to 2006 where he was responsible for financial and public reporting as well as management of the accounting function. From 1998 to 2005, Mr. Deidiker served as Managing Director & Vice President, Administration of AEP Energy Services, Inc. where he was responsible for management of the accounting function, financial reporting, contract administration and risk management for the gas pipeline and trading segment of AEP Energy Services, Inc. Mr. Deidiker obtained a Bachelor of Science degree in Accounting from Southwest Missouri State University and a Master in Business Administration degree from the University of Houston. In addition, Mr. Deidiker is a Certified Public Accountant and Certified Management Accountant.

Gary M. Germeroth has served as our Executive Vice President and Chief Risk Officer since June 2007. Mr. Germeroth's responsibilities include maintaining oversight of our risk management framework and assuring that our complex risks are communicated and understood throughout the organization. Prior to joining the Company, Mr. Germeroth worked for PA Consulting Group, Inc. and its predecessor firm, Hagler Bailly Risk Advisors, since 1999. Prior to joining PA Consulting, Mr. Germeroth held a variety of controllership, risk control and treasury positions at various entities in his energy career. Mr. Germeroth has more than 30 years of experience in energy strategy and risk management, having directed a variety of commercial strategy, enterprise risk management and corporate restructuring projects for multiple companies. Mr. Germeroth has led efforts related to corporate governance, portfolio risk evaluation, operational risk management, strategic options analysis, management of portfolio capital requirements, organizational and business process design, transaction settlement and financial accounting. Mr. Germeroth obtained a Bachelor of Science degree in Finance from the University of Denver.

The remaining information required by this Item under the captions "Board Meeting and Board Committee Information," "Corporate Governance Matters" and "Proposal 1 — Election of Directors" is incorporated herein by reference to our proxy statement for the 2011 annual meeting of stockholders to be held on May 11, 2011.

Item 11. *Executive Compensation*

Information appearing under this Item is incorporated herein by reference to our proxy statement for the 2011 annual meeting of stockholders to be held May 11, 2011.

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

Information appearing under this Item is incorporated herein by reference to our proxy statement for the 2011 annual meeting of stockholders to be held May 11, 2011.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

Information appearing under this Item is incorporated herein by reference to our proxy statement for the 2011 annual meeting of stockholders to be held May 11, 2011.

Item 14. ***Principal Accounting Fees and Services***

Information appearing under this Item is incorporated herein by reference to our proxy statement for the 2011 annual meeting of stockholders to be held May 11, 2011.

PART IV

Item 15. *Exhibits, Financial Statement Schedule*

Exhibit Number	Description
2.1	Debtors' Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code (incorporated by reference to Exhibit 2.1 to Calpine's Current Report on Form 8-K filed with the SEC on December 27, 2007).
2.2	Findings of Fact, Conclusions of Law, and Order Confirming Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code (incorporated by reference to Exhibit 2.2 to Calpine's Current Report on Form 8-K filed with the SEC on December 27, 2007).
2.3	Purchase and Sale Agreement by and between Riverside Energy Center, LLC and Calpine Development Holdings, Inc., as Sellers and Public Service Company of Colorado, as Purchaser dated as of April 2, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed with the SEC on July 29, 2010).**, ††
2.4	Purchase Agreement by and among Pepco Holdings, Inc., Conectiv, LLC, Conectiv Energy Holding Company, LLC and New Development Holdings, LLC dated as of April 20, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on July 8, 2010).**
3.1	Amended and Restated Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3.1 to Calpine's Current Report on Form 8-K filed with the SEC on February 1, 2008).
3.2	Amended and Restated By-Laws of the Company (as amended through May 7, 2009) (incorporated by reference to Exhibit 3.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, filed with the SEC on July 31, 2009).
4.1	Indenture, dated as of September 30, 2003, among Gilroy Energy Center, LLC, each of Creed Energy Center, LLC and Goose Haven Energy Center, as guarantors, and Wilmington Trust Company, as trustee and collateral agent, including form of 4.00% senior secured notes due 2011 (incorporated by reference to Exhibit 4.6 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, filed with the SEC on November 13, 2003).
4.2	Third Priority Indenture, dated as of March 23, 2004, among Calpine Generating Company, LLC, CalGen Finance Corp. and Manufacturers and Traders Trust Company (as successor trustee to Wilmington Trust FSB), as trustee, including form of third priority secured floating rate notes due 2011 (incorporated by reference to Exhibit 4.21 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2003, filed with the SEC on March 25, 2004).
4.3	Indenture, dated May 19, 2009, among Calpine Construction Finance Company, L.P. and CCFC Finance Corp., the guarantors named therein, and Wilmington Trust Company, as trustee, including form of 8.00% senior secured notes due 2016 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on May 22, 2009).
4.4	Indenture, dated October 21, 2009, between the Company and Wilmington Trust Company, as trustee, including form of 7.25% senior secured notes due 2017 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on October 26, 2009).
4.5	Amended and Restated Indenture, dated May 25, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 8% Senior Secured Notes due 2019 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on May 25, 2010).
4.6	Indenture, dated July 23, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.875% Senior Secured Notes due 2020 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on July 23, 2010).

Exhibit Number	Description
4.7	Indenture, dated October 22, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.50% Senior Secured Notes due 2021 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on October 22, 2010).
4.8	Indenture, dated January 14, 2011, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.875% Senior Secured Notes due 2023 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on January 14 , 2011).
4.9	Registration Rights Agreement, dated January 31, 2008, among the Company and each Participating Shareholder named therein (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on February 6, 2008).
10.1	Financing Agreements.
10.1.1.1	Credit Agreement, dated as of January 31, 2008, among the Company, as borrower, Goldman Sachs Credit Partners L.P., Credit Suisse, Deutsche Bank Securities Inc. and Morgan Stanley Senior Funding, Inc., as co-documentation agents and as co-syndication agents, General Electric Capital Corporation, as sub-agent for the revolving lenders, Goldman Sachs Credit Partners L.P., as administrative agent and as collateral agent and each of the financial institutions from time to time party thereto (incorporated by reference to Exhibit 10.5 to Calpine's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2010 filed with the SEC on October 29, 2010). ††
10.1.1.2	First Amendment to Credit Agreement and Second Amendment to Collateral Agency and Intercreditor Agreement, dated as of August 20, 2009, among the Company, certain of the Company's subsidiaries as guarantors, the financial institutions party thereto as lenders and Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on August 26, 2009).
10.1.1.3	Guaranty and Collateral Agreement, dated as of January 31, 2008, made by the Company and certain of the Company's subsidiaries party thereto in favor of Goldman Sachs Credit Partners, L.P., as collateral agent (incorporated by reference to Exhibit 10.1.3 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 29, 2008).
10.1.1.4	Credit Agreement dated as of June 8, 2010, among New Development Holdings, LLC, as Borrower, The Lenders Party Hereto and Credit Suisse AG, as Administrative Agent and Collateral Agent; Credit Suisse Securities (USA) LLC, Citigroup Global Markets Inc., and Deutsche Bank Securities Inc., as Joint Bookrunners and Joint Lead Arrangers; Credit Suisse AG as Syndication Agent; Credit Suisse AG, Citibank, N.A., and Deutsche Bank Trust Company Americas as Co-Documentation Agents (incorporated by reference to Exhibit 10.6 to Calpine's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2010 filed with the SEC on October 29, 2010).
10.1.1.5	Credit Agreement, dated as of December 10, 2010, among Calpine Corporation, Goldman Sachs Bank USA, as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, the lenders party thereto and other parties thereto (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on December 13, 2010).
10.2	Management Contracts or Compensatory Plans or Arrangements.
10.2.1.1	Employment Agreement, dated August 10, 2008, between the Company and Jack A. Fusco (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on August 12, 2008).†

Exhibit Number	Description
10.2.1.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (Jack A. Fusco) (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on August 12, 2008).†
10.2.1.3	Non-Qualified Stock Option Agreement between the Company and Jack Fusco, dated August 11, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on August 17, 2010).†
10.2.2	Letter Agreement, dated December 17, 2008, between the Company and Zamir Rauf (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on December 19, 2008).†
10.2.3.1	Letter Agreement, dated September 1, 2008, between the Company and John B. Hill (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on September 4, 2008).†
10.2.3.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (John B. Hill) (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on September 4, 2008).†
10.2.3.3	Non-Qualified Stock Option Agreement between the Company and John B. (Thad) Hill, dated August 11, 2010 (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on August 17, 2010).†
10.2.3.4	Non-Qualified Stock Option Agreement between the Company and John B. (Thad) Hill, dated November 3, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on November 5, 2010).†
10.2.4.1	Employment Agreement, dated August 11, 2008, between the Company and W. Thaddeus Miller (incorporated by reference to Exhibit 10.2.7 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed with the SEC on November 7, 2008).†
10.2.4.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (Thaddeus Miller) (incorporated by reference to Exhibit 4.4 to Calpine's Registration Statement on Form S-8 (Registration No. 333-153860) filed with the SEC on October 6, 2008).†
10.2.4.3	Non-Qualified Stock Option Agreement between the Company and W. Thaddeus Miller, dated August 11, 2010 (incorporated by reference to Exhibit 10.3 to Calpine's Current Report on Form 8-K filed with the SEC on August 17, 2010).†
10.2.5	Calpine Corporation U.S. Severance Program.†
10.2.6	Calpine Corporation 2010 Calpine Incentive Plan (incorporated by reference to Exhibit 10.6 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed with the SEC on July 29, 2010).†
10.2.7	Calpine Corporation 2009 Calpine Incentive Plan (incorporated by reference to Exhibit 10.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 8, 2009).†
10.2.7.1	The Amended and Restated Calpine Corporation 2008 Equity Incentive Plan (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on November 5, 2010).†
10.2.7.2	Form of Non-Qualified Stock Option Agreement (Pursuant to the 2008 Equity Incentive Plan) (incorporated by reference to Exhibit 10.4.3 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†

Exhibit Number	Description
10.2.7.3	Form of Restricted Stock Agreement (Pursuant to the 2008 Equity Incentive Plan) (incorporated by reference to Exhibit 10.4.4 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.2.7.4	Director's Restricted Stock Unit Agreement (Pursuant to the 2008 Equity Incentive Plan) between the Company and Mr. William J. Patterson (incorporated by reference to Exhibit 10.4.6 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.2.7.5	Restricted Stock Unit Election Form between the Company and William J. Patterson (incorporated by reference to Exhibit 10.4.7 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.2.8	The Amended and Restated Calpine Corporation 2008 Director Incentive Plan (incorporated by reference to Appendix A to Calpine's Definitive Proxy Statement on Schedule 14A filed with the SEC on April 5, 2010).†
10.2.9	Calpine Corporation Change in Control and Severance Benefits Plan (incorporated by reference to Exhibit 10.2.10 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 25, 2010).†
10.2.10	Letter Agreement, dated December 30, 2008, between the Company and Jim D. Deidiker (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K fled with the SEC on January 8, 2009).†
10.2.11	Letter re Employment Offer, dated February 6, 2009, between the Company and Michael D. Rogers (incorporated by reference to Exhibit 10.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 7, 2009).†
18.1	Letter of preferability regarding change in accounting principle from PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm (incorporated by reference to Exhibit 18.1 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2009 filed with the SEC on February 25, 2010).
21.1	Subsidiaries of the Company.*
23.1	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.*
23.2	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.*
24.1	Power of Attorney of Officers and Directors of Calpine Corporation (set forth on the signature pages of this Report).*
31.1	Certification of the Chief Executive Officer Pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Certification of the Senior Vice President and Chief Financial Officer Pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32.1	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
101	The following financial statements from the Company's Annual Report on Form 10-K for the year ended December 31, 2010, filed with the Securities and Exchange Commission, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Operations, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Comprehensive Income (Loss) and Stockholders' Equity (Deficit) and (v) Notes to Condensed Consolidated Financial Statements, tagged as blocks of text.*

* Filed herewith.

† Management contract or compensatory plan or arrangement.

** Schedules omitted pursuant to Item 601(b)(2) of Regulation S-K. Calpine will furnish supplementally a copy of any omitted schedule to the SEC upon request.

†† Portions of this exhibit have been omitted pursuant to a request for confidential treatment under Rule 24b-2 under the Securities Exchange Act of 1934.

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/ ZAMIR RAUF

Zamir Rauf
Executive Vice President and Chief Financial Officer (principal financial officer)

Date: February 17, 2011

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENT: That the undersigned officers and directors of Calpine Corporation do hereby constitute and appoint W. Thaddeus Miller 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 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 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/ JACK A. FUSCO Jack A. Fusco	President, Chief Executive Officer and Director (principal executive officer)	February 17, 2011
/s/ ZAMIR RAUF Zamir Rauf	Executive Vice President and Chief Financial Officer (principal financial officer)	February 17, 2011
/s/ JIM D. DEIDIKER Jim D. Deidiker	Chief Accounting Officer (principal accounting officer)	February 17, 2011
/s/ FRANK CASSIDY Frank Cassidy	Director	February 17, 2011
/s/ ROBERT C. HINCKLEY Robert C. Hinckley	Director	February 17, 2011
/s/ DAVID C. MERRITT David C. Merritt	Director	February 17, 2011
/s/ W. BENJAMIN MORELAND W. Benjamin Moreland	Director	February 17, 2011
/s/ ROBERT MOSBACHER, JR. Robert Mosbacher, Jr.	Director	February 17, 2011
/s/ DENISE M. O'LEARY Denise M. O'Leary	Director	February 17, 2011
/s/ WILLIAM E. OBERNDORF William E. Oberndorf	Director	February 17, 2011
/s/ J. STUART RYAN J. Stuart Ryan	Director	February 17, 2011

CALPINE CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2010

Report of Independent Registered Public Accounting Firm

To the Board of Directors
and Stockholders of Calpine Corporation

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)-1 present fairly, in all material respects, the financial position of Calpine Corporation and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)-2 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As described in Note 5 to the consolidated financial statements, the Company changed the manner in which it accounts for variable interest entities in 2010. As described in Note 4 to the consolidated financial statements, the Company changed its method of depreciation for certain of its property, plant and equipment assets in 2009.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 17, 2011

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2010, 2009 and 2008
(in millions, except share and per share amounts)

	2010	2009	2008
Operating revenues	$ 6,545	$ 6,463	$ 9,837
Operating expenses:			
Fuel and purchased energy expense	3,974	3,897	7,281
Plant operating expense	868	868	890
Depreciation and amortization expense	570	456	428
Sales, general and other administrative expense	151	174	203
Other operating expense	100	101	126
Total operating expenses	5,663	5,496	8,928
Impairment losses	116	4	46
(Gain) on sale of assets, net	(119)	—	—
(Income) loss from unconsolidated investments in power plants	(16)	(50)	229
Income from operations	901	1,013	634
Interest expense	789	815	1,044
(Gain) loss on interest rate derivatives, net	247	—	—
Interest (income)	(11)	(16)	(46)
Debt extinguishment costs	91	76	6
Other (income) expense, net	15	14	15
Income (loss) before reorganization items, income taxes and discontinued operations	(230)	124	(385)
Reorganization items	—	(1)	(302)
Income (loss) before income taxes and discontinued operations	(230)	125	(83)
Income tax expense (benefit)	(68)	15	(56)
Income (loss) before discontinued operations	(162)	110	(27)
Discontinued operations, net of tax expense	193	35	36
Net income	31	145	9
Net loss attributable to the noncontrolling interest	—	4	1
Net income attributable to Calpine	$ 31	$ 149	$ 10
Basic earnings (loss) per common share attributable to Calpine:			
Weighted average shares of common stock outstanding (in thousands)	486,044	485,659	485,054
Income (loss) before discontinued operations attributable to Calpine	$ (0.33)	$ 0.24	$ (0.05)
Discontinued operations, net of tax expense, attributable to Calpine	0.39	0.07	0.07
Net income per common share attributable to Calpine — basic	$ 0.06	$ 0.31	$ 0.02
Diluted earnings (loss) per common share attributable to Calpine:			
Weighted average shares of common stock outstanding (in thousands)	487,294	486,319	485,546
Income (loss) before discontinued operations attributable to Calpine	$ (0.33)	$ 0.24	$ (0.05)
Discontinued operations, net of tax expense, attributable to Calpine	0.39	0.07	0.07
Net income per common share attributable to Calpine — diluted	$ 0.06	$ 0.31	$ 0.02

The accompanying notes are an integral part of these Consolidated Financial Statements.

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
December 31, 2010 and 2009
(in millions, except share and per share amounts)

	2010	2009
ASSETS		
Current assets:		
Cash and cash equivalents ($345 and $264 attributable to VIEs.)	$ 1,327	$ 989
Accounts receivable, net of allowance of $2 and $14	669	750
Margin deposits and other prepaid expense	221	490
Restricted cash, current ($177 and $323 attributable to VIEs.)	195	508
Derivative assets, current	725	1,119
Inventory and other current assets	292	243
Total current assets	3,429	4,099
Property, plant and equipment, net ($6,602 and $5,327 attributable to VIEs.)	12,978	11,583
Restricted cash, net of current portion ($52 and $53 attributable to VIEs.)	53	54
Investments	80	214
Long-term derivative assets	170	127
Other assets	546	573
Total assets	$ 17,256	$ 16,650
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 514	$ 578
Accrued interest payable	132	54
Debt, current portion ($132 and $110 attributable to VIEs.)	152	463
Derivative liabilities, current	718	1,360
Income taxes payable	5	7
Other current liabilities	268	287
Total current liabilities	1,789	2,749
Debt, net of current portion ($4,069 and $3,048 attributable to VIEs.)	10,104	8,996
Deferred income tax liability, net of current	77	54
Long-term derivative liabilities	370	197
Other long-term liabilities	247	208
Total liabilities	12,587	12,204
Commitments and contingencies (see Note 15)		
Stockholders' equity:		
Preferred stock, $.001 par value per share; authorized 100,000,000 shares, none issued and outstanding at December 31, 2010 and 2009	—	—
Common stock, $.001 par value per share; authorized 1,400,000,000 shares, 444,883,356 shares issued and 444,435,198 shares outstanding at December 31, 2010, and 443,325,827 shares issued and 442,998,255 shares outstanding at December 31, 2009	1	1
Treasury stock, at cost, 448,158 and 327,572 shares, respectively	(5)	(3)
Additional paid-in capital	12,281	12,256
Accumulated deficit	(7,509)	(7,540)
Accumulated other comprehensive loss	(125)	(266)
Total Calpine stockholders' equity	4,643	4,448
Noncontrolling interest	26	(2)
Total stockholders' equity	4,669	4,446
Total liabilities and stockholders' equity	$ 17,256	$ 16,650

The accompanying notes are an integral part of these Consolidated Financial Statements.

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) AND STOCKHOLDERS' EQUITY (DEFICIT)
For the Years Ended December 31, 2010, 2009 and 2008
(in millions except share amounts)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Stockholders' Equity (Deficit)
Balance, December 31, 2007	$ 1	$ —	$ 3,263	$ (7,685)	$ (231)	$ 3	$ (4,649)
Cancellation of Calpine Corporation common stock	(1)	—	(3,263)	—	—	—	(3,264)
Issuance of reorganized Calpine Corporation common stock in accordance with our Plan of Reorganization	1	—	12,166	—	—	—	12,167
Treasury stock transactions	—	(1)	—	—	—	—	(1)
Stock-based compensation expense	—	—	50	—	—	—	50
Proceeds received from the exercise of warrants	—	—	1	—	—	—	1
Cumulative effect of adjustment from adoption of fair value measurement standards, net of tax of $8 million	—	—	—	(14)	—	—	(14)
Total stockholders' equity before comprehensive income (loss) items							4,290
Net income (loss)	—	—	—	10	—	(1)	9
Gain on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income	—	—	—	—	141	—	141
Reclassification adjustment for cash flow hedges realized in net income	—	—	—	—	27	—	27
Foreign currency translation loss	—	—	—	—	(19)	—	(19)
Income tax expense	—	—	—	—	(76)	—	(76)
Total comprehensive income							82
Balance, December 31, 2008	$ 1	$ (1)	$ 12,217	$ (7,689)	$ (158)	$ 2	$ 4,372
Treasury stock transactions	—	(2)	—	—	—	—	(2)
Stock-based compensation expense	—	—	38	—	—	—	38
Other	—	—	1	—	—	—	1
Total stockholders' equity before comprehensive income (loss) items							4,409
Net income (loss)	—	—	—	149	—	(4)	145
Gain on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income	—	—	—	—	180	—	180
Reclassification adjustment for cash flow hedges realized in net income	—	—	—	—	(335)	—	(335)
Foreign currency translation gain	—	—	—	—	4	—	4
Income tax benefit	—	—	—	—	43	—	43
Total comprehensive income							37
Balance, December 31, 2009	$ 1	$ (3)	$ 12,256	$ (7,540)	$ (266)	$ (2)	$ 4,446
Treasury stock transactions	—	(2)	—	—	—	—	(2)
Stock-based compensation expense	—	—	24	—	—	—	24
Other	—	—	1	—	—	28	29
Total stockholders' equity before comprehensive income (loss) items							4,497
Net income	—	—	—	31	—	—	31
Gain on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income	—	—	—	—	25	—	25
Reclassification adjustment for cash flow hedges realized in net income	—	—	—	—	141	—	141
Foreign currency translation gain	—	—	—	—	2	—	2
Income tax expense	—	—	—	—	(27)	—	(27)
Total comprehensive income							172
Balance, December 31, 2010	$ 1	$ (5)	$ 12,281	$ (7,509)	$ (125)	$ 26	$ 4,669

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, 2010, 2009 and 2008
(in millions)

	2010	2009	2008
Cash flows from operating activities:			
Net income	$ 31	$ 145	$ 9
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense(1)	615	556	544
Debt extinguishment costs	91	37	7
Deferred income taxes	(26)	16	27
Impairment loss	116	4	46
(Gain) loss on sale of power plants and other, net	(314)	37	(1)
Unrealized mark-to-market activities, net	56	(89)	(24)
(Income) loss from unconsolidated investments in power projects	(16)	(50)	229
Return on investment in unconsolidated subsidiaries	11	11	—
Stock-based compensation expense	24	38	50
Reorganization items	—	(6)	(359)
Other	1	6	16
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable	91	108	375
Derivative instruments	(52)	(118)	234
Other assets	277	235	(101)
Accounts payable, LSTC and accrued expenses	26	(19)	(215)
Other liabilities	(2)	(150)	(343)
Net cash provided by operating activities	929	761	494
Cash flows from investing activities:			
Purchases of property, plant and equipment	(369)	(179)	(143)
Proceeds from sale of power plants, interests and other	954	—	492
Purchase of Conectiv assets and BRSP, net of cash acquired	(1,680)	—	—
Cash acquired due to reconsolidation of OMEC	8	—	—
Cash acquired due to reconsolidation of Canadian Debtors and other deconsolidated foreign entities	—	—	64
Contributions to unconsolidated investments	—	(19)	(17)
Return of investment from unconsolidated investments	—	9	27
Settlement of non-hedging interest rate swaps	(69)	—	—
(Increase) decrease in restricted cash	322	(59)	78
Other	3	(2)	15
Net cash provided by (used in) investing activities	(831)	(250)	516
Cash flows from financing activities:			
Repayments of project financing, notes payable and other	(937)	(1,361)	(684)
Borrowings from project financing, notes payable and other	1,272	1,034	457
Borrowings under First Lien Facilities	—	—	4,248
Repayments on First Lien Credit Facilities	(3,477)	(785)	(1,475)
Repayments of Second Priority Debt	—	—	(3,672)
Contributions from noncontrolling interest holder	17	—	—
Issuance of First Lien Notes	3,491	—	—
Financing costs	(136)	(65)	(207)
Refund of financing costs	10	—	—
Derivative contracts classified as financing activities	—	—	64
Other	—	(2)	1
Net cash provided by (used in) financing activities	240	(1,179)	(1,268)
Net increase (decrease) in cash and cash equivalents	338	(668)	(258)
Cash and cash equivalents, beginning of period	989	1,657	1,915
Cash and cash equivalents, end of period	$ 1,327	$ 989	$ 1,657

The accompanying notes are an integral part of these Consolidated Financial Statements.

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)

(in millions)

	2010	2009	2008
Cash paid (received) during the period for:			
Interest, net of amounts capitalized	$ 635	$ 761	$ 1,060
Income taxes	$ 21	$ 7	$ 74
Reorganization items included in operating activities, net	$ —	$ 5	$ 120
Reorganization items included in investing activities, net	$ —	$ —	$ (418)
Supplemental disclosure of non-cash investing and financing activities:			
Settlement of commodity contract with project financing	$ —	$ 79	$ —
Change in capital expenditures included in accounts payable	$ 1	$ 6	$ 13
Liabilities assumed in BRSP acquisition	$ 85	$ —	$ —
Conversion of Project Debt to Noncontrolling Interest	$ 11	$ —	$ —
Issuance of First Lien Notes in exchange for First Lien Credit Facility term loans	$ —	$ 1,200	$ —
Amended Steamboat project debt	$ —	$ 448	$ —
Settlement of LSTC through issuance of reorganized Calpine Corporation common stock	$ —	$ —	$ 5,200
DIP Facility borrowings converted into exit financing under our First Lien Facilities	$ —	$ —	$ 3,872
Settlement of Convertible Senior Notes and Unsecured Senior Notes with reorganized Calpine Corporation common stock	$ —	$ —	$ 3,703

(1) Includes depreciation and amortization included in fuel and purchased energy expense, interest expense and discontinued operations on our Consolidated Statements of Operations.

The accompanying notes are an integral part of these Consolidated Financial Statements.

1. Organization and Operations

We are an independent wholesale power generation company engaged in the ownership and operation of natural gas-fired and geothermal power plants in North America. We have a significant presence in major competitive wholesale power markets in California, Texas and the Mid-Atlantic region of the U.S. We sell wholesale power, steam, regulatory capacity, renewable energy credits and ancillary services to our customers, including industrial companies, retail power providers, utilities, municipalities, independent electric system operators, marketers and others. We engage in the purchase of natural gas and fuel oil as fuel for our power plants and in related natural gas transportation and storage transactions, and in the purchase of electric transmission rights to deliver power to our customers. We also enter into natural gas and power physical and financial contracts to economically hedge our business risks and optimize our portfolio of power plants.

2. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Our Consolidated Financial Statements have been prepared in accordance with U.S. GAAP and include the accounts of all majority-owned subsidiaries that are not VIEs and all VIEs where we have determined we are the primary beneficiary. Intercompany transactions have been eliminated in consolidation.

Consolidation of OMEC — We were required by U.S. GAAP to adopt new accounting standards for VIEs which became effective January 1, 2010 that required us to perform an analysis to determine whether we should consolidate any of our previously unconsolidated VIEs or deconsolidate any of our previously consolidated VIEs. We completed our required analysis and determined that we are the primary beneficiary of OMEC. Accordingly, as required by U.S. GAAP, we consolidated OMEC effective January 1, 2010. The consolidation of OMEC on January 1, 2010 was accounted for using historical cost and resulted in the addition to our Consolidated Balance Sheet of approximately $8 million in cash and cash equivalents, $535 million in property, plant and equipment, net, $26 million in other current and non-current assets, $375 million in project debt and $50 million in other current and non-current liabilities, and the removal of $144 million representing our investment balance in OMEC. Our Consolidated Financial Statements as of December 31, 2009 and for the years ended December 31, 2009 and 2008 present our investment in OMEC's net assets, revenues and expenses under the equity method of accounting. We made no other changes to our group of subsidiaries that we consolidate as a result of the adoption of these new standards. See Note 5 for further discussion of accounting for our VIEs.

Other Consolidations/Deconsolidations — On February 8, 2008, the Canadian Effective Date, the Canadian Court ordered and declared that the CCAA proceedings were terminated and we reconsolidated the Canadian Debtors, which had been deconsolidated as of December 20, 2005 as a result of bankruptcy filings by the Canadian Debtors under the CCAA in the Canadian Court. The assets reconsolidated included various working capital items and a 50% ownership interest in Whitby, an equity method investment, which had been fully impaired upon deconsolidation. See Note 18 for a further discussion of our emergence from Chapter 11.

We deconsolidated RockGen in January 2008 and Auburndale in August 2008, and subsequently reconsolidated RockGen in December 2008. See Note 5 for further discussion of our VIEs.

Equity Method Investments — We use the equity method of accounting to record our net interests in VIEs where we have determined that we are not the primary beneficiary, which include Greenfield LP, a 50% partnership interest, and Whitby, a 50% equity interest. Our share of net income (loss) is calculated according to our equity ownership or according to the terms of the applicable partnership agreement. See Note 5 for further discussion of our VIEs and unconsolidated investments.

Reclassifications — Certain reclassifications have been made to our Consolidated Statements of Operations for the years ended December 31, 2009 and 2008 to conform to the current year presentation. Our reclassifications are summarized as follows:

- We have reclassified depreciation expense on corporate assets previously recorded in sales, general and other administrative expense to depreciation and amortization expense of $9 million and $12 million for the years ended December 31, 2009 and 2008, respectively.
- We reclassified equipment, development project and other impairments previously recorded in other operating expense to impairment losses of nil and $13 million for the years ended December 31, 2009 and 2008, respectively.

Use of Estimates in Preparation of Financial Statements

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures included in our Consolidated Financial Statements. Actual results could differ from those estimates.

Fair Value of Financial Instruments and Derivatives

The carrying values of accounts receivable, accounts payable and other receivables and payables approximate their respective fair values due to their short-term maturities. See Note 6 for disclosures regarding the fair value of our debt instruments and Notes 7 and 8 for disclosures regarding the fair values of our derivative instruments.

Concentrations of Credit Risk

Financial instruments that potentially subject us to credit risk consist of cash and cash equivalents, restricted cash, accounts and notes receivable and derivative assets. Certain of our cash and cash equivalents, as well as our restricted cash balances, exceed FDIC insured limits or are invested in money market accounts with investment banks that are not FDIC insured. We place our cash and cash equivalents and restricted cash in what we believe to be credit-worthy financial institutions and certain of our money market accounts invest in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. Government, its agencies or instrumentalities. Additionally, we actively monitor the credit risk of our counterparties, including our receivable, commodity and derivative transactions. Our accounts and notes receivable are concentrated within entities engaged in the energy industry, mainly within the U.S. We generally have not collected collateral for accounts receivable from utilities and end-user customers; however, we may require collateral in the future. For financial and commodity derivative counterparties, we evaluate the net accounts receivable, accounts payable and fair value of commodity contracts and may require security deposits, cash margin or letters of credit to be posted if our exposure reaches a certain level or their credit rating declines.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. We have certain project finance facilities and lease agreements that require us to establish and maintain segregated cash accounts, which have been pledged as security in favor of the lenders under such project finance facilities, and the use of certain cash balances on deposit in such accounts is limited, at least temporarily, to the operations of the respective projects. At December 31, 2010 and 2009, we had cash and cash equivalents of $269 million and $264 million, respectively, that were subject to such project finance facilities and lease agreements.

Restricted Cash

Certain of our debt agreements, lease agreements or other operating agreements require us to establish and maintain segregated cash accounts, the use of which are restricted. These amounts are held by depository banks in order to comply with the contractual provisions requiring reserves for payments such as for debt service, rent, major maintenance and debt repurchases or with applicable regulatory requirements. Funds that can be used to satisfy obligations due during the next 12 months are classified as current restricted cash, with the remainder classified as non-current restricted cash. Restricted cash is generally invested in accounts earning market rates; therefore, the carrying value approximates fair value. Such cash is excluded from cash and cash equivalents on our Consolidated Balance Sheets and Statements of Cash Flows.

The table below represents the components of our restricted cash as of December 31, 2010 and 2009 (in millions):

	2010			2009		
	Current	Non-Current	Total	Current	Non-Current	Total
Debt service	$ 44	$ 25	$ 69	$ 193	$ 25	$ 218
Rent reserve	22	5	27	34	—	34
Construction/major maintenance	35	14	49	87	22	109
Security/project/insurance	75	7	82	146	—	146
Other	19	2	21	48	7	55
Total	$ 195	$ 53	$ 248	$ 508	$ 54	$ 562

Of our restricted cash at December 31, 2010 and 2009, $46 million and $292 million, respectively, relate to the assets of the following entities, each of which is an entity with its legal existence separate from us and our other subsidiaries (in millions):

	2010	2009
PCF	$ —	$ 159
Gilroy Energy Center, LLC	33	34
Rocky Mountain Energy Center, LLC	—	48
Riverside Energy Center, LLC	—	42
Calpine King City Cogen, LLC	13	8
PCF III	—	1
Total	$ 46	$ 292

Accounts Receivable and Payable

Accounts receivable and payable represent amounts due from customers and owed to vendors. Accounts receivable are recorded at invoiced amounts, net of reserves and allowances, and do not bear interest. Receivable balances greater than 30 days past due are individually reviewed for collectability, and if deemed uncollectible, are charged off against the allowance accounts after all means of collection have been exhausted and the potential for recovery is considered remote. We use our best estimate to determine the required allowance for doubtful accounts based on a variety of factors, including the length of time receivables are past due, economic trends and conditions affecting our customer base, significant one-time events and historical write-off experience. Specific provisions are recorded for individual receivables when we become aware of a customer's inability to meet its financial obligations. We review the adequacy of our reserves and allowances quarterly.

The accounts receivable and payable balances also include settled but unpaid amounts relating to marketing, hedging and optimization activities of CES. Some of these receivables and payables with individual counterparties are subject to master netting arrangements whereby we legally have a right of offset and we settle the balances net. However, for balance sheet presentation purposes and to be consistent with the way we present the majority of amounts related to marketing, hedging and optimization activities on our Consolidated Statements of Operations, we present our receivables and payables on a gross basis. We do not have any significant off balance sheet credit exposure related to our customers.

Counterparty Credit Risk

Our counterparties primarily consist of three categories of entities who participate in the wholesale energy markets:

- financial institutions and trading companies;
- regulated utilities, municipalities, cooperatives and other retail power suppliers; and
- oil, natural gas, chemical and other energy-related industrial companies.

We have exposure to trends within the energy industry, including declines in the creditworthiness of our counterparties for our commodity and derivative transactions. Currently, certain of our marketing counterparties within the energy industry have below investment grade credit ratings. Our risk control group manages counterparty credit risk and monitors our net exposure with each counterparty on a daily basis. The analysis is performed on a mark-to-market basis using forward curves. The net exposure is compared against a counterparty credit risk threshold which is determined based on each counterparty's credit rating and evaluation of their financial statements. We utilize these thresholds to determine the need for additional collateral or restriction of activity with the counterparty. We do not currently have any significant exposure to counterparties that are not paying on a current basis.

Inventory

At December 31, 2010 and 2009, we had inventory of $262 million and $209 million, respectively. Inventory primarily consists of spare parts, stored natural gas and fuel oil, emission reduction credits and natural gas exchange imbalances. Inventory, other than spare parts, is stated primarily at the lower of cost or market value under the weighted average cost method. Spare parts inventory is valued at weighted average cost and are expensed to plant operating expense or capitalized to property, plant and equipment as the parts are utilized and consumed.

Collateral

We use margin deposits, prepayments and letters of credit as credit support with and from our counterparties for commodity procurement and risk management activities. In addition, we have granted additional first priority liens on the assets currently subject to first priority liens under our First Lien Notes and Corporate Revolving Facility as collateral under certain of our power and natural gas agreements that qualify as "eligible commodity hedge agreements" under our Corporate Revolving Facility and certain of our interest rate swap agreements in order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to our counterparties under such agreements. The counterparties under such agreements would share the benefits of the collateral subject to such first priority liens ratably with the lenders under our First Lien Notes and Corporate Revolving Facility. See Note 9 for a further discussion on our amounts and use of collateral.

Deferred Financing Costs

Costs incurred related to the issuance of debt instruments are deferred and amortized over the term of the related debt using a method that approximates the effective interest rate method. However, when the timing of debt transactions involve contemporaneous exchanges of cash between us and the same creditor(s) in connection with the issuance of a new debt obligation and satisfaction of an existing debt obligation, deferred financing costs are accounted for depending on whether the transaction qualifies as an extinguishment or modification, which requires us to either write off the original deferred financing costs and capitalize the new issuance costs, or continue to amortize the original deferred financing costs and immediately expense the new issuance costs.

Property, Plant and Equipment, Net

Property, plant, and equipment items are recorded at cost. We capitalize costs incurred in connection with the construction of power plants, the development of geothermal properties and the refurbishment of major turbine generator equipment. When capital improvements to leased power plants meet our capitalization criteria they are capitalized as leasehold improvements and amortized over the shorter of the term of the lease or the economic life of the capital improvement. We expense maintenance when the service is performed for work that does not meet our capitalization criteria. Our current capital expenditures at our Geysers Assets are those incurred for proven reserves and reservoir replenishment (primarily water injection), pipeline and power generation assets and drilling of "development wells" as all drilling activity has been performed within the known boundaries of the steam reservoir. We have capitalized costs incurred during ownership consisting of additions, repairs or replacements when they appreciably extend the life, increase the capacity or improve the efficiency or safety of the property. Such costs are expensed when they do not meet the above criteria. We purchased our Geysers Assets as a proven steam reservoir and accounted for the assets under purchase accounting. All well costs, except well workovers, have been capitalized since our purchase date. Exploration activities are extremely limited and are not material to our overall capital expenditures or our fixed assets. We drilled one deep test well in the Glass Mountain area in northern California in 2001, which produced economically viable quantities of steam. Immaterial holding costs at Glass Mountain are expensed.

We depreciate our assets under the straight line method over the shorter of their estimated useful life or lease term using an estimated salvage value which approximates 10% of the depreciable cost basis for our power plant assets where we own the land or have a favorable option to purchase the land at conclusion of the lease term and approximately 0.15% of the depreciable costs basis for our rotable equipment. During 2009, we reviewed our accounting policies related to depreciation including our estimates of useful lives. We determined changing from composite depreciation to component depreciation for our rotable natural gas-fired power plant assets, and changing our Geysers Assets depreciation from the units of production method to the straight line method was preferable under U.S. GAAP. We also revised our estimates of useful lives. See Note 4 for further discussion regarding our changes in depreciation, changes in useful lives and the effective date of our changes.

Generally, upon normal retirement of assets under the composite depreciation method, the costs of such assets are retired against accumulated depreciation and no gain or loss is recorded. For the retirement of assets under the component depreciation method, generally, the costs and related accumulated depreciation of such assets are removed from our Consolidated Balance Sheets and a gain or loss is recorded as plant operating expense.

Impairment Evaluation of Long-Lived Assets (Including Intangibles and Investments)

We evaluate our long-lived assets, such as property, plant and equipment, equity method investments, turbine equipment patents and specifically identifiable intangibles for impairment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. When we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities for long-lived assets that are expected to be held and used. If we determine that the undiscounted cash flows from an asset to be held and used are less than the carrying amount of the asset, or if we have classified an asset as held for sale, we must estimate fair value to determine the amount of any impairment loss. Equipment assigned to each power plant is not evaluated for impairment separately; instead, we evaluate our operating power plants and related equipment as a whole unit. All construction and development projects are reviewed for impairment whenever there is an indication of potential reduction in fair value. If it is determined that a construction or development project is no longer probable of completion and the capitalized costs will not be recovered through future operations, the carrying value of the project will be written down to its fair value.

In order to estimate future cash flows, we consider historical cash flows, existing and future contracts and PPAs and changes in the market environment and other factors that may affect future cash flows. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our other earnings forecasts). The use of this method involves inherent uncertainty. We use our best estimates in making these evaluations and consider various factors, including forward price curves for power and fuel costs and forecasted operating costs. However, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

When we determine that our assets meet the assets held-for-sale criteria, they are reported at the lower of their carrying amount or fair value less the cost to sell. We are also required to evaluate our equity method investments to determine whether or not they are impaired when the value is considered an "other than a temporary" decline in value.

Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. We will also discount the estimated future cash flows associated with the asset using a single interest rate representative of the risk involved with such an investment including contract terms, tenor and credit risk of counterparts. We may also consider prices of similar assets, consult with brokers, or employ other valuation techniques. We use our best estimates in making these evaluations and consider various factors, including forward price curves for power and fuel costs and forecasted operating costs. However, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

The following table details impairment losses recorded during the years ended December 31, 2010, 2009 and 2008 (in millions):

	2010	2009	2008
Operating asset impairments(1)	$ 95	$ 4	$ 33
Impairment of equity method investment(2)	—	—	180
Equipment, development project and other impairment losses(1)	21	—	13
Total impairment losses	$ 116	$ 4	$ 226

(1) Amounts are included in impairment losses on our Consolidated Statements of Operations.

(2) Amounts are included in (income) loss from unconsolidated investments in power plants on our Consolidated Statements of Operations.

During 2010, we impaired approximately $95 million related to South Point (see Note 3 for further information related to our acquisition of the South Point lease and subsequent impairment of our South Point assets) and development costs of approximately $21 million associated with two development projects that originated prior to our Chapter 11 bankruptcy proceedings. We continued to market these projects after our Effective Date, but during 2010 we determined that their continued development was unlikely. During 2009, we wrote down our natural gas reserves by approximately $4 million based upon a sales agreement with a third party. During 2008, we recorded an impairment loss of $180 million as a result of the anticipated sale of our investment in Auburndale as further described in Note 5. An additional impairment loss of $33 million was recorded at December 31, 2008, for our Auburndale Peaking Energy Center (a separate power plant from Auburndale) which did not receive an expected contract renewal resulting in reduced future expected cash flows and we recorded impairments related to certain development projects that we determined were not probable of completion.

Asset Retirement Obligation

We record all known asset retirement obligations for which the liability's fair value can be reasonably estimated. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. At December 31, 2010 and 2009, our asset retirement obligation liabilities were $51 million and $48 million, respectively, primarily relating to land leases upon which our power plants are built and the requirement that the property meet specific conditions upon its return.

Revenue Recognition

Our operating revenues are composed of the following:

- power and steam revenue consisting of fixed and variable capacity payments, which are not related to generation including capacity payments received from PJM capacity auctions, variable payments, which are related to generation, host steam and RECs from our Geysers Assets, and other revenues such as RMR Contracts, resource adequacy and certain ancillary service revenues;

- realized and unrealized revenues from derivative instruments as a result of our marketing, hedging and optimization activities; and

- other service revenues.

Power and Steam

Physical Commodity Contracts — We recognize revenue primarily from the sale of power and steam thermal energy for sale to our customers for use in industrial or other heating operations upon transmission and delivery to the customer.

We routinely enter into physical commodity contracts for sales of our generated power to manage risk and capture the value inherent in our generation. Such contracts often meet the criteria of a derivative but are generally eligible for the normal purchase normal sale exemption. We apply lease or accrual accounting to these contracts that are exempt from derivative accounting or do not meet the definition of a derivative instrument. Certain other contracts do not meet the definition of a derivative and may be considered physical executory contracts or leases. Additionally, we determine whether the financial statement presentation of revenues should be on a gross or net basis.

With respect to our physical executory contracts, where we act as a principal, we take title of the commodities and assume the risks and rewards of ownership by receiving the natural gas and using the natural gas in our operations to generate and deliver the power. Where we act as principal, we record settlement of our physical commodity contracts on a gross basis. Where we do not take title of the commodities but receive a net variable payment to convert natural gas into power and steam in a tolling operation, we record the variable payment as revenue but do not record any fuel and purchased energy expense.

Capacity payments, RMR Contracts, RECs, resource adequacy and other ancillary revenues are recognized when contractually earned and consist of revenues received from our customers either at the market price or a contract price.

Leases — Contracts accounted for as operating leases, such as certain tolling agreements, with minimum lease rentals which vary over time must be levelized. Generally, we levelize these contract revenues on a straight-line basis over the term of the contract.

The total contractual future minimum lease receipts for these contracts are as follows (in millions):

2011	$ 235
2012	246
2013	224
2014	225
2015	227
Thereafter	965
Total	$ 2,122

Accounting for Derivative Instruments

We enter into a variety of derivative instruments including both exchange traded and OTC power and natural gas forwards, options as well as instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) and interest rate swaps. We recognize all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for the normal purchase normal sale exemption. Accounting for derivatives at fair value requires us to make estimates about future prices during periods for which price quotes are not available from sources external to us, in which case we rely on internally developed price estimates. See Note 8 for a further discussion on our accounting for derivatives.

Fuel and Purchased Energy Expense

Fuel and purchased energy expense is composed of the cost of natural gas and fuel oil purchased from third parties for the purposes of consumption in our power plants as fuel expense, and the cost of power and natural gas purchased from third parties for marketing, hedging and optimization activities as well as realized and unrealized mark-to-market gains and losses resulting from general market price movements against certain derivative natural gas contracts that do not qualify for hedge accounting treatment.

Plant Operating Expense

Plant operating expense primarily includes employee expenses, utilities, chemicals, repairs and maintenance, insurance and property taxes. We recognize these expenses when the service is performed or in the period in which the expense relates.

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying values of existing assets and liabilities and their respective tax basis and tax credit and NOL carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities due to a change in tax rates is recognized in income in the period that includes the enactment date.

We recognize the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination. A tax position that meets the more-likely-than-not recognition threshold is measured as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement with a taxing authority. We reverse a previously recognized tax position in the first period in which it is no longer more-likely-than-not that the tax position would be sustained upon examination. See Note 10 for a further discussion on our income taxes.

Earnings (Loss) per Share

Basic earnings (loss) per share is calculated using the weighted average shares outstanding during the period and includes restricted stock units for which no future service is required as a condition to the delivery of the underlying common stock. Diluted earnings (loss) per share is calculated by adjusting the weighted average shares outstanding by the dilutive effect of share-based awards using the treasury stock method. See Note 11 for a further discussion of our earnings (loss) per share.

Stock-Based Compensation

We use the Black-Scholes option-pricing model or the Monte Carlo simulation model to estimate the fair value of our employee stock options on the grant date. The Black-Scholes option-pricing model and the Monte Carlo simulation model take into account certain variables, which are further explained in Note 12.

Accounting for Reorganization

During the period December 20, 2005, through January 31, 2008, we conducted our business in the ordinary course as debtors-in-possession under the protection of the Bankruptcy Courts. We emerged from Chapter 11 on January 31, 2008. In accordance with financial reporting by entities in reorganization under the Bankruptcy Code prescribed by U.S. GAAP, certain income, expenses, realized gains and losses and provisions for losses that were realized or incurred in our Chapter 11 cases are recorded in reorganization items on our Consolidated Statements of Operations. See Note 18 for a further discussion on our emergence from Chapter 11.

New Accounting Standards and Disclosure Requirements

Consolidation of VIEs and Additional VIE Disclosures — Effective for interim and annual periods beginning after November 15, 2009, the Financial Accounting Standards Board amended the accounting standards for determining which enterprise is the primary beneficiary of a VIE, added additional VIE disclosure requirements and amended guidance for determining whether an entity is a VIE. The new standards generally replace the quantitative-based risks and rewards calculation for determining which enterprise, if any, is the primary beneficiary of a VIE to a more qualitative assessment with an approach focused on identifying which enterprise has the power to direct the activities of a VIE that most significantly impacts the VIE's economic performance and also has the obligation to absorb losses or receive benefits from the VIE. We completed our analysis during the first quarter of 2010, and determined that the consolidation of OMEC was required. See Note 5 for further discussion of implementation of these new accounting standards.

The new standards and disclosure requirements also added:

- A requirement to perform ongoing reassessments each reporting period of whether we are the primary beneficiary of our VIEs, which could require us to consolidate our VIEs that are currently not consolidated or deconsolidate our VIEs that are currently consolidated based upon our reassessments in future periods. No further changes to our determinations of whether we are the primary beneficiary of our VIEs were required for the year 2010.

- Disclosure provisions to present separately on the face of the statement of financial position the significant assets of a consolidated VIE that can be used only to settle obligations of the consolidated VIE and the significant liabilities of a consolidated VIE for which creditors (or beneficial interest holders) do not have recourse to the general credit of the primary beneficiary. Our Consolidated Balance Sheets include these required disclosures. The new standards also reduced required disclosures for consolidated VIEs without such restrictions if we are the equity holder and primary beneficiary.

- An additional reconsideration event for determining whether an entity is a VIE if any changes in facts and circumstances occur such that the holders of the equity investment at risk, as a group, lose the power from voting rights or similar rights of those investments to direct the activities of a VIE that most significantly impact the VIE's economic performance.

Fair Value Measurements and Disclosures — In January 2010, the Financial Accounting Standards Board issued Accounting Standards Update 2010-06, "Fair Value Measurements and Disclosures" to enhance disclosure requirements relating to different levels of assets and liabilities measured at fair value and to clarify certain existing disclosures. The update requires disclosure of transfers in and out of levels 1 and 2 and gross presentation of purchases, sales, issuances and settlements in the level 3 reconciliation of beginning and ending balances. The new disclosure requirements relating to level 3 activity are effective for interim and annual periods beginning after December 15, 2010 and all the other requirements are effective for interim and annual periods beginning after December 15, 2009. We adopted all of the disclosure requirements related to this update for the years ended December 31, 2010 and 2009. Since this update only required additional disclosures, adoption of this standard did not have a material impact on our results of operations, cash flows or financial condition. See Note 7 for disclosure of our fair value measurements in accordance with these disclosure requirements.

3. Acquisitions, Divestitures and Discontinued Operations

Conectiv Acquisition

On July 1, 2010, we, through our indirect, wholly owned subsidiary NDH, completed the Conectiv Acquisition. The assets acquired include 18 operating power plants and one plant under construction, with approximately 4,490 MW of capacity (including completion of the York Energy Center under construction and scheduled upgrades). We did not acquire Conectiv's trading book, load serving auction obligations or collateral requirements. Additionally, we did not assume any of Conectiv's off-site environmental liabilities, environmental remediation liabilities in excess of $10 million related to assets located in New Jersey that are subject to ISRA, or pre-close accumulated pension and retirement welfare liabilities; however, we assumed pension liabilities of approximately $6 million on future services and compensation increases for past services for 129 union employees who joined Calpine as a result of the Conectiv Acquisition. The net proceeds of $1.3 billion received from the NDH Project Debt were used, together with available operating cash, to pay the Conectiv Acquisition purchase price of approximately $1.64 billion and also fund a cash contribution from Calpine Corporation to NDH of $110 million to fund completion of the York Energy Center. See Note 6 for further discussion of the NDH Project Debt.

The Conectiv Acquisition provided us with a significant presence in the Mid-Atlantic market, one of the most robust competitive power markets in the U.S., and positioned us with three scale markets instead of two (California and Texas) giving us greater geographic diversity.

We accounted for the Conectiv Acquisition under the acquisition method of accounting in accordance with U.S. GAAP. During the year ended December 31, 2010, we expensed transaction and acquisition-related costs of approximately $36 million, of which, $26 million were included in sales, general and other administrative expense, and $10 million was included in plant operating expense on our Consolidated Statement of Operations.

The following table summarizes the consideration transferred for the Conectiv Acquisition and the preliminary values we assigned to the net assets acquired (in millions). The amounts below include revisions to the unrecorded and preliminary appraised values as presented in our September 30, 2010 Form 10-Q. Our preliminary values assigned below are still subject to finalization of environmental site investigation/remediation reports and other adjustments. Our depreciation expense included for the six months ended December 31, 2010, on the assets we obtained in the Conectiv Acquisition is based upon the preliminary values assigned below and represents our best estimate. Future changes, if any, to the values assigned could change our estimates of our depreciation expense in future periods; however, such changes, if any, are not expected to be material. We do not anticipate any significant goodwill will be recognized as a result of this acquisition.

Consideration	$ 1,640
Preliminary values of identifiable assets acquired and liabilities assumed:	
Assets:	
Current assets	$ 79
Property, plant and equipment, net	1,570
Other long-term assets	85
Total assets acquired	1,734
Liabilities:	
Current liabilities	46
Long-term liabilities	48
Total liabilities assumed	94
Net assets acquired	$ 1,640

During the last six months of 2010, the Conectiv Acquisition contributed $397 million in operating revenues and $73 million net income attributable to Calpine included in our Consolidated Statement of Operations.

The following table summarizes the pro forma operating revenues and net income (loss) attributable to Calpine for the periods presented as if the Conectiv Acquisition had occurred on January 1, 2009. The pro forma information has been prepared by adding the preliminary, unaudited historical results of Conectiv, as adjusted for depreciation expense (utilizing the preliminary values assigned to the net assets acquired from Conectiv disclosed above), interest expense from our NDH Project Debt and income taxes to our historical results for the periods indicated below (in millions, except per share amounts).

	2010	2009
Operating revenues	$ 7,931	$ 8,633
Net income (loss) attributable to Calpine	$ (83)	$ 71
Basic earnings (loss) per common share attributable to Calpine	$ (0.17)	$ 0.15
Diluted earnings (loss) per common share attributable to Calpine	$ (0.17)	$ 0.15

Acquisition of Broad River and South Point Leases

On December 8, 2010, we, through our wholly owned, indirect subsidiary, Calpine BRSP, purchased entities from CIT Capital USA Inc. that held the leases for our Broad River and South Point power plants by assuming debt with a fair value of approximately $297 million and a cash payment of approximately $40 million. Prior to this purchase, our Broad River power plant was operated under a sale-leaseback transaction that was accounted for as a failed sale-leaseback financing transaction and our South Point power plant was accounted for as an operating lease. The purchase of the entities holding the power plant leases only added an incremental $85 million in consolidated debt, as the transaction eliminated approximately $212 million recorded as debt and accrued interest owed to CIT Capital USA Inc. under our Broad River power plant lease.

We recorded a total pre-tax loss of approximately $125 million on our Consolidated Statement of Operations for the year ended December 31, 2010 for this transaction, which was recorded as shown below (in millions):

Broad River: debt extinguishment costs	$ 30
South Point: impairment loss	95
Total loss recorded for this transaction	$ 125

Broad River — Prior to the purchase, we operated the Broad River power plant under a lease that was accounted for as a failed sale-leaseback financing transaction under U.S. GAAP. The lease liability was included in project financing, notes payable and other debt balance and the power plant assets were included in our property plant and equipment. As a result of the purchase, we did not adjust the historical value of the assets. We allocated the value of the consideration paid in the transaction based upon the fair value of both plants, and the result was an allocation of assumed debt that was greater than the prior debt obligation resulting in a pre-tax loss of approximately $30 million. Because we primarily exchanged future lease obligations for a debt obligation, the resulting loss is recorded as debt extinguishment costs for accounting purposes.

South Point — Prior to the purchase, we accounted for the South Point lease as an operating lease. We allocated the consideration paid in the transaction based upon the fair value of both plants. The result was an allocation of consideration paid for South Point that was in excess of the fair value of assets acquired by approximately $95 million, which was primarily due to the elimination of a lease levelization asset associated with the prior lease, which was no longer proper on a consolidated basis. The resulting loss has been reported as an impairment loss for accounting purposes.

While the transaction resulted in a one-time, pre-tax loss, in the longer-term, the acquisition of these entities grants us greater flexibility and more control of the future operation of both plants and simplified a previously complex leasing arrangement.

Sale of Blue Spruce and Rocky Mountain

On December 6, 2010, we, through our wholly owned subsidiaries Riverside Energy Center, LLC and Calpine Development Holdings, Inc., completed the sale of our 100% ownership interests in Blue Spruce and Rocky Mountain to PSCo for approximately $739 million, subject to certain working capital adjustments at closing. Both power plants provided power and capacity to PSCo under PPAs, which materially expire in 2013 and 2014. The sale removed the restrictions on approximately $78 million in restricted cash at closing. We used the sales proceeds received and the approximately $78 million in restricted cash described above to repay project debt of approximately $418 million, for general corporate purposes, to strengthen our balance sheet and to focus more resources on our core markets. We recorded a pre-tax gain of approximately $209 million upon closing this transaction. The results of operations and the gain on sale of Blue Spruce and Rocky Mountain are reported as discontinued operations on our Consolidated Statements of Operations as disclosed below.

Rosetta Settlement

On December 1, 2008, the U.S. Bankruptcy Court finalized the settlement with Rosetta for all of our outstanding claims related to our domestic oil and gas assets we sold to Rosetta for $1.1 billion in 2005. Under the settlement, Rosetta paid us $97 million; we completed the transfer of certain other assets; we and Rosetta extended an existing natural gas purchase agreement for an additional ten years; and we and Rosetta executed mutual releases. The original sale of our domestic oil and gas assets was recorded as discontinued operations on our 2005 Consolidated Statement of Operations. Of the $97 million settlement proceeds received, $79 million was associated with the certain other assets with a remaining net book value of approximately $42 million related to our domestic oil and gas assets we sold to Rosetta in 2005. The resulting $37 million gain is reflected as discontinued operations on our 2008 Consolidated Statement of Operations. The remaining $18 million settlement proceeds received was associated with the agreed upon fraudulent conveyance of $12 million, which is included in reorganization items on our 2008 Consolidated Statement of Operations, and approximately $6 million in revenues collected by Rosetta during the litigation period on assets retained by us.

Discontinued Operations

The table below presents the components of our discontinued operations for the periods presented (in millions):

	2010	2009	2008
Operating revenues	$ 92	$ 101	$ 100
Gain on disposal of discontinued operations	209	—	37
Income from discontinued operations before taxes	43	35	22
Less: Income tax expense	59	—	23
Discontinued operations, net of tax	$ 193	$ 35	$ 36

Other Asset Sales

On December 8, 2010, we sold a 25% undivided interest in the assets of our Freestone power plant for approximately $215 million in cash. We recorded a pre-tax gain of approximately $119 million in December 2010, which is included in gain on sale of assets on our Consolidated Statement of Operations. We continue to operate Freestone after the sale.

On March 5, 2008, we completed the sale of substantially all of the assets comprising the Fremont development project, a partially completed 550 MW natural gas-fired power plant located in Fremont, Ohio, to

First Energy Generation Corp. for approximately $254 million, plus the assumption of certain liabilities. We recorded a pre-tax gain of approximately $136 million in the first quarter of 2008, which is included in reorganization items on our 2008 Consolidated Statement of Operations.

On February 14, 2008, we completed the sale of substantially all of the assets comprising the Hillabee development project, a partially completed 774 MW combined-cycle power plant located in Alexander City, Alabama, to CER Generation, LLC for approximately $156 million, plus the assumption of certain liabilities. We recorded a pre-tax gain of approximately $63 million in the first quarter of 2008, which is included in reorganization items on our 2008 Consolidated Statement of Operations.

The sales of the Fremont and Hillabee development projects did not meet the criteria for discontinued operations due to our continuing activity in the markets in which these power plants were located; therefore, the results of operations for all periods prior to sale are included in our continuing operations and the gain on sale is included in reorganization items on our Consolidated Statements of Operations.

4. Property, Plant and Equipment, Net

As of December 31, 2010 and 2009, the components of property, plant and equipment, are stated at cost less accumulated depreciation as follows (in millions):

	2010	2009
Buildings, machinery and equipment	$ 14,578	$ 13,373
Geothermal properties	1,102	1,050
Other	273	232
	15,953	14,655
Less: Accumulated depreciation	3,690	3,322
	12,263	11,333
Land	93	74
Construction in progress	622	176
Property, plant and equipment, net	$ 12,978	$ 11,583

Total depreciation expense, including amortization of leased assets, recorded in income from operations and discontinued operations for the years ended December 31, 2010, 2009 and 2008, was $568 million, $469 million and $437 million, respectively.

We have various debt instruments that are collateralized by certain of our property, plant and equipment. See Note 6 for a detailed discussion of such instruments.

Change in Depreciation Methods, Useful Lives and Salvage Values

During 2009, we reviewed our accounting policies related to depreciation including our estimates of useful lives and salvage values. As further described below, effective October 1, 2009, we made two changes to our methods of depreciation including (i) changing from composite depreciation to component depreciation for our rotable parts utilized in our natural gas-fired power plants and (ii) changing from the units of production method to the straight line method for our Geysers Assets. In addition, we completed a life study for each of our natural gas-fired power plants and our Geysers Assets, and changed our estimate of their remaining useful lives.

Component Depreciation for Rotable Parts at our Natural Gas-Fired Power Plants — Effective October 1, 2009, we componentized our rotable parts for our natural gas-fired power plant assets for purposes of calculating depreciation. Prior to October 1, 2009, we used the composite depreciation method for all of our natural gas-fired power plant assets. Under this method, all assets comprising each power plant were combined into one group and depreciated under a composite depreciation rate. The change in the method of depreciation for rotable parts was considered a change in accounting estimate inseparable from a change in accounting principle, and resulted in changes to our depreciation expense prospectively. The change to component depreciation for our rotable parts utilized in our natural gas-fired power plants also resulted in changes to the useful lives of our rotable parts which are now generally estimated to range from 3 to 18 years. Furthermore, we reduced our estimate of salvage value for our rotable parts to 0.15% of original cost to reflect our expectation with these separable parts. Prior to this change, our composite useful lives for our natural gas-fired power plant assets, including our rotable parts, were 35 years and 40 years for our combined-cycle and our simple-cycle power plant assets, respectively. We also revised the estimated useful lives of our remaining composite pools to 37 years and 47 years for our combined-cycle and simple-cycle power plant assets, respectively, based in part on the results of our separate useful life study. Our change in useful lives is considered a change in accounting estimate and resulted in changes to our depreciation expense prospectively.

Straight Line Method for our Geysers Assets — Effective October 1, 2009, we began calculating our depreciation for our Geysers Assets under the straight line method. Prior to October 1, 2009, our Geysers Assets used the units of production method for depreciation. Our units of production depreciation rate was calculated using a depreciable base of the net book value of the Geysers Assets plus the expected future capital expenditures over the economic life of the geothermal reserves. The rate of depreciation per MWh was determined by dividing the depreciable base by total expected future generation. The change in depreciation methods was made because steam flow decline rates have become very small over the past several years as a result of our water injection program where, on average, we reinject approximately 18 million gallons of reclaimed wastewater a day back into the reservoir to replenish natural steam withdrawn for the production of power. The expectation is that the steam reservoir at our Geysers Assets will be able to supply economic quantities of steam for the foreseeable future and expected future generation is now only limited by the physical useful life of the Geysers Assets. As a result of our change from the units of production method to the straight line method for our Geysers Assets, and based in part on the results of our separate useful life study, we revised our estimates of the remaining composite useful lives of our Geysers Assets effective October 1, 2009 to 59 years and 13 years for our Geysers steam extraction and gathering assets and our Geysers power plant assets, respectively. Our change in the method of depreciation for our Geysers Assets is considered a change in accounting estimate inseparable from a change in accounting principle, and resulted in changes to depreciation expense prospectively.

The changes described above resulted in an increase in our historical depreciation expense of approximately $28 million related to our natural gas-fired power plants and a decrease in historical depreciation expense of approximately $3 million for our Geysers Assets for a net decrease to our net income attributable to Calpine of approximately $25 million or approximately $(0.05) to our basic and diluted earnings per share for the year ended December 31, 2009.

Buildings, Machinery and Equipment

This component primarily includes power plants and related equipment. Included in buildings, machinery and equipment are assets under capital leases. See Note 6 for further information regarding these assets under capital leases.

Other

This component primarily includes software and emission reduction credits that are power plant specific and not available to be sold.

Capitalized Interest

The total amount of interest capitalized was $22 million, $8 million and $20 million for the years ended December 31, 2010, 2009 and 2008, respectively.

5. Variable Interest Entities and Unconsolidated Investments

We consolidate all of our VIEs where we have determined that we are the primary beneficiary. We have the following types of VIEs consolidated in our financial statements:

Subsidiaries with Project Debt — All of our subsidiaries that have project debt have PPAs that provide financial support and are thus considered VIEs. We retain ownership and absorb the full risk of loss and potential for reward once the project debt is paid in full. Actions by the lender to assume control of collateral can occur only under limited circumstances such as upon the occurrence of an event of default, which we have determined to be unlikely. See Note 6 for further information regarding our project debt and Note 2 for information regarding our restricted cash balances.

Subsidiaries with PPAs — Certain of our majority owned subsidiaries have PPAs that limit the risk and reward of our ownership and thus constitute a VIE.

VIEs with a Purchase Option — Riverside Energy Center and OMEC have agreements that provide third parties a fixed price option to purchase power plant assets with an aggregate capacity of 1,211 MW exercisable in the years 2013 and 2019. These purchase options limit the risk and reward of our ownership and, thus, constitute a VIE.

Other VIEs — Our consolidated VIEs as of December 31, 2009, also included monetized assets secured by financing for our PCF and PCF III subsidiaries. These financings were fully repaid during the first quarter of 2010 and are no longer VIEs.

New Accounting Standards and Disclosure Requirements for VIEs

Implementation — As further discussed in Note 2, new accounting standards became effective January 1, 2010 related to accounting for and consolidation of VIEs, which required us to perform an analysis upon implementation and ongoing reassessments each reporting period of whether we are the primary beneficiary of our VIEs. The new standards generally replaced the quantitative-based risks and rewards calculation for determining which enterprise, if any, is the primary beneficiary of a VIE to a more qualitative assessment with an approach focused on identifying which enterprise has both the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or receive benefits from the VIE.

As required, we performed an analysis of all of our VIEs effective January 1, 2010 and, with the exception of OMEC, our determination of the primary beneficiary did not change. Additionally, as required each reporting period, we reviewed our VIEs and concluded no further changes to our determinations of whether we are the primary beneficiary of our VIEs were required during 2010. We concluded that we hold the obligation to absorb losses and receive benefits in all of our VIEs where we hold the majority equity interest (see discussion of 50 percent owned equity investments below). Therefore, our analysis to determine the primary beneficiary focused on determining which variable interest holder has the power to direct the most significant activities of the VIE (the primary beneficiary). Our analysis included consideration of the following primary activities which we believe to have a significant impact on a power plant's financial performance: operations and maintenance, plant dispatch, fuel strategy as well as our ability to control or influence contracting and overall plant strategy. Our approach to determining which entity holds the powers and rights was based on powers held as of the balance sheet date. Contractual terms that will apply in future periods, such as a purchase or sale option, were not considered in our analysis. Based on our analysis, we determined that we hold the power and rights to direct the most significant activities of all our majority owned VIEs.

OMEC — During the second quarter of 2007, we determined that SDG&E had a greater variability of risk compared to us based upon the prior consolidation accounting standards, which focused on which party held the greater variability in the obligation to absorb the losses or the right to receive benefits or both from the VIE. We determined that SDG&E held the greater variability as a result of a put option held by OMEC to sell the Otay Mesa Energy Center for $280 million to SDG&E, and a call option held by SDG&E to purchase the Otay Mesa Energy Center for $377 million in 2019. Accordingly, we were not the primary beneficiary, consolidation was not appropriate and we accounted for our investment in OMEC under the equity method of accounting through December 31, 2009.

The transfer of ownership in conjunction with the exercise of the put/call option, which was the driving factor in the quantitative determination of the primary beneficiary under the previous accounting standards, would not occur until 2019. Neither we, nor SDG&E, hold any powers under the combination put/call option as of January 1, 2010. Accordingly, we did not include the benefits and obligations of the put/call option in the new determination of the primary beneficiary under the current accounting standards. Based upon our analysis, we believe the significant activity that has the most impact on the financial performance of OMEC is operations and maintenance which is controlled by us. As a result, we changed our determination of the primary beneficiary from SDG&E to us effective January 1, 2010.

Prior VIE Accounting Policy — Prior to January 1, 2010, our determination of whether we were the primary beneficiary of our VIEs was made at the inception of our involvement with the VIE and only updated in response to a reconsideration event. We considered both qualitative and quantitative factors to form a conclusion as to whether we, or another interest holder, absorbed a majority of our VIEs risk of expected losses, received a majority of our VIEs potential for expected residual returns, or both. However, our determination was more quantitative in nature and also included the potential economic benefits or losses from powers and rights that we or other parties had for ownership transfer at dates in the future, primarily purchase options, but were not enforceable at the balance sheet date.

New Disclosures — Implementation of the new accounting standards also required separate disclosure on the face of our Consolidated Balance Sheets of the significant assets of a consolidated VIE that can only be used to settle obligations of the consolidated VIE and the significant liabilities of a consolidated VIE for which creditors (or beneficial interest holders) do not have recourse to the general credit of the primary beneficiary separately.

In determining which assets of our VIEs met the separate disclosure criteria, we reviewed all of our VIEs and determined this separate disclosure requirement was met where Calpine Corporation was substantially limited or prohibited from access to assets (primarily cash and cash equivalents, restricted cash and property, plant and equipment), where the VIE was not a guarantor or grantor under our primary debt facilities (our First Lien Notes and Corporate Revolving Facility) and where there were prohibitions of the VIE under agreements that prohibited guaranteeing the debt of Calpine Corporation or its other subsidiaries and where the amounts were material to our financial statements. In determining which liabilities of our VIEs met the separate disclosure criteria, we reviewed all of our VIEs and determined this separate disclosure requirement was met where our VIEs had project financing that prohibits the VIE from providing guarantees on the debt of others, where Calpine Corporation has not provided a corporate guarantee and where the amounts were material to our financial statements.

The VIEs meeting the above disclosure criteria are wholly owned subsidiaries of Calpine Corporation and include natural gas-fired power plants with an aggregate capacity of approximately 13,553 MW and 10,239 MW at December 31, 2010 and 2009, respectively. During the year ended December 31, 2010, changes to the VIEs included in this disclosure were the result of new acquisitions, construction, reconsolidations, asset sales, and repayment of project debt. For these VIEs, we may provide other operational and administrative support through various affiliate contractual arrangements between the VIEs, Calpine Corporation and its other wholly owned subsidiaries whereby we support the VIE through the reimbursement of costs and/or the purchase and sale of energy. During 2010, Calpine Corporation contributed $540 million to NDH, an indirect, wholly owned subsidiary, to fund the Conectiv Acquisition, including $110 million to complete the construction of the York Energy Center and approximately $40 million to Calpine BRSP to fund the acquisition of the Broad River and

South Point leases. Additionally, Calpine Corporation provided support to our other VIEs in the form of other cash contributions other than amounts contractually required of approximately $6 million. We are responsible for our pro rata share of construction costs related to the Russell City Energy Center until project financing has closed, and we are responsible for our pro rata share of any reimbursement obligations under a letter of credit security agreement to PG&E.

Unconsolidated VIEs and Investments

We have a 50% partnership interest in Greenfield LP and a 50% equity interest in Whitby where we do not have the power to direct the most significant activities of these entities and therefore do not consolidate them. Greenfield LP and Whitby are also VIEs. We account for these entities under the equity method of accounting and include our net equity interest in investments on our Consolidated Balance Sheets as we exercise significant influence over their operating and financial policies. During 2009 and 2008, we were not the primary beneficiary of OMEC based upon the accounting guidance in 2009 and 2008, and did not consolidate OMEC. Our equity interest in the net income (loss) from OMEC for the years ended December 31, 2009 and 2008, and both Greenfield LP and Whitby for the years ended December 31, 2010, 2009 and 2008 are recorded in (income) loss from unconsolidated investments in power plants.

At December 31, 2010 and 2009, our equity method investments included on our Consolidated Balance Sheets were comprised of the following (in millions):

	Ownership Interest as of December 31, 2010	2010	Our Maximum Exposure to Loss at December 31, 2010[2]	2009
OMEC[1]	100%	$ —	$ —	$ 144
Greenfield LP	50%	77	77	70
Whitby	50%	3	3	—
Total investments		$ 80	$ 80	$ 214

(1) OMEC was consolidated effective January 1, 2010. See Note 2.

(2) Our risk of loss related to our unconsolidated VIEs is limited to our investment balance. While we also could be responsible for our pro rata portion of debt, holders of the debt of our unconsolidated investments do not have recourse to Calpine Corporation and its other subsidiaries. The debt of our unconsolidated investments is not reflected on our Consolidated Balance Sheets. As of December 31, 2010 and 2009, our equity method investee debt was approximately $494 million and $873 million, respectively, and based on our pro rata share of each of the investments, our share of such debt would be approximately $247 million and $624 million, respectively.

The following details our (income) loss and distributions from unconsolidated investments in power plants for the years ended December 31, 2010, 2009 and 2008 (in millions):

	(Income) Loss from Unconsolidated Investments in Power Plants			Distributions		
	2010	2009	2008	2010	2009	2008
OMEC[1]	$ —	$ (32)	$ 55	$ —	$ 9	$ —
Greenfield LP	(8)	(16)	5	6	9	24
RockGen	—	—	(9)	—	—	—
Whitby	(8)	(2)	(2)	5	2	3
Auburndale	—	—	180	—	—	—
Total	$ (16)	$ (50)	$ 229	$ 11	$ 20	$ 27

(1) OMEC was consolidated effective January 1, 2010. See Note 2.

Greenfield LP — Greenfield LP is a limited partnership between certain subsidiaries of ours and a third party which operates the Greenfield Energy Centre, a 1,038 MW natural gas-fired power plant in Ontario, Canada. We and a third party each hold a 50% joint venture interest in Greenfield LP. Greenfield LP holds an 18-year term loan in the amount of CAD $648 million. Borrowings under the project finance facility bear interest at Canadian LIBOR plus 1.125% or Canadian prime rate plus 0.125%. We contributed nil, nil and $8 million for the years ended December 31, 2010, 2009 and 2008, respectively, as an additional investment in Greenfield LP.

Whitby — Represents our 50% investment in Whitby held by our Canadian subsidiaries, which were reconsolidated on the Canadian Effective Date.

RockGen — On December 6, 2007, our subsidiary RockGen, which had leased the RockGen Energy Center from the RockGen Owner Lessors pursuant to a sale and leaseback arrangement, entered into a settlement agreement and a purchase and sale agreement with the RockGen Owner Lessors to purchase the RockGen Energy Center for an allowed general unsecured claim of approximately $145 million. While the allowed claim was approved by the U.S. Bankruptcy Court in December 2007, the purchase agreement was conditional upon certain events before title could transfer to us. All of the conditions were satisfied in January 2008 and the acquisition of RockGen Energy Center assets closed on January 15, 2008.

The purchase of the RockGen Energy Center assets, which terminated the prior sale-leaseback agreement, also required us to reconsider if we were RockGen's primary beneficiary. RockGen's PPA with WP&L contained a call option which allowed WP&L and related parties to purchase the RockGen Energy Center assets at a fixed price on May 31, 2009, provided they gave us 180-days prior written notice. The call option effectively created a ceiling value for us and absorbed the majority of the expected change in fair value of the RockGen Energy Center assets and transferred it to WP&L. As a result, we determined that we were not RockGen's primary beneficiary. Accordingly, we deconsolidated RockGen during the first quarter of 2008, and accounted for our investment in RockGen under the equity method through December 2, 2008.

On December 2, 2008, (180 days prior to May 31, 2009) WP&L's period to exercise the purchase option expired without providing written notification. This resulted in a reconsideration event and we determined that expiration of the option eliminated the transfer of the risk of loss and potential for future reward to us and that we are RockGen's primary beneficiary. We reconsolidated RockGen as of December 2, 2008. The expiration of the purchase option also terminated WP&L's variable interest and RockGen is no longer a VIE.

Auburndale — Auburndale was an unconsolidated subsidiary accounted for under the equity method of accounting for the period from August 21, 2008 through the date of its sale on November 21, 2008. Prior to August 21, 2008, we consolidated Auburndale as we determined that we were Auburndale's primary beneficiary. Pomifer, an unrelated party, held a preferred interest which entitled it to approximately 70% of Auburndale's cash distributions through 2013. Pomifer also held an option which, upon exercise, entitled Pomifer to an additional 20% of Auburndale's cash distributions through 2013, as well as certain drag-along rights that would require us to sell our remaining interest in Auburndale should Pomifer sell its interest in Auburndale. On August 21, 2008, Pomifer exercised its option to the additional 20% of cash distributions, which required us, under U.S. GAAP, to reconsider whether we remained Auburndale's primary beneficiary. We determined that we were no longer Auburndale's primary beneficiary and we deconsolidated Auburndale during the third quarter of 2008. On September 30, 2008, Pomifer notified us of their intent to exercise their drag-along rights. Accordingly, we determined that a sale of our remaining interest was probable. We compared our expected proceeds from such sale to the net book value of our interest in Auburndale at September 30, 2008, to determine if an impairment existed and recorded an impairment loss of approximately $180 million, which is included in our (income) loss from unconsolidated investments in power plants on our Consolidated Statement of Operations during the year ended December 31, 2008. We sold our remaining interest in Auburndale on November 21, 2008.

Inland Empire Energy Center Put and Call Options — We hold a call option to purchase the Inland Empire Energy Center (a 775 MW natural gas-fired power plant located in California, which began commercial operations on May 3, 2010) from GE that may be exercised between years 7 and 14 after the start of commercial operation. GE holds a put option whereby they can require us to purchase the power plant, if certain plant performance criteria are met during year 15 after the start of commercial operation. We determined that we were not the primary beneficiary of the Inland Empire power plant, and we do not consolidate it due to the fact that GE directs the most significant activities of the power plant including operations and maintenance.

Significant Subsidiary — OMEC met the criteria of a significant subsidiary as defined under SEC guidelines based upon the relationship of our equity income from our investment in this subsidiary to our consolidated net income before income taxes for the years ended December 31, 2009 and 2008. OMEC was consolidated effective January 1, 2010. Condensed combined financial statements for our unconsolidated subsidiaries for the periods in which OMEC was a significant subsidiary and was accounted for under the equity method of accounting are presented below (in millions):

Condensed Combined Balance Sheet
of Our Unconsolidated Subsidiaries
December 31, 2009

	2009
Assets:	
Cash and cash equivalents	$ 33
Current assets(1)	70
Property, plant and equipment, net	1,220
Other assets	54
Total assets	$ 1,377
Liabilities:	
Current maturities of long-term debt	$ 37
Current liabilities(1)	54
Long-term debt	836
Long-term derivative liabilities	95
Other liabilities	47
Total liabilities	1,069
Member's interest	308
Total liabilities and member's interest	$ 1,377

(1) Approximately $63 million has been netted between current assets and current liabilities in the table above as we determined there was a legal right of offset. These amounts were presented gross in our 2009 Form 10-K.

Condensed Combined Statements of Operations
of Our Unconsolidated Subsidiaries
For the Years Ended December 31, 2009 and 2008

	2009	2008(1)
Revenues	$ 256	$ 121
Operating expenses	195	106
Impairment of equity method investment	—	180
Income (loss) from operations	61	(165)
Interest (income) expense	2	12
Other (income) expense, net	5	58
Net income (loss)	$ 54	$ (235)

(1) Amounts include results from Auburndale and RockGen during the periods they were deconsolidated in 2008.

6. Debt

Our debt at December 31, 2010 and 2009, was as follows (in millions):

	2010	2009
First Lien Notes	$ 4,691	$ 1,200
Project financing, notes payable and other	1,922	2,289
NDH Project Debt	1,258	—
First Lien Credit Facility(1)	1,184	4,661
CCFC Notes	965	959
Capital lease obligations	236	250
Commodity Collateral Revolver	—	100
Total debt	10,256	9,459
Less: Current maturities	152	463
Debt, net of current portion	$ 10,104	$ 8,996

(1) The amount outstanding as of December 31, 2010 was repaid on January 14, 2011 with proceeds received from the issuance of the 2023 First Lien Notes.

Annual Debt Maturities

Contractual annual principal repayments or maturities of debt instruments as of December 31, 2010, are as follows (in millions):

2011	$ 152
2012	204
2013	121
2014	1,527
2015	314
Thereafter	8,008
Total debt	10,326
Less: Discount	70
Total	$ 10,256

Issuance of First Lien Notes and Amendment of First Lien Credit Facility

We executed the First Amendment to Credit Agreement and Second Amendment to Collateral Agency and Intercreditor Agreement dated as of August 20, 2009, which amended both the First Lien Credit Facility Credit Agreement and the First Lien Credit Facility Collateral Agency and Intercreditor Agreement. The amendment provided us the option, subject to certain conditions, to buy back debt at a discount using cash on hand via an auction process; to offer first lien bonds in exchange for or to retire First Lien Credit Facility term loans; to issue up to $2.0 billion of first lien bonds in lieu of issuing first lien term loans under the accordion provision of our First Lien Credit Facility; and to extend all or a portion of the revolver and term loan maturities, on revised terms, subject to acceptance by applicable lenders.

During 2010 and 2009, we issued four tranches of First Lien Notes, and a final tranche on January 14, 2011, each in private placement transactions. We received no net cash proceeds from the issuance of the 2017 First Lien Notes, as the offer and sale of these First Lien Notes was consummated as a permitted debt exchange pursuant to our First Lien Credit Facility. We received cash proceeds from the issuances of the 2019, 2020, 2021, and 2023 First Lien Notes, which were used to repay our First Lien Credit Facility term loans, and pay fees and expenses in connection with the offerings and such repayment thereby terminating the First Lien Credit Facility in January 2011, in accordance with its terms. Each issuance of the First Lien Notes was made under an amended and restated indenture or an indenture (collectively, "the related indentures") among Calpine, the guarantors who are a party thereto and Wilmington Trust Company, as trustee each dated the same date as the related issuance. We may also redeem all or a portion of the First Lien Notes at a premium as defined in the related indentures. Our First Lien Notes are summarized in the table below (in millions, except for interest rates):

	Outstanding at December 31,		Weighted Average Effective Interest Rates	
	2010	2009	2010	2009
2017 First Lien Notes[1]	$ 1,200	$ 1,200	7.5%	7.5%
2019 First Lien Notes[2]	400	—	8.2	—
2020 First Lien Notes[3]	1,091	—	8.1	—
2021 First Lien Notes[4]	2,000	—	7.7	—
Total First Lien Notes	$ 4,691	$ 1,200		

(1) On October 21, 2009, we issued $1.2 billion in aggregate principal amount of 7.25% senior secured notes maturing on October 15, 2017. The 2017 First Lien Notes bear interest at 7.25% per annum payable semi-annually on April 15 and October 15 of each year, beginning on April 15, 2010.

(2) On May 25, 2010, we issued $400 million in aggregate principal amount of 8.0% senior secured notes maturing on August 15, 2019. The 2019 First Lien Notes bear interest at 8.0% per annum payable semi-annually on February 15 and August 15 of each year, beginning on August 15, 2010.

(3) On July 23, 2010, we issued $1.1 billion in aggregate principal amount of 7.875% senior secured notes maturing on July 31, 2020. The 2020 First Lien Notes bear interest at 7.875% per annum payable semi-annually on January 31 and July 31 of each year, beginning on January 31, 2011.

(4) On October 22, 2010, we issued $2.0 billion in aggregate principal amount of 7.50% senior secured notes maturing on February 15, 2021. The 2021 First Lien Notes bear interest at 7.50% per annum payable semi-annually on February 15 and August 15 of each year, beginning on February 15, 2011.

Issuance of 2023 First Lien Notes — On January 14, 2011, we issued $1.2 billion in aggregate principal amount of 7.875% senior secured notes due 2023 in a private placement. The 2023 First Lien Notes bear interest at 7.875% payable semi-annually on January 15 and July 15 of each year, beginning on July 15, 2011. The 2023 First Lien Notes will mature on January 15, 2023.

We had deferred financing costs of approximately $216 million recorded on our Consolidated Balance Sheet at December 31, 2010, and we recorded approximately $61 million and approximately $25 million in debt extinguishment costs for the years ended December 31, 2010 and 2009, respectively, from the write-off of unamortized deferred financing costs related to the issuances of the First Lien Notes and the repayment of the First Lien Credit Facility term loans. We expect to record additional deferred financing costs of approximately $22 million on our Consolidated Balance Sheet and approximately $19 million in debt extinguishment costs during the first quarter of 2011 related to the issuance of the 2023 First Lien Notes.

Our First Lien Notes are secured equally and ratably with indebtedness incurred under our Corporate Revolving Facility and certain other indebtedness that is permitted to be secured by such assets by a first-priority lien, subject to certain exceptions and permitted liens, on substantially all of our and certain of the guarantors' existing and future assets. Additionally, our First Lien Notes rank equally in right of payment with all of our and the guarantors' other existing and future senior indebtedness, and will be effectively subordinated in right of payment to all existing and future liabilities of our subsidiaries that do not guarantee our First Lien Notes.

Subject to certain qualifications and exceptions, our First Lien Notes will, among other things, limit our ability and the ability of the guarantors to:

- incur or guarantee additional first lien indebtedness;
- enter into certain types of commodity hedge agreements that can be secured by first lien collateral;
- enter into sale and leaseback transactions;
- create or incur liens; and
- consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries on a combined basis.

Corporate Revolving Facility

We executed the Third Amendment to the First Lien Credit Facility credit agreement on December 10, 2010. This amendment provided us the ability to replace the First Lien Credit Facility revolver with the Corporate Revolving Facility. On December 10, 2010, we executed our $1.0 billion Corporate Revolving Facility, which replaced our $1.0 billion revolver under our First Lien Credit Facility and allows for up to $750 million of availability for the issuance of letters of credit and up to $50 million as a swingline subfacility. The Corporate Revolving Facility can be used for our (and to the extent permitted therein, our subsidiaries') working capital requirements and other general corporate purposes. We may increase or we may add one or more incremental revolving credit facilities, on one or more occasions, up to an additional $250 million in the aggregate under certain circumstances.

Borrowings under the Corporate Revolving Facility bear interest, at our option, at either a base rate or LIBOR rate (with the exception of any swingline borrowings, which bear interest at the base rate). Base rate borrowings shall be at the base rate, plus an applicable margin ranging from 2.00% to 2.25% as provided in the Credit Agreement. Base rate is defined as the higher of (i) the Federal Funds Effective Rate, as published by the Federal Reserve Bank of New York, plus 0.50% and (ii) the rate the administrative agent announces from time to time as its prime per annum rate. LIBOR rate borrowings shall be at the British Bankers' Association Interest Settlement Rates for the interest period as selected by us as a one, two, three, six or, if agreed by all relevant lenders, nine or twelve month interest period, plus an applicable margin ranging from 3.00% to 3.25%. Interest payments are due on the last business day of each calendar quarter for base rate loans and the earlier of (i) the last day of the interest period selected or (ii) each day that is three months (or a whole multiple thereof) after the first day for the interest period selected for LIBOR rate loans. Letter of credit fees for issuances of letters of credit include fronting fees equal to that percentage per annum as may be separately agreed upon between us and the issuing lenders and a participation fee for the lenders equal to the applicable interest margin for LIBOR rate borrowings. Drawings under letters of credit shall be repaid within 2 business days or be converted into borrowings as provided in the Credit Agreement. We will incur an unused commitment fee ranging from 0.50% to 0.75% on the unused amount of commitments under the Corporate Revolving Facility.

The Corporate Revolving Facility does not contain any requirements for mandatory prepayments, except in the case of certain designated asset sales in excess of $3.0 billion in the aggregate. However, we may voluntarily repay, in whole or in part, the Corporate Revolving Facility, together with any accrued but unpaid interest, with prior notice and without premium or penalty. Amounts repaid may be reborrowed and we may also voluntarily reduce the commitments under the Corporate Revolving Facility without premium or penalty. The Corporate Revolving Facility matures December 10, 2015.

The Corporate Revolving Facility is guaranteed and secured by each of our current domestic subsidiaries that was a guarantor under the First Lien Credit Facility and will also be additionally guaranteed by our future domestic subsidiaries that are required to provide such a guarantee in accordance with the terms of the Corporate

Revolving Facility. The Corporate Revolving Facility ranks equally in right of payment with all of our and the guarantors' other existing and future senior indebtedness, and will be effectively subordinated in right of payment to all existing and future liabilities of our subsidiaries that do not guarantee the Corporate Revolving Facility. The Corporate Revolving Facility also requires compliance with financial covenants that include a minimum cash interest coverage ratio and a maximum net leverage ratio.

Repayment and Termination of the First Lien Credit Facility

Following our emergence from Chapter 11, our First Lien Credit Facility served as our primary debt facility. The First Lien Credit Facility included an original $6.0 billion of senior secured term loans, a $1.0 billion senior secured revolving facility and, subject to market conditions, the ability to raise up to $2.0 billion of incremental term loans under an "accordion" provision available on a senior secured basis in order to refinance secured debt of our subsidiaries. As of December 31, 2010, under our First Lien Credit Facility, we had approximately $1.2 billion outstanding under the term loans. Borrowings of term loans under our First Lien Credit Facility incurred interest at a floating rate, at our option, of LIBOR plus 2.875% per annum or base rate plus 1.875% per annum with quarterly payments of principal equal to 0.25% of the original principal amount of First Lien Credit Facility term loans subject to adjustments as a result of the First Lien Note offerings and repayments from excess cash flows. The First Lien Credit Facility maturity's scheduled date was March 29, 2014. We repaid or exchanged our First Lien Credit Facility term loans through proceeds received from the issuances of the First Lien Notes, together with operating cash, in the following amounts:

- In October 2009, we exchanged approximately $1.2 billion with the issuance of the 2017 First Lien Notes.
- In May 2010, we repaid approximately $394 million from the issuance of the 2019 First Lien Notes.
- In July 2010, we repaid approximately $1.1 billion from the issuance of the 2020 First Lien Notes.
- In October 2010, we repaid approximately $2.0 billion from the issuance of the 2021 First Lien Notes.
- In January 2011, we repaid the remaining approximately $1.2 billion from the issuance of the 2023 First Lien Notes, together with operating cash, thereby terminating the First Lien Credit Facility in accordance with its terms.

Project Financing, Notes Payable and Other

The components of our project financing are (in millions, except for interest rates):

	Outstanding at December 31,		Weighted Average Effective Interest Rates[1]	
	2010	2009	2010	2009
Steamboat due 2017	$ 445	$ 452	6.6%	6.9%
OMEC[2]	364	—	6.8	—
Calpine BRSP[3]	297	—	5.7	—
Metcalf due 2015	251	261	6.9	7.0
Pasadena[4]	208	228	8.6	8.6
Bethpage Energy Center 3, LLC due 2020-2025[5]	103	107	7.0	7.0
Deer Park due 2012	99	128	7.7	7.5
Gilroy note payable due 2014	64	77	10.6	10.6
Gilroy Energy Center, LLC due 2011	38	76	7.3	7.3
Whitby Holdings due 2017	26	31	9.1	8.9
GEC Holdings, LLC preferred interest due 2011	14	25	16.6	13.9
Riverside Energy Center, LLC due 2011[6]	—	311	—	7.6
Broad River[4]	—	210	—	8.1
Rocky Mountain Energy Center, LLC due 2011[6]	—	140	—	7.7
PCF III due 2010[7]	—	84	—	11.3
Blue Spruce due 2017[6]	—	76	—	4.9
PCF due 2010[7]	—	55	—	9.6
Other	13	28	—	—
Total	$1,922	$2,289		

(1) Our weighted average interest rate calculation includes the amortization of deferred financing costs and debt discount.

(2) OMEC was an unconsolidated subsidiary and therefore, the debt was not included on our Consolidated Balance Sheet as of December 31, 2009. See Note 2.

(3) See further discussion of our Calpine BRSP debt below.

(4) Represent sale-leaseback transactions that are accounted for as financing transactions under U.S. GAAP. Broad River was eliminated with the assumption of the Calpine BRSP debt discussed below.

(5) Represents a weighted average of first and second lien loans.

(6) Amounts were repaid on December 6, 2010 with the proceeds received from the sale of Blue Spruce and Rocky Mountain. See Note 3 for our sale of Blue Spruce and Rocky Mountain.

(7) Amounts were repaid from cash on hand on February 1, 2010 and February 5, 2010, for PCF and PCF III, respectively.

Our project financings are collateralized solely by the capital stock or partnership interests, physical assets, contracts and/or cash flows attributable to the entities that own the power plants. The lenders recourse under these project financings is limited to such collateral.

OMEC — As further discussed in Note 2, we added approximately $375 million in project debt to our Consolidated Balance Sheet when we consolidated OMEC effective January 1, 2010. OMEC has a $377 million non-recourse project term loan, which matures in April 2019. The term loan bears interest at LIBOR plus 1.25%.

Calpine BRSP — As further discussed in Note 3, we assumed debt with a fair value of approximately \$297 million upon closing the purchase of our Broad River and South Point power plant leases in December 2010. Prior to our acquisition, we operated the Broad River power plant under a sale-leaseback transaction that was accounted for as a financing transaction under U.S. GAAP, and included in the table above as of December 31, 2009. We operated the South Point power plant under an operating lease; both leases were with CIT Capital USA Inc. The purchase of the power plants added an incremental \$85 million in consolidated debt as the transaction eliminated approximately \$212 million in debt and accrued interest owed to CIT Capital USA Inc. by our Broad River power plant. We allocated the value of the consideration paid in the transaction based upon the relative fair value of both plants, and the result was an allocation of assumed debt that was greater than the prior debt obligation resulting in a pre-tax loss of approximately \$30 million, which is recorded as debt extinguishment costs by our Broad River power plant and included in debt extinguishment costs on our Consolidated Statement of Operations. The Calpine BRSP debt has a senior term loan facility, which bears interest at LIBOR (subject to a minimum of 3.0%), plus the applicable margin of 4.5%. Approximately \$1 million of principal amount is payable semi-annually with the remaining balance payable in 2014. The Calpine BRSP senior term loan facility matures on June 4, 2014.

Steamboat — On November 24, 2009, Steamboat amended and extended the terms of its credit agreement. The Steamboat Amended Credit Facility increases the amount of term loans outstanding by \$17 million from \$448 million to \$465 million. The increase in the borrowing was used to pay accrued and unpaid interest, breakage costs and other fees in connection with closing the Steamboat Amended Credit Facility. The Steamboat Amended Credit Facility also provides for a "security fund" letter of credit facility of up to \$11 million and a "DSR" letter of credit facility of up to approximately \$23 million. The maturity date of the term loans facilities has been extended from December 2011 to November 24, 2017. The security fund letter of credit facility matures on November 24, 2017 with the term loans, and the DSR letter of credit facility matures on September 29, 2017. We recorded approximately \$7 million in new deferred financing costs on our Consolidated Balance Sheet as of December 31, 2009, and approximately \$2 million in debt extinguishment costs related to the write-off of the old deferred financing costs on our Consolidated Statement of Operations for the year ended December 31, 2009.

Interest on the term loans is at a base rate or LIBOR (as defined in the Steamboat Amended Credit Facility) as elected by Steamboat plus a rate margin which escalates from 2.875% to 3.375% (less 1% for a base rate loan) during the term of the Steamboat Amended Credit Facility. Principal and interest are due and payable on the last banking day of each calendar quarter. Steamboat may, at its option convert the interest rate on all or a portion of the amounts outstanding under the term loans to the one month, three month or six month LIBOR rate plus the rate margin and may convert any LIBOR rate loan back to a base rate loan. Both the security fund and "DSR" letter of credit facilities incur a commitment fee equal to 1.0% for the average unutilized letters of credit and a letter of credit participation fee equal to the rate margin for the stated amount of the issued letters of credit. Under the Steamboat Amended Credit Facility we are required to hedge a minimum of 75% of our interest rate exposure, and as of December 31, 2010, we have hedged approximately 95% of this interest rate exposure with interest rate swaps. See Note 8 for further discussion regarding our interest rate swaps.

Subject to certain limitations and minimum amounts, Steamboat may elect to permanently reduce the commitment amounts under both the security fund and DSR letter of credit facilities and prepay, without penalty, in whole or in part, the amounts outstanding under the term loans. The Steamboat Amended Credit Facility contains certain restrictive covenants and allows for acceleration of the debt in the event of certain defaults and is secured, subject to certain exceptions and permitted liens, by all real and personal property of Steamboat and its wholly owned subsidiaries, Freeport Energy Center and Mankato Power Plant.

Deer Park — On January 21, 2009, Deer Park, our indirect wholly owned subsidiary, closed on \$156 million of senior secured credit facilities, which include a \$150 million term facility and a \$6 million letter of credit facility. Proceeds received were used to settle an existing commodity contract of approximately \$79 million, pay financing and legal fees of approximately \$8 million and fund approximately \$22 million in restricted cash. The remainder was distributed to Calpine Corporation for general corporate purposes. The senior term loan facility matures on January 21, 2012, and bears interest of LIBOR plus 3.5% or base rate plus 2.5% at Deer Park's option.

NDH Project Debt

On June 8, 2010, NDH entered into a credit agreement, and we received net proceeds of $1.3 billion on July 1, 2010, which were used, together with available cash, to pay the Conectiv Acquisition purchase price of approximately $1.64 billion and also fund a cash contribution from Calpine Corporation to NDH of $110 million to complete construction of the York Energy Center. Our NDH Project Debt includes a $1.3 billion seven-year senior secured term facility and a $100 million three-year senior secured revolving credit facility, of which up to $50 million will be available through a subfacility in the form of letters of credit. On July 1, 2010, the term facility was funded in the amount of $1.3 billion. The NDH Project Debt was issued with an original issue discount of $28 million, and we recorded deferred financing costs of approximately $40 million on our Consolidated Balance Sheet. Our NDH Project Debt bears interest at a floating rate, at our option, at a rate per annum equal to the alternate base rate or the adjusted LIBOR (subject to a minimum of 1.5%), plus, in each case, the applicable margin, which varies for the revolving credit facility (as defined in our NDH Project Debt agreement). An amount equal to 0.25% of the aggregate principal amount of the senior secured term facility outstanding on July 1, 2010, which was $1.3 billion, will be payable at the end of each quarter commencing with the first full quarter after July 1, 2010, with the remaining balance payable on July 1, 2017. Additional repayments of principal will be required from excess cash flows (as defined in our NDH Project Debt agreement). No periodic principal payments are required with respect to the revolving credit facility. The NDH Project Debt also required that we enter into interest rate swap agreements to fix the variable LIBOR portion of our interest rate for a minimum of 50% of our debt. We executed three interest rate swap transactions in August 2010 with an initial aggregate notional amount of $715 million at a fixed LIBOR rate of 1.8275%.

NDH's obligations under the NDH Project Debt are unconditionally guaranteed by each existing and subsequently acquired or organized domestic, wholly owned subsidiary of NDH (including the entities acquired) and is secured by a first- priority lien on substantially all of NDH's and the guarantors' existing and future assets, in each case subject to certain exceptions and permitted liens. NDH and its subsidiaries (subject to certain exceptions) have made certain representations and warranties and are required to comply with various affirmative and negative covenants including, among others, certain limitations and prohibitions relating to additional indebtedness, liens, restricted payments, mergers and asset sales and certain financial covenants relating to limitations on capital expenditures, minimum interest coverage and maximum leverage. The NDH Project Debt is subject to customary events of default included in financing transactions, including, among others, failure to make payments when due, certain defaults under other material indebtedness, breach of certain covenants, breach of certain representations and warranties, involuntary or voluntary bankruptcy, and material judgments. Neither Calpine Corporation nor any of its subsidiaries, other than NDH and its subsidiaries (subject to certain exceptions), are guarantors under the NDH Project Debt.

As part of the Conectiv Acquisition and NDH Project Debt, we entered into various intercompany agreements with our NDH subsidiaries for the related sales and purchases of power, natural gas and the operation and maintenance of our NDH power plants, which will not materially impact our results of operations, financial condition or cash flows on a consolidated basis. While there is no direct recourse by holders of the NDH Project Debt to Calpine Corporation, a substantial portion of the commodity price risk related to NDH's power generation is absorbed by Calpine Energy Services, L.P., an indirect, wholly owned subsidiary of Calpine Corporation, which purchases the power generated by NDH under an intercompany tolling agreement, which is guaranteed by Calpine Corporation.

The weighted average interest rates, which includes the amortization of deferred financing costs and debt discount, for our NDH Project Debt for 2010 was 7.9%.

CCFC Notes, CCFC Old Notes and CCFC Term Loans

On May 19, 2009, our wholly owned subsidiaries, CCFC and CCFC Finance, issued approximately $1.0 billion aggregate principal amount of CCFC Notes in a private placement. Interest on the CCFC Notes accrues at the rate of 8.0% per annum and is payable semi-annually in arrears on each June 1 and December 1, commencing on December 1, 2009. The CCFC Notes, which mature on June 1, 2016, are guaranteed by two of CCFC's subsidiaries. The CCFC Notes and the related guarantees are secured, subject to certain exceptions and permitted liens, by all real and personal property of CCFC and CCFC's material subsidiaries (including the CCFC Guarantors), consisting primarily of six natural gas power plants as well as the equity interests in CCFC and the CCFC Guarantors. The CCFC Notes are not guaranteed by Calpine Corporation and are without recourse to Calpine Corporation or any of our other non-CCFC or CCFC Finance subsidiaries or assets. The net proceeds received of $939 million, together with CCFC cash on hand of $271 million, were used to:

- repay the $364 million outstanding under the CCFC Term Loans on May 19, 2009;
- redeem the $415 million outstanding principal amount of CCFC Old Notes on June 18, 2009;
- distribute $327 million to CCFC's indirect parent, CCFCP, which was used by CCFCP to redeem its $300 million CCFCP Preferred Shares discussed below on or before July 1, 2009; and
- in each case, pay any interest, prepayment penalties and other amounts due through the date of such repayment or redemption.

In connection with the CCFC Refinancing, we recorded $49 million in debt extinguishment costs for the year ended December 31, 2009. Debt extinguishment costs are comprised of $7 million from the write-off of unamortized deferred financing costs and unamortized debt discount, $24 million of prepayment penalties related to redemption of the CCFC Old Notes, $2 million from the write-off of unamortized deferred financing costs and unamortized debt discount and $16 million related to prepayment penalties related to the redemption of the CCFCP Preferred Shares.

We also recorded approximately $21 million in new deferred financing costs on our Consolidated Balance Sheet upon closing the CCFC refinancing.

The weighted average interest rates, which includes the amortization of deferred financing costs and debt discount, for our CCFC Notes for 2010 and 2009 was 8.9%.

Capital Lease Obligations

The following is a schedule by year of future minimum lease payments under capital leases and failed sale-leaseback transactions together with the present value of the net minimum lease payments as of December 31, 2010 (in millions):

	Sale-Leaseback Transactions[1]	Capital Lease	Total
2011	$ 43	$ 38	$ 81
2012	41	40	81
2013	38	38	76
2014	25	40	65
2015	25	36	61
Thereafter	169	239	408
Total minimum lease payments	341	431	772
Less: Amount representing interest	127	195	322
Present value of net minimum lease payments	$ 214	$ 236	$ 450

(1) Amounts are accounted for as financing transactions under U.S. GAAP and are included in our project financing, notes payable and other amounts above.

The primary types of property leased by us 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 remaining lease terms range up to 39 years (including lease renewal options). Some of the lease agreements contain customary restrictions on dividends up to Calpine Corporation, additional debt and further encumbrances similar to those typically found in project financing agreements. As of December 31, 2010 and 2009, the asset balances for the leased assets totaled approximately $1.0 billion and $1.3 billion with accumulated amortization of $312 million and $349 million, respectively. See Note 15 for a discussion of capital leases guaranteed by Calpine Corporation.

Other Financing Agreements

During the first quarter of 2008, we entered into a letter of credit facility related to our subsidiary Calpine Development Holdings, Inc. under which up to $150 million is available for letters of credit. On December 11, 2009, we amended the letter of credit facility to extend the maturity from January 31, 2010 to December 11, 2012, with an option to increase the letters of credit available from $150 million to $200 million by satisfying certain conditions. On June 30, 2010, we increased the availability under the letters of credit by $50 million to $200 million. As of December 31, 2010 and 2009, $165 million and $116 million in letters of credit, respectively, had been issued under this facility.

On July 8, 2008, we entered into the Commodity Collateral Revolver, a two-year, $300 million secured revolving credit facility, which shared the benefits of the collateral subject to the liens under our First Lien Credit Facility ratably with the lenders under our First Lien Credit Facility. At closing, we borrowed an initial advance of $100 million. Amounts borrowed under the Commodity Collateral Revolver were used to collateralize obligations to counterparties under eligible commodity hedge agreements. On August 13, 2009, we terminated $200 million of the remaining availability under the Commodity Collateral Revolver in accordance with its terms as energy commodity prices were not expected to exceed stated thresholds in the near future and it was considered unlikely that any of the $200 million remaining availability would be available to us. The Commodity Collateral Revolver was repaid on July 8, 2010.

Letters of Credit Facilities

The table below represents amounts issued under our letter of credit facilities as of December 31, 2010 and 2009 (in millions):

	2010	2009
Corporate Revolving Facility[1]	$ 443	$ —
First Lien Credit Facility[1]	—	206
Calpine Development Holdings, Inc.	165	116
NDH Credit Facility	34	—
Various project financing facilities	69	90
Total	$ 711	$ 412

(1) When we entered into our Corporate Revolving Facility on December 10, 2010, the letters of credit issued under our First Lien Credit Facility were either replaced by letters of credit issued by the Corporate Revolving Facility or back-stopped by an irrevocable standby letter of credit issued by Deutsche Bank AG New York Branch. Our letters of credit under our Corporate Revolving Facility as of December 31, 2010 includes those that were back-stopped of approximately $83 million; however, we expect that the back-stopped letters of credit will be returned and extinguished in early 2011.

Fair Value of Debt

We record our debt instruments based on contractual terms, net of any applicable premium or discount. We did not elect to apply the alternative U.S. GAAP provisions of the fair value option for recording financial assets and financial liabilities at fair value on our Consolidated Financial Statements. We measured the fair value of our debt instruments as of December 31, 2010, using market information including credit default swap rates and historical default information, quoted market prices or dealer quotes for the identical liability when traded as an asset and discounted cash flow analyses based on our current borrowing rates for similar types of borrowing arrangements. The following table details the fair values and carrying values of our debt instruments as of December 31, 2010 and 2009 (in millions):

	2010		2009	
	Fair Value	Carrying Value	Fair Value	Carrying Value
First Lien Notes	$ 4,695	$ 4,691	$ 1,138	$ 1,200
First Lien Credit Facility	1,182	1,184	4,402	4,661
Project financing, notes payable and other[1]	1,673	1,708	1,808	1,840
NDH Project Debt	1,303	1,258	—	—
CCFC Notes	1,067	965	1,030	959
Commodity Collateral Revolver	—	—	94	100
Total	$ 9,920	$ 9,806	$ 8,472	$ 8,760

(1) Excludes lease obligation related to sale-leaseback transactions that are accounted for as financing transactions under U.S. GAAP.

7. Fair Value Measurements

U.S. GAAP establishes a fair value hierarchy which classifies fair value measurements from level 1 through level 3 based upon the inputs used to measure fair value:

Level 1 — Quoted prices (unadjusted) are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 — Pricing inputs include quoted prices for similar assets and liabilities in active markets, and inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

Level 3 — Pricing inputs include significant inputs that are generally less observable or from unobservable sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Our Assets and Liabilities with Recurring Fair Value Measurements

Cash Equivalents — Highly liquid investments which meet the definition of cash equivalents, primarily investments in money market accounts, are included in both our cash and cash equivalents and in restricted cash on our Consolidated Balance Sheets. Certain of our money market accounts invest in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. Government, its agencies or instrumentalities. Our cash equivalents are classified within level 1 of the fair value hierarchy.

Margin Deposits and Margin Deposits Held by Us Posted by Our Counterparties — Margin deposits and margin deposits held by us posted by our counterparties represent cash collateral paid between our counterparties and us to support our commodity contracts. Our margin deposits and margin deposits held by us posted by our counterparties are generally cash and cash equivalents and are classified within level 1 of the fair value hierarchy.

Derivatives — The primary factors affecting the fair value of our derivative instruments at any point in time are the volume of open derivative positions (MMBtu, MWh and $ notional amounts); market price levels, primarily for power and natural gas; our credit standing and that of our counterparties for our energy commodity derivatives; and prevailing interest rates for our interest rate swaps. Prices for power and natural gas and interest rates are volatile, which can result in material changes in the fair value measurements reported in our financial statements in the future.

We utilize market data, such as pricing services and broker quotes, and assumptions that we believe market participants would use in pricing our assets or liabilities including assumptions about risks and the risks inherent to the inputs in the valuation technique. These inputs can be either readily observable, market corroborated or generally unobservable. The market data obtained from broker pricing services is evaluated to determine the nature of the quotes obtained and, where accepted as a reliable quote, used to validate our assessment of fair value; however, other qualitative assessments are used to determine the level of activity in any given market. We primarily apply the market approach and income approach for recurring fair value measurements and utilize what we believe to be the best available information. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observability of those inputs.

The fair value of our derivatives includes consideration of our credit standing, the credit standing of our counterparties and the impact of credit enhancements, if any. We have also recorded credit reserves in the determination of fair value based on our expectation of how market participants would determine fair value. Such valuation adjustments are generally based on market evidence, if available, or our best estimate.

Our level 1 fair value derivative instruments primarily consist of natural gas swaps, futures and options traded on the NYMEX.

Our level 2 fair value derivative instruments primarily consist of interest rate swaps and OTC power and natural gas forwards for which market-based pricing inputs are observable. Generally, we obtain our level 2 pricing inputs from markets such as the Intercontinental Exchange and Bloomberg. To the extent we obtain prices from brokers in the marketplace, we have procedures in place to ensure that prices represent executable prices for market participants. In certain instances, our level 2 derivative instruments may utilize models to measure fair value. These models are primarily industry-standard models that incorporate various assumptions, including quoted interest rates, correlation, volatility, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Our level 3 fair value derivative instruments primarily consist of our OTC power and natural gas forwards and options where pricing inputs are unobservable, as well as other complex and structured transactions. Complex or structured transactions are tailored to our or our customers' needs and can introduce the need for internally-developed model inputs which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in level 3. Our valuation models may incorporate historical correlation information and extrapolate available broker and other information to future periods. In cases where there is no corroborating market information available to support significant model inputs, we initially use the transaction price as the best estimate of fair value. OTC options are valued using industry-standard models, including the Black-Scholes pricing model. At each balance sheet date, we perform an analysis of all instruments subject to fair value measurement and include in level 3 all of those whose fair value is based on significant unobservable inputs.

The following tables present our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010 and 2009, by level within the fair value hierarchy. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Assets and Liabilities with Recurring Fair Value Measures as of December 31, 2010			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Cash equivalents[1]	$ 1,297	$ —	$ —	$ 1,297
Margin deposits	162	—	—	162
Commodity instruments:				
Commodity futures contracts	550	—	—	550
Commodity forward contracts[2]	—	287	54	341
Interest rate swaps	—	4	—	4
Total assets	$ 2,009	$ 291	$ 54	$ 2,354
Liabilities:				
Margin deposits held by us posted by our counterparties	$ 6	$ —	$ —	$ 6
Commodity instruments:				
Commodity futures contracts	574	—	—	574
Commodity forward contracts[2]	—	119	24	143
Interest rate swaps	—	371	—	371
Total liabilities	$ 580	$ 490	$ 24	$ 1,094

	Assets and Liabilities with Recurring Fair Value Measures as of December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Cash equivalents[1]	$ 1,306	$ —	$ —	$ 1,306
Margin deposits	413	—	—	413
Commodity instruments:				
Commodity futures contracts	953	—	—	953
Commodity forward contracts[2]	—	204	71	275
Interest rate swaps	—	18	—	18
Total assets	$ 2,672	$ 222	$ 71	$ 2,965
Liabilities:				
Margin deposits held by us posted by our counterparties	$ 9	$ —	$ —	$ 9
Commodity instruments:				
Commodity futures contracts	1,096	—	—	1,096
Commodity forward contracts[2]	—	91	33	124
Interest rate swaps	—	337	—	337
Total liabilities	$ 1,105	$ 428	$ 33	$ 1,566

(1) As of December 31, 2010 and 2009, we had cash equivalents of $1,094 million and $770 million included in cash and cash equivalents and $203 million and $536 million included in restricted cash, respectively.

(2) Includes OTC swaps and options.

The following table sets forth a reconciliation of changes in the fair value of our net derivative assets (liabilities) classified as level 3 in the fair value hierarchy for the years ended December 31, 2010, 2009 and 2008 (in millions):

	2010	2009	2008
Balance, beginning of period	$ 38	$ 105	$ (23)
Realized and unrealized gains (losses):			
Included in net income:			
Included in operating revenues[1]	7	14	78
Included in fuel and purchased energy expense[2]	—	5	(21)
Included in OCI	2	(4)	229
Purchases, issuances and settlements:			
Settlements	(20)	(48)	(97)
Transfers in and/or out of level 3[3]:			
Transfers into level 3[4]	—	—	—
Transfers out of level 3[5]	3	(34)	(61)
Balance, end of period	$ 30	$ 38	$ 105
Change in unrealized gains relating to instruments still held at end of period[2]	$ 7	$ 19	$ 57

(1) For power contracts and Heat Rate swaps and options, as shown on our Consolidated Statements of Operations.

(2) For natural gas contracts, swaps and options, as shown on our Consolidated Statements of Operations.

(3) We transfer amounts among levels of the fair value hierarchy as of the end of each period. There were no significant transfers into/out of level 1 during the years ended December 31, 2010, 2009 and 2008.

(4) There were no significant transfers into level 3 for the years ended December 31, 2010, 2009 and 2008.

(5) Transfers out of level 3 into level 2 were due to changes in market liquidity in various power markets.

8. Derivative Instruments

Types of Derivative Instruments and Volumetric Information

Commodity Instruments — We are exposed to changes in prices for the purchase and sale of power, natural gas and other energy commodities. We use derivatives, which include physical commodity contracts and financial commodity instruments such as OTC and exchange traded swaps, futures, options, forward agreements and instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) for the purchase and sale of power and natural gas to attempt to maximize the risk-adjusted returns by economically hedging a portion of the commodity price risk associated with our assets. By entering into these transactions, we are able to economically hedge a portion of our Spark Spread at estimated generation and prevailing price levels.

Interest Rate Swaps — A portion of our debt is indexed to base rates, primarily LIBOR. We have historically used interest rate swaps to adjust the mix between fixed and floating rate debt to hedge our interest rate risk for potential adverse changes in interest rates.

As of December 31, 2010, the maximum length of our PPAs extend approximately 22 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 2 and 15 years, respectively.

As of December 31, 2010 and 2009, the net forward notional buy (sell) position of our outstanding commodity and interest rate swap contracts that did not qualify under the normal purchase normal sale exemption were as follows (in millions):

	Notional Amounts	
Derivative Instruments	**2010**	**2009**
Power (MWh)	(50)	(52)
Natural gas (MMBtu)	31	78
Interest rate swaps[1]	$ 6,171	$ 7,324

(1) Approximately $3.3 billion of this amount as of December 31, 2010 and approximately $4.3 billion of this amount as of the date of this Report relates to variable rate debt that was converted to fixed rate debt in 2010 and January 2011.

Certain of our derivative instruments contain credit-contingent provisions that require us to maintain our current credit rating or higher from each of the major credit rating agencies. If our credit rating were to be downgraded, it could require us to post additional collateral or could potentially allow our counterparty to request immediate, full settlement on certain derivative instruments in liability positions. Currently, we do not believe that it is probable that any additional collateral posted as a result of a one credit downgrade would be material. The aggregate fair value of our derivative liabilities with credit-contingent provisions as of December 31, 2010, was $39 million for which we have posted collateral of $5 million by posting margin deposits or granted additional first priority liens on the assets currently subject to first priority liens under our First Lien Credit Facility. However, if our credit rating were downgraded, we estimate that additional collateral of $3 million would be required and that no counterparty could request immediate, full settlement.

Accounting for Derivative Instruments

We recognize all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for, and we elect, the normal purchase normal sale exemption. For transactions in which we elect the normal purchase normal sale exemption, gains and losses are not reflected on our Consolidated Statements of Operations until the settlement dates. Revenues and fuel costs derived from instruments that qualify for hedge accounting or represent an economic hedge are recorded in the period and same financial statement line item as the item being hedged. Hedge accounting requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. We present the cash flows from our derivatives in the same category as the item being hedged within operating activities on our Consolidated Statements of Cash Flows unless they contain an other-than-insignificant financing element in which case their cash flows are classified within financing activities.

Cash Flow Hedges — We report the effective portion of the unrealized gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument as a component of OCI and reclassify such gains and losses into earnings in the same period during which the hedged forecasted transaction affects earnings. Gains and losses due to ineffectiveness on commodity hedging instruments are included in unrealized mark-to-market gains and losses and are recognized currently in earnings as a component of operating revenues (for power contracts and Heat Rate swaps and options), fuel and purchased energy expense (for natural gas contracts, swaps and options) and interest expense (for interest rate swaps except as discussed below). If it is determined that the forecasted transaction is no longer probable of occurring, then hedge accounting will be discontinued prospectively and future changes in fair value are recorded in earnings. If the hedging instrument is terminated or de-designated prior to the occurrence of the hedged forecasted transaction, the net accumulated gain or loss associated with the changes in fair value of the hedge instrument remains deferred in OCI until such time as the forecasted transaction impacts earnings, or until it is determined that the forecasted transaction is probable of not occurring.

Derivatives Not Designated as Hedging Instruments — Along with our portfolio of transactions which are accounted for as hedges under U.S. GAAP, we enter into power, natural gas and interest rate transactions that primarily act as economic hedges to our asset and interest rate portfolio, but either do not qualify as hedges under the hedge accounting guidelines or qualify under the hedge accounting guidelines and the hedge accounting designation has not been elected. Changes in fair value of derivatives not designated as hedging instruments are recognized currently in earnings as a component of operating revenues (for power contracts and Heat Rate swaps and options), fuel and purchased energy expense (for natural gas contracts, swaps and options) and interest expense (for interest rate swaps except as discussed below).

Interest Rate Swaps Formerly Hedging our First Lien Credit Facility — During 2010, we repaid approximately $3.5 billion of our First Lien Credit Facility term loans, which had approximately $3.3 billion (notional amount) of interest rate swaps hedging the scheduled variable interest payments under the First Lien Credit Facility term loans, which resulted in the following:

- Upon repayment of the debt, we reclassified the historic unrealized losses of approximately $206 million deferred in AOCI into our income as a separate item described below.
- We performed an evaluation consistent with our risk management policy, and we determined that, based upon current market conditions, liquidation of these interest rate swaps was not economically beneficial, and we elected to retain and hold these interest rate swap positions.
- Additionally, during the fourth quarter, we determined that the variable interest payments remaining on our $1.2 billion of the First Lien Credit Facility term loans that remained outstanding were no longer considered probable to occur, and we de-designated the remaining portion of the interest rate swaps of approximately $1.0 billion (notional amount). At the time of de-designation, the historical unrealized loss was approximately $102 million, which remained in AOCI; however, all future changes in fair value after the de-designation date were recorded into income as a separate item as described below. As of December 31, 2010, approximately $91 million of this loss remained in AOCI.

The reclassification of unrealized losses from AOCI into income, realized swap settlements subsequent to the reclassification date and the changes in fair value subsequent to the reclassification date of the interest rate swaps formerly hedging our First Lien Credit Facility described above totaled approximately $247 million for the year ended December 31, 2010 and is presented separate from interest expense as (gain) loss on interest rate derivatives, net on our Consolidated Statement of Operations.

On January 14, 2011, we repaid the remaining balance under the First Lien Credit Facility term loans with the proceeds received from the issuance of the 2023 First Lien Notes and the unrealized losses related to these interest rate swaps of approximately $91 million remaining in AOCI at December 31, 2010, was reclassified out of AOCI and into income as additional (gain) loss on interest rate derivatives, net in 2011.

Derivatives Included on Our Consolidated Balance Sheet

The following tables present the fair values of our net derivative instruments recorded on our Consolidated Balance Sheets by hedge type and location at December 31, 2010 and 2009 (in millions):

	2010		
	Interest Rate Swaps	Commodity Instruments	Total Derivative Instruments
Balance Sheet Presentation			
Current derivative assets	$ —	$ 725	$ 725
Long-term derivative assets	4	166	170
Total derivative assets	$ 4	$ 891	$ 895
Current derivative liabilities	$ 197	$ 521	$ 718
Long-term derivative liabilities	174	196	370
Total derivative liabilities	$ 371	$ 717	$ 1,088
Net derivative assets (liabilities)	$ (367)	$ 174	$ (193)

	2009		
	Interest Rate Swaps	Commodity Instruments	Total Derivative Instruments
Balance Sheet Presentation			
Current derivative assets	$ —	$ 1,119	$ 1,119
Long-term derivative assets	18	109	127
Total derivative assets	$ 18	$ 1,228	$ 1,246
Current derivative liabilities	$ 202	$ 1,158	$ 1,360
Long-term derivative liabilities	135	62	197
Total derivative liabilities	$ 337	$ 1,220	$ 1,557
Net derivative assets (liabilities)	$ (319)	$ 8	$ (311)

	December 31, 2010		December 31, 2009	
	Fair Value of Derivative Assets	Fair Value of Derivative Liabilities	Fair Value of Derivative Assets	Fair Value of Derivative Liabilities
Derivatives designated as cash flow hedging instruments:				
Interest rate swaps	$ 2	$ 143	$ 18	$ 324
Commodity instruments	161	52	213	80
Total derivatives designated as cash flow hedging instruments	$ 163	$ 195	$ 231	$ 404
Derivatives not designated as hedging instruments:				
Interest rate swaps	$ 2	$ 228	$ —	$ 13
Commodity instruments	730	665	1,015	1,140
Total derivatives not designated as hedging instruments	$ 732	$ 893	$ 1,015	$ 1,153
Total derivatives	$ 895	$ 1,088	$ 1,246	$ 1,557

Derivatives Included on Our Consolidated Statements of Operations

Changes in the fair values of our derivative instruments (both assets and liabilities) are reflected either in cash for option premiums paid or collected, in OCI, net of tax, for the effective portion of derivative instruments which qualify for cash flow hedge accounting treatment, or on our Consolidated Statements of Operations as a component of mark-to-market activity within our net income.

The following tables detail the components of our total mark-to-market activity for both the net realized gain (loss) and the net unrealized gain (loss) recognized from our derivative instruments not designated as hedging instruments and where these components were recorded on our Consolidated Statements of Operations for the years ended December 31, 2010, 2009 and 2008 (in millions):

	2010	2009	2008
Realized gain (loss)			
Interest rate swaps	$ (31)	$ (32)	$ (9)
Commodity derivative instruments[1]	114	37	(146)
Total realized gain (loss)	$ 83	$ 5	$ (155)
Unrealized gain (loss)[2]			
Interest rate swaps	$ (199)	$ 8	$ (11)
Commodity derivative instruments	143	79	35
Total unrealized gain (loss)	$ (56)	$ 87	$ 24
Total mark-to-market activity, net	$ 27	$ 92	$ (131)

(1) Balance includes a non-cash gain from amortization of prepaid power sales agreements of approximately $40 million for the year ended December 31, 2008.

(2) Changes in unrealized gains and losses include de-designation of interest rate swap cash flow hedges and related reclassification from AOCI into income, hedge ineffectiveness and adjustments to reflect changes in credit default risk exposure.

	2010	2009	2008
Realized and unrealized gain (loss)			
Power contracts included in operating revenues	$ (19)	$ 7	$ 232
Natural gas contracts included in fuel and purchased energy expense	276	109	(343)
Interest rate swaps included in interest expense	17	(24)	(20)
Gain (loss) on interest rate derivatives, net	(247)	—	—
Total mark-to-market activity, net	$ 27	$ 92	$ (131)

Derivatives Included in OCI and AOCI

The following table details the effect of our net derivative instruments that qualified for hedge accounting treatment and are included in OCI and AOCI for the years ended December 31, 2010 and 2009 (in millions):

	Gains (Loss) Recognized in OCI (Effective Portion)		Gain (Loss) Reclassified from AOCI into Income (Effective Portion)(2)		Gain (Loss) Reclassified from AOCI into Income (Ineffective Portion)	
	2010	2009	2010	2009	2010	2009
Commodity derivative instruments	$ (27)	$ (280)	$ 248(1)	$ 549(1)	$ —	$ —
Interest rate swaps	193	125	(389)(3)	(214)	—	—
Total	$ 166	$ (155)	$ (141)	$ 335	$ —	$ —

(1) Included in operating revenues and fuel and purchased energy expense on our Consolidated Statement of Operations.

(2) Cumulative net cash flow hedge losses included in AOCI were $122 million and $261 million at December 31, 2010 and 2009.

(3) Reclassification of loss from OCI to earnings made up of $183 million in losses from the reclassification of interest rate contracts due to settlement and $206 million in losses from interest rate contracts reclassified from OCI into earnings due to the refinance of variable rate First Lien Credit Facility term loans.

Assuming constant December 31, 2010 power and natural gas prices and interest rates, we estimate that pre-tax net gains of $19 million would be reclassified from AOCI into earnings during the next 12 months as the hedged transactions settle; however, the actual amounts that will be reclassified will likely vary based on changes in natural gas and power prices as well as interest rates. Therefore, we are unable to predict what the actual reclassification from AOCI into earnings (positive or negative) will be for the next 12 months.

9. Use of Collateral

We use margin deposits, prepayments and letters of credit as credit support with and from our counterparties for commodity procurement and risk management activities. In addition, we have granted additional first priority liens on the assets currently subject to first priority liens under our Corporate Revolving Facility as collateral under certain of our power and natural gas agreements that qualify as "eligible commodity hedge agreements" under our Corporate Revolving Facility and certain of our interest rate swap agreements in order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to the counterparties under such agreements. The counterparties under such agreements would share the benefits of the collateral subject to such first priority liens ratably with the lenders under our First Lien Notes and Corporate Revolving Facility.

The table below summarizes the balances outstanding under margin deposits, natural gas and power prepayments, and exposure under letters of credit and first priority liens for commodity procurement and risk management activities as of December 31, 2010 and 2009 (in millions):

	2010	2009
Margin deposits[1]	$ 162	$ 413
Natural gas and power prepayments	43	34
Total margin deposits and natural gas and power prepayments with our counterparties[2]	$ 205	$ 447
Letters of credit issued[3]	$ 588	$ 353
First priority liens under power and natural gas agreements[4]	—	—
First priority liens under interest rate swap agreements	356	333
Total letters of credit and first priority liens with our counterparties	$ 944	$ 686
Margin deposits held by us posted by our counterparties[1][5]	$ 6	$ 9
Letters of credit posted with us by our counterparties	66	70
Total margin deposits and letters of credit posted with us by our counterparties	$ 72	$ 79

(1) Balances are subject to master netting arrangements and presented on a gross basis on our Consolidated Balance Sheets. We do not offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement for financial statement presentation.

(2) $183 million and $426 million were included in margin deposits and other prepaid expense at December 31, 2010 and 2009, respectively, and $22 million and $21 million were included in other assets at December 31, 2010 and 2009, respectively, on our Consolidated Balance Sheets.

(3) When we entered into our Corporate Revolving Facility on December 10, 2010, the letters of credit issued under our First Lien Credit Facility were either replaced by letters of credit issued by the Corporate Revolving Facility or back-stopped by an irrevocable standby letter of credit issued by Deutsche Bank AG New York Branch. Our letters of credit issued under our Corporate Revolving Facility used for our commodity procurement and risk management activities as of December 31, 2010 include those that were back-stopped of approximately $63 million; however, we expect that the back-stopped letters of credit will be returned and extinguished in early 2011.

(4) The fair value of our commodity derivative instruments collateralized by first priority liens included assets of $193 million and $123 million at December 31, 2010 and 2009, respectively; therefore, there was no collateral exposure at December 31, 2010 and 2009.

(5) Included in other current liabilities on our Consolidated Balance Sheets.

Future collateral requirements for cash, first priority liens and letters of credit may increase or decrease based on the extent of our involvement in hedging and optimization contracts, movements in commodity prices, and also based on our credit ratings and general perception of creditworthiness in our market.

10. Income Taxes

Income Tax Expense (Benefit)

The jurisdictional components of income (loss) from continuing operations before income tax expense (benefit), attributable to Calpine, for the years ended December 31, 2010, 2009 and 2008, are as follows (in millions):

	2010	2009	2008
U.S.	$ (226)	$ 116	$ (52)
International	(4)	13	(30)
Total	$ (230)	$ 129	$ (82)

The components of income tax expense (benefit) from continuing operations for the years ended December 31, 2010, 2009 and 2008, consisted of the following (in millions):

	2010	2009	2008
Current:			
Federal	$ (1)	$ (2)	$ 3
State	10	(2)	3
Foreign	3	3	(66)
Total current	12	(1)	(60)
Deferred:			
Federal	(70)	13	3
State	—	4	1
Foreign	(10)	(1)	—
Total deferred	(80)	16	4
Total income tax expense (benefit)	$ (68)(1)	$ 15	$ (56)

(1) Includes approximately $13 million in intraperiod tax expense related to a prior period.

For the years ended December 31, 2010, 2009 and 2008, our income tax rates did not bear a customary relationship to statutory income tax rates, primarily as a result of the impact of our valuation allowance, state income taxes and changes in unrecognized tax benefits. A reconciliation of the federal statutory rate of 35% to our effective rate from continuing operations for the years ended December 31, 2010, 2009 and 2008, is as follows:

	2010	2009	2008
Federal statutory tax expense (benefit) rate	(35.0)%	35.0%	(35.0)%
State tax expense (benefit), net of federal benefit	2.8	1.0	6.1
Depletion in excess of basis	(1.3)	—	(8.9)
Valuation allowances	33.6	(139.2)	236.8
Foreign taxes	9.9	(9.2)	(57.6)
Non-deductible reorganization items	0.3	1.3	(86.6)
Income from cancellation of indebtedness	—	69.0	32.0
Intraperiod allocation	(40.1)	45.4	(90.9)
Bankruptcy settlement	—	—	(67.7)
Change in unrecognized tax benefits	0.6	1.4	4.3
Permanent differences and other items	(0.4)	6.9	(0.8)
Effective income tax expense (benefit) rate	(29.6)%	11.6%	(68.3)%

Deferred Tax Assets and Liabilities

The components of the deferred income taxes as of December 31, 2010 and 2009, are as follows (in millions):

	2010	2009
Deferred tax assets:		
NOL and credit carryforwards	$ 3,138	$ 3,209
Taxes related to risk management activities and derivatives	18	81
Reorganization items and impairments	422	571
Foreign capital losses	25	68
Other differences	12	10
Deferred tax assets before valuation allowance	3,615	3,939
Valuation allowance	(2,386)	(2,572)
Total deferred tax assets	1,229	1,367
Deferred tax liabilities: property, plant and equipment	(1,280)	(1,417)
Net deferred tax liability	(51)	(50)
Less: Current portion deferred tax asset (liability)	(4)	(8)
Less: Non-current deferred tax asset	30	12
Deferred income tax liability, net of current	$ (77)	$ (54)

For federal income tax reporting purposes, our consolidated U.S. GAAP financial reporting group is comprised primarily of two groups, CCFC and its subsidiaries, which we refer to as the CCFC group, and Calpine Corporation and its subsidiaries other than CCFC, which we refer to as the Calpine group. In 2005, CCFCP issued the CCFCP Preferred Shares, which resulted in the deconsolidation of the CCFC group for income tax purposes. On July 1, 2009, the CCFCP Preferred Shares were redeemed; however, CCFCP continues to be a partnership and therefore, the CCFC group remains deconsolidated from Calpine Corporation for federal income tax reporting purposes. As of December 31, 2010, the CCFC group did not have a valuation allowance recorded against its deferred tax assets due to management's assessment that the CCFC group would more likely than not utilize its NOLs prior to their expiration. In 2011, we may elect to consolidate our CCFC group with our Calpine group for federal income tax purposes. If we elect to consolidate our tax reporting groups, it is reasonably possible that the reversal of the CCFC group deferred tax liabilities with our Calpine group NOLs will allow us to realize more of our Calpine group NOLs, thereby reducing the valuation allowance. Although this election would not significantly impact our tax payments, the result could have a significant impact on our income tax expense reported in 2011.

In accordance with U.S. GAAP, intraperiod tax allocation provisions require allocation of a tax benefit to continuing operations due to current OCI gains and income from discontinued operations. We recorded a tax benefit of $86 million included in our income before discontinued operations on our 2010 Consolidated Statements of Operations, with an offsetting $27 million tax expense in OCI and $59 million tax expense in income from discontinued operations, of which, $5 million is reflected in our current tax expenses and $81 million is reflected in our deferred tax benefit. We recorded a tax expense of $43 million included in our income before discontinued operations on our 2009 Consolidated Statements of Operations, with an offsetting $43 million deferred tax benefit in OCI and nil in income from discontinued operations. We recorded a tax benefit of $90 million included in our loss before discontinued operations on our 2008 Consolidated Statements of Operations with an offsetting $76 million tax expense in OCI and a $14 million tax expense in income from discontinued operations.

NOL Carryforwards — Our NOL carryforwards consist primarily of federal NOL carryforwards of approximately $7.4 billion, which consists of approximately $6.9 billion from the Calpine group and approximately $472 million from the CCFC group, and expire between 2023 and 2029, and state NOL carryforwards of approximately $4.4 billion, which expire between 2011 and 2030, substantially all of which are offset with a full valuation allowance. The NOL carryforwards available are subject to limitations on their annual usage. Under federal and applicable state income tax laws, a corporation is generally permitted to deduct from taxable income in any year NOLs carried forward from prior years subject to certain time limitations as prescribed by the taxing authorities. We also have approximately $1.0 billion in foreign NOLs, substantially all of which are offset with a full valuation allowance.

Under federal income tax law, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of the IRC. We experienced an ownership change on the Effective Date as a result of the cancellation of our old common stock and the distribution of our new common stock pursuant to our Plan of Reorganization. However, this ownership change and resulting annual limitations are not expected to result in the expiration of our NOL carryforwards if we are able to generate sufficient future taxable income within the carryforward periods.

As of December 31, 2010, approximately $2.5 billion of our $7.4 billion total NOLs remain subject to annual section 382 limitations with the remaining $4.9 billion no longer subject to the Section 382 limitation.

If a subsequent ownership change were to occur as a result of future transactions in our stock, accompanied by a significant reduction in our market value immediately prior to the ownership change, our ability to utilize the NOL carryforwards may be significantly limited, including the $4.9 billion of federal NOLs that are not limited by Section 382.

Under state income tax laws, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of the IRC. We are analyzing the effect of our change in ownership on the Effective Date for each of our significant states to determine the amount of our NOL limitation. The analysis will also determine our state NOLs expected to expire unutilized as a result of the cessation of business operations and changes in apportionment as of the Effective Date. Although our analysis is not complete, we believe that the statutory limitations on the use of some of our pre-emergence state NOLs will cause them to expire unutilized. We believe our analysis could result in a significant reduction of available state NOLs, which had a full valuation allowance as of December 31, 2010 and 2009. Upon completion, of the analysis, we will reduce our deferred tax asset for state NOLs that we are unable to utilize and make an equal reduction in our valuation allowance. The result should not have an effect on our income tax expense in 2011.

The State of California enacted legislation in 2010 suspending the ability of taxpayers to use NOLs for tax years 2010 and 2011; however, they have extended the 20 year carryforward period to account for the suspension period. As a result of the California NOL suspension, our income tax expense increased by approximately $3 million in 2010.

To manage the risk of significant limitations on our ability to utilize our tax NOL carryforwards, our amended and restated certificate of incorporation permits our Board of Directors to meet to determine whether to impose certain transfer restrictions on our common stock if, prior to February 1, 2013, our Market Capitalization declines by at least 35% from our Emergence Date Market Capitalization of approximately $8.6 billion (in each case, as defined in and calculated pursuant to our amended and restated certificate of incorporation) and at least 25 percentage points of shift in ownership has occurred with respect to our equity for purposes of Section 382 of the IRC. As of the filing of this Report, neither circumstance has been met. While we don't believe an ownership change of 25 percentage points has occurred, the change in ownership is only slightly less than 25%. Accordingly, the transfer restrictions have not been put in place by our Board of Directors; however, if both of the foregoing events were to occur together and our Board of Directors were to elect to impose these restrictions, they could become operative in the future. There can be no assurance that the circumstances will not be met in the future, or in the event that they are met, that our Board of Directors would choose to impose these restrictions or that, if imposed, such restrictions would prevent an ownership change from occurring.

Should our Board of Directors elect to impose these restrictions, they shall have the authority and discretion to determine and establish the definitive terms of the transfer restrictions provided that they apply to purchases by owners of 5% or more of our common stock including any owners who would become owners of 5% or more of our common stock via such purchase. The transfer restrictions will not apply to the disposition of shares provided they are not purchased by a 5% or more owner.

Valuation Allowance — U.S. GAAP requires that we consider all available evidence, both positive and negative, and tax planning strategies to determine whether, based on the weight of that evidence, a valuation allowance is needed to reduce the value of deferred tax assets. Future realization of the tax benefit of an existing deductible temporary difference or carryforward ultimately depends on the existence of sufficient taxable income of the appropriate character within the carryback or carryforward periods available under the tax law. Due to our history of losses, we were unable to assume future profits; however, since our emergence from Chapter 11, we are able to consider available tax planning strategies.

As of December 31, 2010, we have provided a valuation allowance of approximately $2.4 billion on certain federal, state and foreign tax jurisdiction deferred tax assets to reduce the amount of these assets to the extent necessary to result in an amount that is more likely than not to be realized. The net change in our valuation allowance was a decrease of $186 million for the year ended December 31, 2010, and a decrease of $113 million and an increase of $284 million for the years ended December 31, 2009 and 2008, respectively; all primarily related to changes in our estimates of our ability to utilize our NOL carryforwards.

Unrecognized Tax Benefits

As of December 31, 2010, we had unrecognized tax benefits of $88 million. If recognized, $41 million of our unrecognized tax benefits could impact the annual effective tax rate and $47 million related to deferred tax assets, which if realized, could be offset by a corresponding change in the recorded valuation allowance resulting in no impact to our effective tax rate. We also had accrued interest and penalties of $19 million for income tax matters as of December 31, 2010. The amount of unrecognized tax benefits decreased by $10 million for the year ended December 31, 2010, primarily as a result of a decrease of $9 million related to a hedging position terminated for CCFC group, a decrease of $2 million related to depreciation taken on a position for a capitalized asset and an increase of $1 million related to state and other adjustments. The decrease is related to temporary differences in tax reporting and did not impact the annual effective tax rate. We believe it is reasonably possible that a decrease of approximately $14 million in unrecognized tax benefits could occur within next 12 months primarily related to federal tax liabilities and federal interest and penalties.

A reconciliation of the beginning and ending amounts of our unrecognized tax benefits for the years ended December 31, 2010 and 2009, is as follows (in millions):

	2010	2009	2008
Balance, beginning of period	$ (98)	$ (90)	$ (173)
Increases related to prior year tax positions	(1)	(11)	(2)
Decreases related to prior year tax positions	11	2	6
Increases related to current year tax positions	—	—	(7)
Settlements	—	1	84
Decrease related to lapse of statute of limitations	—	—	2
Balance, end of period	$ (88)	$ (98)	$ (90)

11. Earnings (Loss) per Share

Pursuant to our Plan of Reorganization, all shares of our common stock outstanding prior to the Effective Date were canceled and the issuance of 485 million new shares of reorganized Calpine Corporation common stock was authorized to resolve allowed unsecured claims. A portion of the 485 million authorized shares was immediately distributed, and the remainder was reserved for distribution to holders of certain disputed claims that, although allowed as of the Effective Date, are unresolved. To the extent that any of the reserved shares remain undistributed upon resolution of the disputed claims, such shares will not be returned to us but rather will be distributed pro rata to claimants with allowed claims to increase their recovery. Therefore, pursuant to our Plan of Reorganization, all 485 million shares ultimately will be distributed. Accordingly, although the reserved shares are not yet issued and outstanding, all conditions of distribution had been met for these reserved shares as of the Effective Date, and such shares are considered issued and are included in our calculation of weighted average shares outstanding. We also include restricted stock units for which no future service is required as a condition to the delivery of the underlying common stock in our calculation of weighted average shares outstanding.

Reconciliations of the amounts used in the basic and diluted earnings (loss) per common share computations for the years ended December 31, 2010, 2009 and 2008, are as follows (shares in thousands):

	2010	2009	2008
Diluted weighted average shares calculation:			
Weighted average shares outstanding (basic)	486,044	485,659	485,054
Share-based awards	1,250	660	492
Weighted average shares outstanding (diluted)	487,294	486,319	485,546

We excluded the following items from diluted earnings (loss) per common share for the years ended December 31, 2010, 2009 and 2008 because they were anti-dilutive (shares in thousands):

	2010	2009	2008
Share-based awards	14,883	13,158	7,259
Common stock warrants(1)	—	—	29,158

(1) Pursuant to our Plan of Reorganization, holders of allowed interests (primarily holders of our old common stock canceled on the Effective Date) received a pro rata share of warrants to purchase approximately 48.5 million shares of our new, reorganized Calpine Corporation common stock at $23.88 per share. Warrants for 21,499 shares of common stock were exercised prior to expiration. The remaining warrants expired unexercised on August 25, 2008.

12. Stock-Based Compensation

Calpine Equity Incentive Plans

The Calpine Equity Incentive Plans were approved as part of our Plan of Reorganization. These plans are administered by the Compensation Committee of our Board of Directors and provide for the issuance of equity awards to all employees as well as the non-employee members of our Board of Directors. The equity awards may include incentive or non-qualified stock options, restricted stock, restricted stock units, stock appreciation rights, performance compensation awards, and other stock-based awards.

On May 19, 2010, our shareholders, upon the recommendation of our Board of Directors, approved the amendment to the Director Plan to increase the aggregate number of shares of common stock authorized for issuance under the Director Plan by 400,000 shares and to extend the term of the Director Plan to January 31, 2018, and approved the amendment to the Equity Plan to increase the aggregate number of shares of common stock authorized for issuance under the Equity Plan by 12,700,000 shares. Subsequent to the amendments of the Director Plan and Equity Plan, there are 567,000 and 27,533,000 shares, respectively, of our common stock authorized for issuance to participants.

The equity awards granted under the Calpine Equity Incentive Plans include both graded and cliff vesting options, which vest over periods between one and five years, contain contractual terms of seven and ten years and are subject to forfeiture provisions under certain circumstances, including termination of employment prior to vesting. Employment inducement options to purchase a total of 4,636,734 shares were granted outside of the Calpine Equity Incentive Plans in connection with our hiring of our current executive management team in 2008; however, no grants of options or shares of restricted stock were made outside of the Calpine Equity Incentive Plans during the years ended December 31, 2010 and 2009.

On August 11, 2010, we awarded stock options to purchase an aggregate of 3,260,000 shares of our common stock to certain executive officers under the Equity Plan. These stock options provide a generally competitive compensation opportunity for the current or a similar economic environment that was intended in their original employment inducement, but contain a market condition to reduce in number as, and if, our common stock prices return to historical pricing levels. Specifically, if on the date of exercise of the stock options, the closing price of our common stock exceeds the exercise price plus 25% ($15.80), then the number of shares underlying the stock options that may be exercised on that date of exercise shall be reduced, on a straight-line basis, beginning when the closing price on the date of exercise exceeds $15.80 and ending when such closing price equals or exceeds $27.50 per share at which price the number of shares underlying the stock options shall be reduced to zero shares. The stock options contain a cliff vesting term of approximately three years and expiration coincides with the expiration of each executive officer's respective employment inducement options, or expires upon a termination of employment. Due to the market condition contained in the option agreements (described above), these options are valued using the Monte Carlo simulation model.

We use the Black-Scholes option-pricing model or the Monte Carlo simulation model to estimate the fair value of our employee stock options on the grant date, which takes into account the exercise price and expected term of the stock option, the current price of the underlying stock and its expected volatility, expected dividends on the stock, and the risk-free interest rate for the expected term of the stock option as of the grant date. For our restricted stock and restricted stock units, we use our closing stock price on the date of grant, or the last trading day preceding the grant date for restricted stock granted on non-trading days, as the fair value for measuring compensation expense. Stock-based compensation expense is recognized over the period in which the related employee services are rendered. The service period is generally presumed to begin on the grant date and end when the equity award is fully vested. We use the graded vesting attribution method to recognize fair value of the equity award over the service period. For example, the graded vesting attribution method views one three-year option grant with annual graded vesting as three separate sub-grants, each representing 33 1/3% of the total number of stock options granted. The first sub-grant vests over one year, the second sub-grant vests over two years and the third sub-grant vests over three years. A three-year option grant with cliff vesting is viewed as one grant vesting over three years.

Stock-based compensation expense recognized was $24 million, $38 million and $50 million for the years ended December 31, 2010, 2009 and 2008, respectively. We did not record any tax benefits related to stock-based compensation expense in any period as we are not benefiting from a significant portion of our deferred tax assets, including deductions related to stock-based compensation expense. In addition, we did not capitalize any stock-based compensation expense as part of the cost of an asset for the years ended December 31, 2010, 2009 and 2008. At December 31, 2010, there was unrecognized compensation cost of $20 million related to options, $12 million related to restricted stock and nil related to restricted stock units, which is expected to be recognized over a weighted average period of 1.9 years for options, 1.6 years for restricted stock and 0.4 years for restricted stock units. We issue new shares from our reserves set aside for the Calpine Equity Incentive Plans and employment inducement options when stock options are exercised and for other stock-based awards.

A summary of all of our non-qualified stock option activity for the Calpine Equity Incentive Plans for the year ended December 31, 2010, is as follows:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding — December 31, 2009	13,232,519	$ 19.09	6.6	$ 2
Granted	4,650,124	$ 12.30		
Exercised	11,735	$ 7.77		
Forfeited	402,016	$ 12.42		
Expired	304,002	$ 17.45		
Outstanding — December 31, 2010	17,164,890	$ 17.44	5.6	$ 8
Exercisable — December 31, 2010	6,234,555	$ 19.23	5.7	$ 1
Vested and expected to vest – December 31, 2010	16,889,383	$ 17.55	5.6	$ 8

The total intrinsic value and the cash proceeds received from our employee stock options exercised were not significant for the year ended December 31, 2010. There were no employee stock options exercised during the years ended December 31, 2009 and 2008.

The fair value of options granted during the years ended December 31, 2010, 2009 and 2008, was determined on the grant date using the Black-Scholes pricing model or the Monte Carlo simulation model, as appropriate. Certain assumptions were used in order to estimate fair value for options as noted in the following table.

	2010	2009	2008
Expected term (in years)(1)	4.0 – 6.5	6.0 – 6.5	5.0 – 6.1
Risk-free interest rate(2)	1.3 – 3.3%	2.3 – 2.9 %	1.0 – 3.3 %
Expected volatility(3)	31.4 – 37.6%	52.1 – 73.0%	34.8 – 98.0%
Dividend yield(4)	—	—	—
Weighted average grant-date fair value (per option)	$ 1.98	$ 5.67	$ 6.48

(1) Expected term calculated using the simplified method prescribed by the SEC due to the lack of sufficient historical exercise data to provide a reasonable basis to estimate the expected term.

(2) Zero Coupon U.S. Treasury rate or equivalent based on expected term.

(3) For the years ended December 31, 2010 and 2009, we calculated volatility using the implied volatility of our exchange traded stock options. For the year ended December 31, 2008, we calculated volatility using the weighted average implied volatility of our industry peers' exchange traded options.

(4) We have never paid cash dividends on our common stock, and it is not anticipated that any cash dividends will be paid on our common stock in the near future.

No restricted stock or restricted stock units have been granted other than under the Calpine Equity Incentive Plans. A summary of our restricted stock and restricted stock unit activity for the Calpine Equity Incentive Plans for the year ended December 31, 2010, is as follows:

	Number of Restricted Stock Awards	Weighted Average Grant-Date Fair Value
Nonvested — December 31, 2009	2,046,599	$ 11.95
Granted	1,475,992	$ 11.32
Forfeited	400,141	$ 11.11
Vested	439,333	$ 15.47
Nonvested — December 31, 2010	2,683,117	$ 11.16

The total fair value of our restricted stock that vested during the years ended December 31, 2010, 2009 and 2008, was $4 million, $8 million and $3 million, respectively.

13. Defined Contribution and Defined Benefit Plans

We maintain two defined contribution savings plans that are intended to be tax exempt under Sections 401(a) and 501(a) of the IRC. Our non-union plan generally covers employees who are not covered by a collective bargaining agreement, and our union plan covers employees who are covered by a collective bargaining agreement. We recorded expenses for these plans of $9 million, $9 million and $10 million for the years ended December 31, 2010, 2009 and 2008, respectively. Employer matching contributions are 100% of the first 5% of compensation a participant defers for the non-union plan. The employee deferral limit is 75% of compensation under both plans.

As part of the Conectiv Acquisition, we assumed approximately $6 million of pension liability for 129 union employees that were retained as part of the Conectiv Acquisition and enrolled them into the New Development Holdings, LLC Union Retirement Plan, a defined benefit plan. PHI retained the pension liability associated with past service cost; however we are responsible for benefits for services after July 1, 2010 and future compensation increases related to past service. Under the New Development Holdings, LLC Union Retirement Plan, retirement benefits are primarily a function of age attained, years of participation, years of service, vesting and level of compensation. As of December 31, 2010, our pension assets, liabilities and related costs were not material to us. There was approximately $8 million in plan assets and approximately $15 million in pension liabilities. Our net pension liability recorded on our Consolidated Balance Sheet as of December 31, 2010 was approximately $7 million. During 2010, we recognized net periodic benefit costs of approximately $9 million, which includes a one-time charge to pension expense for a voluntary, early retirement offer of approximately $8 million. The voluntary, early retirement offer was accepted by 31 of the 48 eligible employees that were retained as part of the Conectiv Acquisition allowing these employees the ability to commence receiving retirement benefits early without reducing their overall pension benefits. Our net period benefit cost is included in plant operating expense in our Consolidated Statements of Operations. The total amount recognized in AOCI for 2010 was nil.

In making our estimates of our pension obligation and related costs, we utilize discount rates, rates of compensation increases and rates of return on our assets that we believe are reasonable. Due to relatively small size of our pension liability (which is not considered material), significant changes in these assumptions would not have a material effect on our pension liability. During 2010, we made contributions of approximately $8 million, and estimated contributions to the pension plan are expected to be approximately $2 million in 2011. Estimated future benefit payments to participants in each of the next five years are expected to be less than $1 million in each year.

14. Capital Structure

Common Stock

Pursuant to our Plan of Reorganization, all shares of our common stock outstanding prior to the Effective Date were canceled, and we authorized the issuance of 485 million new shares of reorganized Calpine Corporation common stock. As of December 31, 2010, approximately 441 million shares have been distributed to holders of allowed unsecured claims and approximately 44 million shares remain in reserve for distribution to holders of disputed claims whose claims ultimately become allowed. See Notes 15 and 18 for further discussion of the shares of reorganized Calpine Corporation common stock.

Our authorized common stock consists of 1.4 billion shares of Calpine Corporation common stock. Common stock issued as of December 31, 2010 and 2009, was 444,883,356 shares and 443,325,827 shares, respectively, at a par value of $0.001 per share. Common stock outstanding as of December 31, 2010 and 2009, was 444,435,198 shares and 442,998,255 shares, respectively.

The table below summarizes our common stock activity since our emergence from Chapter 11 on the Effective Date. All shares of our common stock outstanding prior to the Effective Date were canceled and common stock activity prior to the Effective Date is not presented below as it is no longer meaningful.

	Shares Issued	Shares Held in Treasury	Shares Held in Reserve	Inter-Creditor Disputes	Total
Implementation of our Plan of Reorganization	410,992,508	—	64,255,231	9,752,261	485,000,000
Resolution of claims	16,093,028	—	(16,093,028)	—	—
Exercise of warrants	21,499	—	—	—	21,499
Restricted stock, net of forfeitures	1,739,522	—	—	—	1,739,522
Vested restricted stock	178,500	(65,032)	—		113,468
Balance at December 31, 2008	429,025,057	(65,032)	48,162,203	9,752,261	486,874,489
Resolution of claims/inter-creditor disputes	13,167,420	—	(3,415,159)	(9,752,261)	—
Restricted stock, net of forfeitures	230,161	—	—	—	230,161
Vested restricted stock	903,189	(262,540)	—	—	640,649
Balance at December 31, 2009	443,325,827	(327,572)	44,747,044	—	487,745,299
Resolution of claims	488,612	—	(488,612)	—	—
Restricted stock, net of forfeitures	668,865	—	—	—	668,865
Vested restricted stock	352,305	(120,586)	—	—	231,719
Restricted stock units released	36,012	—	—	—	36,012
Shares issued from option exercises	11,735	—	—	—	11,735
Balance at December 31, 2010	444,883,356	(448,158)	44,258,432	—	488,693,630

Treasury Stock

As of December 31, 2010 and 2009, we had treasury stock of 448,158 shares and 327,572 shares, respectively, with a cost of $5 million and $3 million, respectively, which consists of our common stock withheld to satisfy federal, state and local income tax withholding requirements for vested employee restricted stock awards.

15. Commitments and Contingencies

Long-Term Service Agreements

As of December 31, 2010, the total estimated commitments for LTSAs associated with turbines installed or in storage were approximately $77 million. These commitments are payable over the terms of the respective agreements, which range from 1 to 7 years. LTSA future commitment estimates are based on the stated payment terms in the contracts at the time of execution and are subject to an annual inflationary adjustment. Certain of these agreements have terms that allow us to cancel the contracts for a fee. If we cancel such contracts, the estimated commitments remaining for LTSAs would be reduced.

Power Plant Operating Leases

We have entered into certain long-term operating leases for power plants, extending through 2020, including renewal options. Some of the lease agreements provide for renewal options at fair value, and some of the agreements contain customary restrictions on dividends, additional debt and further encumbrances similar to those typically found in project finance agreements. Payments on our operating leases, which may contain escalation clauses or step rent provisions, are recognized on a straight-line basis. Certain capital improvements associated with leased power plants may be deemed to be leasehold improvements and are amortized over the shorter of the term of the lease or the economic life of the capital improvement. Future minimum lease payments under these leases are as follows (in millions):

	Initial Year	2011	2012	2013	2014	2015	Thereafter	Total
Greenleaf	1998	$ 7	$ 7	$ 7	$ 2	$ —	$ —	$ 23
KIAC	2000	25	24	24	24	23	96	216
Total		$ 32	$ 31	$ 31	$ 26	$ 23	$ 96	$ 239

During the years ended December 31, 2010, 2009 and 2008, rent expense for power plant operating leases amounted to $45 million, $47 million and $46 million, respectively.

Production Royalties and Leases

We are obligated 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 or adjusted based on consumer price index changes and are not material. Under the terms of most geothermal leases, the royalties accrue as a percentage of power revenues. Certain properties also have net profits and overriding royalty interests that are in addition to the land base lease royalties. Some 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 geothermal power plants for the years ended December 31, 2010, 2009 and 2008, were $25 million, $22 million and $33 million, respectively.

Office and Equipment Leases

We lease our corporate and regional offices, as well as some of our office equipment, under noncancellable operating leases extending through 2020. Future minimum lease payments under these leases are as follows (in millions):

2011	$ 11
2012	10
2013	9
2014	6
2015	5
Thereafter	11
Total	$ 52

Lease payments are subject to adjustments for our pro rata portion of annual increases or decreases in building operating costs. During the years ended December 31, 2010, 2009 and 2008, rent expense for noncancellable operating leases was $12 million, $12 million and $14 million, respectively.

Natural Gas Purchases

We enter into natural gas purchase contracts of various terms with third parties to supply natural gas to our natural gas-fired power plants. The majority of our purchases are made in the spot market or under index-priced contracts. At December 31, 2010, we had future commitments of approximately $4.9 billion for natural gas purchases under contracts with terms from 1 to 16 years, and one contract with a term of 31 years.

Guarantees and Indemnifications

As part of our normal business operations, we enter into various agreements providing, or otherwise arranging, financial or performance assurance to third parties on behalf of our subsidiaries in the ordinary course of such subsidiaries' respective business. Such arrangements include guarantees, standby letters of credit and surety bonds for power and natural gas purchase and sale arrangements and contracts associated with the development, construction, operation and maintenance of our fleet of power plants. These arrangements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes.

At December 31, 2010, guarantees of subsidiary debt, standby letters of credit and surety bonds to third parties and guarantees of subsidiary operating lease payments and their respective expiration dates were as follows (in millions):

Guarantee Commitments	2011	2012	2013	2014	2015	Thereafter	Total
Guarantee of subsidiary debt(1)	$ 78	$ 77	$ 72	$ 318	$ 36	$ 271	$ 852
Standby letters of credit(2)(4)	601	91	—	—	—	19	711
Surety bonds(3)(4)(5)	—	—	—	—	—	5	5
Total	$ 679	$ 168	$ 72	$ 318	$ 36	$ 295	$ 1,568

(1) Represents Calpine Corporation guarantees of certain project debt, power plant capital leases and related interest. All guaranteed capital leases are recorded on our Consolidated Balance Sheets.

(2) The standby letters of credit disclosed above represent those disclosed in Note 6.

(3) The majority of surety bonds do not have expiration or cancellation dates.

(4) These are off balance sheet obligations.

(5) As of December 31, 2010, $4 million of cash collateral is outstanding related to these bonds.

We routinely arrange for the issuance of letters of credit and various forms of surety bonds to third parties in support of our subsidiaries' contractual arrangements of the types described above and may guarantee the operating performance of some of our partially owned subsidiaries up to our ownership percentage. The letters of credit issued under various credit facilities support CES risk management and other operational and construction activities. In the event a subsidiary were to fail to perform its obligations under a contract supported by such a letter of credit or surety bond, and the issuing bank or surety were to make payment to the third party, we would be responsible for reimbursing the issuing bank or surety within an agreed timeframe, typically a period of one to ten days. To the extent liabilities are incurred as a result of activities covered by letters of credit or the surety bonds, such liabilities are included on our Consolidated Balance Sheets.

Commercial Agreements — In connection with the purchase and sale of power, natural gas and emission allowances to and from third parties with respect to the operation of our power plants, we may be required to guarantee a portion of the obligations of certain of our subsidiaries. These guarantees may include future payment obligations as well as operational performance guarantees and effectively guarantee our future performance under certain agreements.

Purchase and Sale Agreements — In connection with our purchase and sale agreements, we have frequently provided for indemnification by each of the purchaser and the seller, and/or their respective parent, to the counterparty for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party. These indemnification obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or impossible to quantify at the time of the consummation of a particular transaction.

Other — Additionally, we and our subsidiaries from time to time assume other guarantee and indemnification obligations in conjunction with other transactions such as parts supply agreements, construction agreements and equipment lease agreements. These guarantee and indemnification obligations may include future payment obligations and effectively guarantee our future performance under certain agreements.

Our potential exposure under guarantee and indemnification obligations can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. Our total maximum exposure under our guarantee and indemnification obligations is not estimable due to uncertainty as to whether claims will be made or how any potential claim will be resolved. As of December 31, 2010, there are no outstanding claims related to our guarantee and indemnification obligations and we do not anticipate that we will be required to make any material payments under our guarantee and indemnification obligations.

Litigation

We are party to various litigation matters, including regulatory and administrative proceedings arising out of the normal course of business, the more significant of which are summarized below. The ultimate outcome of each of these matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome be reasonably estimated presently for every case. The liability we may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters and, as a result of these matters, may potentially be material to our financial position or results of operations. We review our litigation activities and determine if an unfavorable outcome to us is considered "remote," "reasonably possible" or "probable" as defined by U.S. GAAP. Where we have determined an unfavorable outcome is probable and is reasonably estimable, we have accrued for potential litigation losses. Following the Effective Date, pending actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date, as well as pending litigation against the U.S. Debtors related to such liabilities, generally have been permanently enjoined. Any unresolved claims will continue to be subject to the claims reconciliation process under the supervision of the U.S. Bankruptcy Court. However, certain pending litigation related to pre-petition liabilities may proceed in courts other than the U.S. Bankruptcy Court to the extent the parties to such litigation have obtained relief from the permanent injunction. In particular, certain pending actions against us are anticipated to proceed as described below. In addition to the other matters described below, we are involved in various other claims and legal actions, including regulatory and administrative proceedings arising out of the normal course of our business. We do not expect that the outcome of such other claims and legal actions will have a material adverse effect on our financial position or results of operations.

Pit River Tribe, et al. v. Bureau of Land Management, et al. — On June 17, 2002, the Pit River Tribe filed suit against the BLM and other federal agencies in the U.S. District Court for the Eastern District of California seeking to enjoin further exploration, construction and development of the Calpine Fourmile Hill Project in the Glass Mountain and Medicine Lake geothermal areas. The complaint challenged the validity of the decisions of the BLM and the U.S. Forest Service to permit the development of the proposed project under two geothermal mineral leases previously issued by the BLM. The lawsuit also sought to invalidate the leases. Only declaratory and equitable relief was sought.

On November 5, 2006, the U.S. Court of Appeals for the Ninth Circuit issued a decision granting the plaintiffs relief by holding that the BLM had not complied with the National Environmental Policy Act, and other procedural requirements and, therefore, held that the lease extensions were invalid. The Ninth Circuit remanded the matter back to the U.S. District Court to implement its decision. On December 22, 2008, the District Court in turn remanded this matter back to federal agencies for curative action, including whether the leases may be extended. Before the agencies could reconsider, the Pit River Tribe appealed the District Court's decision on the basis the original Ninth Circuit decision purportedly invalidated the leases, and therefore, the Pit River Tribe argues, the Ninth Circuit did not give the District Court latitude to grant an extension of the leases. Oral argument on the Tribe's appeal was held in the Ninth Circuit on March 10, 2010. On August 2, 2010, the Ninth

Circuit ruled in favor of BLM and Calpine Corporation, concluding that the BLM may properly reconsider its decision to extend the term of our two Four-Mile Hill leases. The Pit River Tribe did not file a petition of certiorari to the U.S. Supreme Court seeking review of the Ninth Circuit opinion. Accordingly, on November 4, 2010, the United States District for the Eastern District of California entered an order remanding the matter to federal agencies to implement the Court's order.

In addition, in May 2004, the Pit River Tribe and other interested parties filed two separate suits in the District Court seeking to enjoin exploration, construction, and development of the Telephone Flat leases and proposed project at Glass Mountain. These two related cases continue to be subject to the discharge injunction as described in the Confirmation Order. Similar to above, we are now in communication with the U.S. Department of Justice regarding these two cases, but the cases have remained mostly inactive pending the outcome of the above described Pit River Tribe case. Now that the above Pit River Tribe case has been resolved, we anticipate the Pit River Tribe and other interested parties may seek to reactivate the two additional suits.

Sonoma County, California Property Taxes — We have received notification from the Sonoma County Assessor that certain of our geothermal power plants properties have been reassessed at a greater property value as a result of the unwinding in 2006 of financing lease transactions. We disagree with the reassessment and the value, and we believe any right to retroactive reassessment is precluded by the determinations in our bankruptcy proceedings. We have asked the Bankruptcy Court, which retains jurisdiction over certain pre-emergence matters, for a ruling precluding the retroactive reassessment. To the extent, if any, it is not precluded, we intend to vigorously contest the reassessment in the Sonoma County assessment and through appeal to the courts. We cannot rule out the possibility of an unfavorable outcome, but we do not expect an adverse outcome to have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Environmental Matters

We are subject to complex and stringent environmental laws and regulations related to the operation of our power plants. On occasion, we may incur environmental fees, penalties and fines associated with the normal operation of our power plants. We do not, however, have environmental violations or other matters that would have a material impact on our financial condition, results of operations or cash flows or that would significantly change our operations. A summary of our larger environmental matters are as follows:

Environmental Remediation of Certain Assets Acquired from Conectiv — As part of the Conectiv Acquisition on July 1, 2010, we assumed environmental remediation liabilities related to certain of the assets located in New Jersey that are subject to the ISRA. We have accrued approximately $8 million in liabilities as of December 31, 2010, and could incur expenditures related thereto of up to $10 million. Pursuant to the Conectiv Purchase Agreement, PHI is responsible for any amounts that exceed $10 million. Until our acquisition accounting is finalized for the Conectiv Acquisition, any future changes to our environmental remediation liabilities, if any, are not expected to impact future earnings, but would be reflected in our allocation of the Conectiv Acquisition purchase price. See Note 3 for disclosures related to our Conectiv Acquisition. We have engaged a licensed site remediation professional who has evaluated the recognized environmental conditions and is conducting site investigations in accordance with ISRA requirements as a precursor to developing the ultimate cleanup plan.

Heat Input Limits at Deepwater Unit 1 — Prior to our acquisition, Conectiv was a party to certain pending penalty proceedings in the administrative courts of the State of New Jersey involving one of the older peaker power plants (Deepwater Unit 1). The NJDEP alleged that Deepwater Unit 1 had exceeded its permissible maximum heat input limit, which restricts the amount of fuel burned. Heat input limits are imposed on power plants without emissions monitoring equipment to limit emissions of pollutants that are not subject to measurement by continuous emissions monitoring systems. Appeals were filed in 2007, and a status hearing has been set for later this year. The appeals assert that the NJDEP does not have the authority to limit heat input in Title V air permits. We plan to continue to work with the NJDEP to ensure that our New Jersey assets may operate at full capacity. Currently, these restrictions require one of our peaker power plants (Deepwater Unit 1) to operate at approximately 8 MW less than its full capacity of 86 MW. We are preparing an application to modify the Deepwater Unit 1 air permit to reclaim the 8 MW limitation, but there can be no assurance that our application will be successful.

Other Contingencies

Distribution of Calpine Common Stock under our Plan of Reorganization — Through the filing of this Report, approximately 441 million shares have been distributed to holders of allowed unsecured claims and approximately 44 million shares remain in reserve for distribution to holders of disputed claims whose claims ultimately become allowed under our Plan of Reorganization. See also Note 18 for further information related to our Plan of Reorganization and emergence from Chapter 11. To the extent that any of the reserved shares remain undistributed upon resolution of the remaining disputed claims, such shares will not be returned to us but rather will be distributed pro rata to claimants with allowed claims to increase their recovery. We are not required to issue additional shares above the 485 million shares authorized to settle unsecured claims, even if the shares remaining for distribution are not sufficient to fully pay all allowed unsecured claims. However, certain disputed claims, including prepayment premium and default interest claims asserted by the holders of CalGen Third Lien Debt, may be required to be settled with available cash and cash equivalents to the extent reorganized Calpine Corporation common stock held in reserve pursuant to our Plan of Reorganization for such claims is insufficient in value to satisfy such claims in full. We consider such an outcome to be unlikely. To the extent that holders of the CalGen Third Lien Debt have claims that remain unsettled or outstanding, they assert that they continue to have lien rights to the assets of the CalGen entities until the pending claims asserted in the case styled: *HSBC Bank USA, NA as Indenture Trustee, et al v. Calpine Corporation, et al. Case No. 1: 07-cv-03088, S.D.N.Y.* are resolved either through court action or settlement. We dispute such allegations and contend that all liens were released when the CalGen secured claims were paid in full under the terms of applicable court orders and our Plan of Reorganization as confirmed. Recently the district court in the above litigation issued a decision that the holders of the CalGen Third Lien Debt were not entitled, as a matter of law, to a prepayment premium or to attorney's fees associated with the payoff of the underlying obligations. Further, the district court determined that the holders of the CalGen Third Lien Debt were only entitled to interest as specified in the supporting debt agreements, but did not rule on the issue of entitlement to default interest on their claims. We believe the holders of the CalGen Third Lien Debt will file an appeal of the judgment entered by the district court. We continue to engage in settlement discussions with the various constituencies in this dispute.

16. Segment and Significant Customer Information

We assess our business on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and other factors impacting supply and demand. Our reportable segments are West (including geothermal), Texas, North (including Canada and the assets purchased in the Conectiv Acquisition) and Southeast. We continue to evaluate the optimal manner in which we assess our performance including our segments and future changes may result.

Commodity Margin includes our power and steam revenues, sales of purchased power and natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, RGGI compliance and other environmental costs, and cash settlements from our marketing, hedging and optimization activities that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenues. Commodity Margin is a key operational measure reviewed by our chief operating decision maker to assess the performance of our segments.

The tables below show our financial data for our segments for the periods indicated (in millions). Our North segment information for the year ended December 31, 2010, includes the financial results of the assets we acquired from Conectiv beginning on the acquisition date of July 1, 2010, with no similar revenues and expenses included for the years ended December 31, 2009 and 2008. See Note 3 for further discussion of our Conectiv Acquisition.

	Year Ended December 31, 2010					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$ 2,525	$ 2,162	$ 978	$ 880	$ —	$ 6,545
Intersegment revenues	12	22	6	138	(178)	—
Total operating revenues	$ 2,537	$ 2,184	$ 984	$ 1,018	$ (178)	$ 6,545
Commodity Margin	$ 1,080	$ 504	$ 535	$ 272	$ —	$ 2,391
Add: Mark-to-market commodity activity, net and other revenue(1)	69	89	21	22	(30)	171
Plant operating expense	351	285	138	123	(29)	868
Depreciation and amortization expense	207	150	111	109	(7)	570
Sales, general and other administrative expense	55	38	45	12	1	151
Other operating expense(2)	59	2	28	4	(2)	91
Impairment losses	97	—	—	19	—	116
(Gain) on sale of assets, net	—	(119)	—	—	—	(119)
(Income) from unconsolidated investments in power plants	—	—	(16)	—	—	(16)
Income from operations	380	237	250	27	7	901
Interest expense, net of interest income						778
(Gain) loss on interest rate derivatives, net						247
Debt extinguishment costs and other (income) expense, net						106
Loss before income taxes and discontinued operations						$ (230)

	Year Ended December 31, 2009					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$ 3,311	$ 1,816	$ 558	$ 778	$ —	$ 6,463
Intersegment revenues	28	63	16	97	(204)	—
Total operating revenues	$ 3,339	$ 1,879	$ 574	$ 875	$ (204)	$ 6,463
Commodity Margin	$ 1,245	$ 644	$ 268	$ 304	$ —	$ 2,461
Add: Mark-to-market commodity activity, net and other revenue(1)	143	(40)	46	(5)	(44)	100
Plant operating expense	408	232	91	134	3	868
Depreciation and amortization expense	188	129	67	80	(8)	456
Sales, general and other administrative expense	66	63	18	27	—	174
Other operating expense(2)	73	14	30	11	(32)	96
Impairment losses	4	—	—	—	—	4
(Income) from unconsolidated investments in power plants	(32)	—	(18)	—	—	(50)
Income from operations	681	166	126	47	(7)	1,013
Interest expense, net of interest income						799
Debt extinguishment costs and other (income) expense, net						90
Income before reorganization items, income taxes and discontinued operations						124
Reorganization items						(1)
Income before income taxes and discontinued operations						$ 125

	Year Ended December 31, 2008					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$ 4,143	$ 3,806	$ 643	$ 1,245	$ —	$ 9,837
Intersegment revenues	49	252	25	229	(555)	—
Total operating revenues	$ 4,192	$ 4,058	$ 668	$ 1,474	$ (555)	$ 9,837
Commodity Margin	$ 1,155	$ 726	$ 279	$ 264	$ —	$ 2,424
Add: Mark-to-market commodity activity, net and other revenue(1)	(31)	195	(40)	36	(28)	132
Plant operating expense	406	267	108	128	(19)	890
Depreciation and amortization expense	177	130	57	70	(6)	428
Sales, general and other administrative expense	74	83	17	29	—	203
Other operating expenses(2)	78	14	27	28	(21)	126
Impairment losses	13	—	—	33	—	46
(Income) loss from unconsolidated investments in power plants	56	—	(7)	180	—	229
Income (loss) from operations	320	427	37	(168)	18	634
Interest expense, net of interest income						998
Debt extinguishment costs and other (income) expense, net						21
Loss before reorganization items, income taxes and discontinued operations						(385)
Reorganization items						(302)
Loss before income taxes and discontinued operations						$ (83)

(1) Mark-to-market commodity activity represents the unrealized portion of our mark-to-market activity, net, for the years ended December 31, 2010, 2009 and 2008, as well as a non-cash gain from amortization of prepaid power sales agreements for the year ended December 31, 2008 included in operating revenues and fuel and purchased energy expense on our Consolidated Statements of Operations.

(2) Excludes $9 million, $5 million and nil of RGGI compliance and other environmental costs for the years ended December 31, 2010, 2009 and 2008, respectively, which were included as a component of Commodity Margin.

Significant Customer

We did not have a customer that accounted for more than 10% of our annual consolidated revenues for the years ended December 31, 2010, 2009 or 2008.

17. Quarterly Consolidated Financial Data (unaudited)

Our quarterly operating results have been recast to present our results from Blue Spruce and Rocky Mountain as discontinued operations. 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, but not limited to, our restructuring activities (including asset sales), the completion of development projects, the timing and amount of curtailment of operations under the terms of certain PPAs, the degree of risk management and marketing, hedging and optimization activities, energy commodity market prices and variations in levels of production. Furthermore, the majority of the dollar value of capacity payments under certain of our PPAs are received during the months of May through October.

	Quarter Ended			
	December 31	September 30	June 30	March 31
	(in millions, except per share amounts)			
2010				
Operating revenues	$ 1,471	$ 2,130	$ 1,430	$ 1,514
Income from operations	89	554	108	150
Income (loss) before discontinued operations attributable to Calpine	$ (186)	$ 198	$ (119)	$ (55)
Discontinued operations, net of tax expense, attributable to Calpine	162	19	4	8
Net income (loss) attributable to Calpine	$ (24)	$ 217	$ (115)	$ (47)
Basic earnings (loss) per common share:				
Income (loss) before discontinued operations attributable to Calpine	$ (0.38)	$ 0.41	$ (0.25)	$ (0.11)
Discontinued operations, net of tax expense, attributable to Calpine	0.33	0.04	0.01	0.01
Net income (loss) attributable to Calpine	$ (0.05)	$ 0.45	$ (0.24)	$ (0.10)
Diluted earnings (loss) per common share:				
Income (loss) before discontinued operations attributable to Calpine	$ (0.38)	$ 0.41	$ (0.25)	$ (0.11)
Discontinued operations, net of tax expense, attributable to Calpine	0.33	0.04	0.01	0.01
Net income (loss) attributable to Calpine	$ (0.05)	$ 0.45	$ (0.24)	$ (0.10)
2009				
Operating revenues	$ 1,544	$ 1,822	$ 1,445	$ 1,652
Income from operations	197	423	159	234
Income (loss) before discontinued operations attributable to Calpine	$ (44)	$ 227	$ (89)	$ 20
Discontinued operations, net of tax expense, attributable to Calpine	1	11	11	12
Net income (loss) attributable to Calpine	$ (43)	$ 238	$ (78)	$ 32
Basic earnings (loss) per common share:				
Income (loss) before discontinued operations attributable to Calpine	$ (0.09)	$ 0.47	$ (0.18)	$ 0.04
Discontinued operations, net of tax expense, attributable to Calpine	0.00	0.02	0.02	0.03
Net income (loss) attributable to Calpine	$ (0.09)	$ 0.49	$ (0.16)	$ 0.07
Diluted earnings (loss) per common share:				
Income (loss) before discontinued operations attributable to Calpine	$ (0.09)	$ 0.47	$ (0.18)	$ 0.04
Discontinued operations, net of tax expense, attributable to Calpine	0.00	0.02	0.02	0.03
Net income (loss) attributable to Calpine	$ (0.09)	$ 0.49	$ (0.16)	$ 0.07

18. Our Emergence from Chapter 11

We emerged from Chapter 11 on January 31, 2008. From December 20, 2005 through the January 31 2008, we operated as a debtor-in-possession under the protection of the U.S. Bankruptcy Court following filings by Calpine Corporation and 274 of its wholly owned U.S. subsidiaries of voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. In addition, during that period, 12 of our Canadian subsidiaries that had filed for creditor protection under the CCAA also operated as debtors-in-possession under the jurisdiction of the Canadian Court. On February 8, 2008, the Canadian Court ordered and declared that the Canadian Debtors had completed all distributions previously ordered in full satisfaction of the pre-filing claims against them; the Canadian Debtors had otherwise fully complied with all orders of the Canadian Court; and the proceedings under the CCAA were terminated, including the stay of proceedings. We did not meet the requirements under U.S. GAAP to adopt fresh start accounting upon emergence.

Our Plan of Reorganization and Settlement of Claims — On January 31, 2008, we closed on our approximately $7.3 billion of First Lien Facilities and borrowed approximately $6.4 billion, which was used to repay the outstanding term loan balance of $3.9 billion (excluding the unused portion under the $1.0 billion revolver) under our DIP Facility, and were converted into exit financing under our First Lien Credit Facility. The remaining borrowed proceeds of approximately $2.5 billion, together with cash on hand, were used to distribute approximately $4.1 billion in cash for the cash payment obligations under our Plan of Reorganization and for working capital and general corporate purposes. See Note 6 for further discussion of our First Lien Credit Facility. Additionally, we authorized issuance of 485 million shares of reorganized Calpine Corporation common stock primarily for the discharge of liabilities subject to compromise, repayment of the Second Priority Debt and for various other administrative and other post-petition claims. Through the filing of this report, approximately 441 million shares have been distributed to holders of allowed unsecured claims and approximately 44 million shares remain in reserve for distribution to holders of disputed claims whose claims ultimately become allowed. As disputed claims are resolved, the claimants receive distributions of shares from the reserve on the same basis as if such distributions had been made on or about the Effective Date. Any reserved shares that remain undistributed upon resolution of the remaining disputed claims will not be returned to us but rather will be distributed pro rata to claimants with allowed claims to increase their recovery. Holders of allowed interests in Calpine Corporation (primarily holders of Calpine Corporation common stock existing as of the Petition Date) received a pro rata share of warrants to purchase approximately 48.5 million shares of reorganized Calpine Corporation common stock at $23.88 per share. Warrants for 21,499 shares of common stock were exercised prior to expiration. The remaining unexercised warrants expired on August 25, 2008. Proceeds received of approximately $1 million from the exercise of the warrants were recorded as additional paid-in capital.

Interest Expense — We recorded $135 million in post-petition interest from January 1, 2008, through the Effective Date. This amount represents non-cash value to be satisfied through distributions of shares of Calpine Corporation's reorganized common stock.

Reorganization Items — Reorganization items represent the direct and incremental costs related to our Chapter 11 cases. Our historical financial performance during the pendency of our Chapter 11 cases and CCAA proceedings is likely not indicative of our future financial performance. While we may continue to pay professional and trustee fees related to our Chapter 11 cases until the claims resolution process is completed and our Chapter 11 case is formally dismissed by the U.S. Bankruptcy Court, we do not expect such fees to be material. We did not report such fees as reorganization items on our Consolidated Statement of Operations in 2010 and our reorganization items in 2009 were not significant. During the year ended December 31, 2008, we recorded reorganization items of $(302) million, which primarily related to the following:

- Gains for the settlement of expected allowed claims of $95 million, most of which related to the settlement of claims with the Canadian Debtors and other deconsolidated foreign entities of $62 million, a $12 million credit related to our settlement with Rosetta and a $34 million credit for RockGen.

- Gains of \$206 million, primarily on the sales of the Hillabee and Fremont development project assets, which were part of our Plan of Reorganization. See Note 3 for further discussion of our sales of Hillabee and Fremont.

- A gain on the reconsolidation of the Canadian Debtors of \$71 million.

- Partially offset by professional and trustee fees of \$85 million and other miscellaneous items.

CALPINE CORPORATION AND SUBSIDIARIES

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Year	Charged to Expense	Reductions[1]	Other[2]	Balance at End of Year
			(in millions)		
Year ended December 31, 2010					
Allowance for doubtful accounts	$ 14	$ (12)	$ —	$ —	$ 2
Deferred tax asset valuation allowance	2,572	(186)	—	—	2,386
Year ended December 31, 2009					
Allowance for doubtful accounts	$ 42	$ 2	$(30)	$ —	$ 14
Deferred tax asset valuation allowance	2,685	(113)	—	—	2,572
Year ended December 31, 2008					
Allowance for doubtful accounts	$ 54	$ 15	$(27)	$ —	$ 42
Allowance for doubtful accounts with related party Canadian Debtors and other deconsolidated foreign entities	10	—	(10)	—	—
Reserve for notes receivable	39	—	(39)	—	—
Reserve for interest and notes receivable with related party Canadian Debtors and other deconsolidated foreign entities	83	—	(83)	—	—
Deferred tax asset valuation allowance	2,401	(194)	—	478	2,685

(1) Represents write-offs of accounts considered to be uncollectible and previously reserved.

(2) The adjustment of $478 million represents the additions resulting from our reconsolidation of our Canadian Debtors and other deconsolidated foreign entities and the difference in the amounts disclosed in our prior 10-K and the final amount as filed in our 2007 tax return. There was no impact to our Statement of Operations for the year ended December 31, 2008.

OTAY MESA ENERGY CENTER, LLC

INDEX TO FINANCIAL STATEMENTS
December 31, 2009

OMEC met the criteria to require us to present separate, standalone financial statements in this Report based upon the relationship of our equity income from our investment in OMEC to our consolidated net income before income taxes, as defined under SEC guidelines, for the year ended December 31, 2008. OMEC was consolidated effective January 1, 2010; however our separate, standalone financial statements of OMEC are included below for the years ended December 31, 2009 and 2008, during which, we accounted for OMEC under the equity method of accounting.

Report of Independent Registered Public Accounting Firm

To the Member of
Otay Mesa Energy Center, LLC

In our opinion, the accompanying balance sheets and the related statements of operations, comprehensive income (loss) and member's interest, and cash flows present fairly, in all material respects, the financial position of Otay Mesa Energy Center, LLC at December 31, 2009 and 2008, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. 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 of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 24, 2010

OTAY MESA ENERGY CENTER, LLC
(Previously a Development Stage Company)

BALANCE SHEETS
December 31, 2009 and 2008
(in thousands)

	2009	2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,509	$ 11,486
Restricted cash	7,672	70
Accounts receivable, related party	10,578	—
Deferred income taxes, current	387	513
Materials and supplies	1,410	—
Prepaid expenses and other current assets	235	433
Deferred transmission credits, related party	—	22,661
Total current assets	27,791	35,163
Property, plant and equipment, net	542,002	462,713
Intangible assets, net	43,430	46,119
Deferred financing costs, net	7,047	7,776
Deferred lease levelization receivable	2,047	—
Total assets	$ 622,317	$ 551,771
LIABILITIES & MEMBER'S INTEREST		
Current liabilities:		
Accounts payable, trade	$ 1,975	$ 28,716
Accounts payable, related party	4,479	4,733
Derivative liabilities, current	16,744	12,322
Project financing, current	9,949	2,487
Accrued interest payable	4,314	951
Other current liabilities	82	1,759
Income tax payable, related party	28	28
Total current liabilities	37,571	50,996
Project financing, net of current portion	364,564	253,870
Written call option	46,119	46,119
Long-term derivative liabilities	25,893	72,251
Deferred income taxes, net of current portion	387	513
Asset retirement obligations	786	612
Other long-term liabilities	998	627
Total liabilities	476,318	424,988
Commitments and contingencies (see Note 11)		
Member's interest	145,999	126,783
Total liabilities and member's interest	$ 622,317	$ 551,771

The accompanying notes are an integral part of these Financial Statements.

OTAY MESA ENERGY CENTER, LLC
(Previously a Development Stage Company)

STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2009 and 2008
(in thousands)

	2009	2008
Operating revenues	$ 20,398	$ —
Cost of revenue:		
Plant operating expense, related party	2,454	—
Plant operating expense	387	—
Depreciation and amortization expense	5,097	—
Project development expense	2,949	507
Sales, general and other administrative expense	3,674	436
Asset impairment expense	1,647	—
Accretion of asset retirement obligations	72	53
Total cost of revenue	16,280	996
Income (loss) from operations	4,118	(996)
Interest expense	(23,120)	52,934
Interest (income)	(658)	(1,706)
Liquidating damages	6,050	—
Other expense	195	—
Income (loss) before income taxes	21,651	(52,224)
Income tax expense	—	28
Net income (loss)	$ 21,651	$(52,252)

The accompanying notes are an integral part of these Financial Statements.

OTAY MESA ENERGY CENTER, LLC
(Previously a Development Stage Company)

STATEMENTS OF COMPREHENSIVE INCOME (LOSS) AND MEMBER'S INTEREST
For the Years Ended December 31, 2009 and 2008
(in thousands)

	Member's Interest	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Member's Interest	Comprehensive Income (Loss)
Balance, December 31, 2007	$203,691	$ (8,284)	$ (9,696)	$185,711	
Contributions from member	10,336	—	—	10,336	
Comprehensive loss from interest rate swaps	—	—	(17,012)	(17,012)	$(17,012)
Net loss	—	(52,252)	—	(52,252)	(52,252)
Total comprehensive loss					$(69,264)
Balance, December 31, 2008	214,027	(60,536)	(26,708)	126,783	
Contributions from member	4,250	—	—	4,250	
Distributions to member	(9,130)	—	—	(9,130)	
Comprehensive gain from interest rate swaps	—	—	334	334	$ 334
Reclassification adjustment for losses included in net income	—	—	2,111	2,111	2,111
Net income	—	21,651	—	21,651	21,651
Total comprehensive income					$ 24,096
Balance, December 31, 2009	$209,147	$(38,885)	$(24,263)	$145,999	

The accompanying notes are an integral part of these Financial Statements.

OTAY MESA ENERGY CENTER, LLC
(Previously a Development Stage Company)

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2009 and 2008
(in thousands)

	2009	2008
Cash flows from operating activities:		
Net income (loss)	$ 21,651	$ (52,252)
Adjustments to reconcile net income (loss) to net cash used in operating activities:		
Depreciation expense	4,055	—
Amortization of intangible assets	1,042	—
Asset impairment expense	1,647	—
Amortization of deferred financing costs	226	—
Accretion of asset retirement obligations	72	53
Unrealized mark-to-market activities, net	(39,492)	49,644
Lease levelization expense (revenue), net	(1,676)	—
Change in deferred transmission expense	—	(1,630)
Change in operating assets and liabilities:		
Prepaid expense and other current assets	(235)	—
Accounts receivable, related party	(10,578)	—
Deferred transmission credits, related party	3,795	—
Accounts payable, related party	3,572	—
Materials and supplies	(1,410)	—
Accrued interest payable	3,439	518
Other current liabilities	(5)	—
Accounts payable, trade	884	18
Income tax payable, related party	—	28
Net cash used in operating activities	(13,013)	(3,621)
Cash flows from investing activities:		
Purchases of property, plant and equipment	(115,127)	(179,594)
Increase in restricted cash	(7,602)	(70)
Transmission credit proceeds	19,045	—
Transmission credit expenditures, related party	(226)	(9,313)
Net cash used in investing activities	(103,910)	(188,977)
Cash flows from financing activities:		
Borrowings under project financing	120,643	193,157
Repayment of project financing	(2,487)	—
Distributions to member	(9,130)	—
Contributions from member	4,250	10,336
Deferred financing costs	(330)	(495)
Net cash provided by financing activities	112,946	202,998
Net (decrease) increase in cash and cash equivalents	(3,977)	10,400
Cash and cash equivalents, beginning of period	11,486	1,086
Cash and cash equivalents, end of period	$ 7,509	$ 11,486
Cash paid during the period for:		
Interest, net of amounts capitalized	$ 12,727	$ 2,771
Income taxes	$ —	$ —
Supplemental disclosure of non-cash investing activities:		
Change in property, plant and equipment financed by accounts payable and other liabilities	$ (33,097)	$ 15,376
Amortization of deferred financing costs capitalized to property, plant and equipment	$ 524	$ 381
Additions to property, plant and equipment	$ 790	$ 1,848

The accompanying notes are an integral part of these Financial Statements.

OTAY MESA ENERGY CENTER, LLC
(Previously a Development Stage Company)

NOTES TO FINANCIAL STATEMENTS
For the Years Ended December 31, 2009 and 2008

1. Organization and Operations

Otay Mesa Energy Center, LLC (previously a development stage company), a Delaware limited liability company, is an indirect, wholly owned subsidiary of Calpine Corporation ("Calpine Corp."). OMEC was formed for the purpose of developing, constructing, financing, operating and maintaining Otay Mesa Energy Center, a 608 MW peak capacity, natural gas-fired, combined-cycle power plant (the "Plant") located in San Diego County, California. The Plant commenced operations on October 3, 2009 (the "Commercial Operations Date"). The Plant sells capacity under a long-term PPA with a related party, SDG&E. See Note 8 for additional discussion.

Management believes the Plant meets the current requirements for status as an EWG, as defined by PUHCA 2005. An EWG is defined as the owner or operator of an electric generation plant used exclusively for the wholesale generation and sale of electric power.

Prior to 2007, all activities related to the development and construction of the Plant were conducted by Calpine Corp. and certain of its affiliates. Effective May 1, 2007, OMEC entered into various agreements, including the PPA Reinstatement Agreement, the Contribution and Transfer Agreement and the Ground Sublease and Easement Agreement (collectively, the "Agreements"), by and among OMEC, Calpine Corp. and SDG&E. In accordance with the Agreements, Calpine Corp. and certain of its affiliates contributed all cash, property and equipment, and other assets and liabilities associated with the Plant to OMEC and assigned certain related contracts to OMEC.

Calpine assigned its leasehold interest under the Ground Sublease and Easement Agreement (the "Sublease Agreement") to SDG&E. The Sublease Agreement includes a put option by OMEC to sell, and a call option by SDG&E to buy, the Plant at the end of the term of the PPA. See Note 3 for additional discussion. Management of Calpine Corp. determined that the PPA, along with the put and call options, absorb the majority of the risk from OMEC such that OMEC is a VIE and Calpine Corp. is not the primary beneficiary during the period May 1, 2007 to December 31, 2009. As there was a new primary beneficiary as of May 1, 2007, there was a change in the basis of accounting. As a result, the assets and liabilities contributed by Calpine Corp. and certain of its affiliates were measured at fair value as of May 1, 2007, (the "Contribution Date"). Prior to the Commercial Operations Date, OMEC devoted substantially all its efforts to constructing the Plant.

2. Business Risks

Several current issues in the power industry could have an effect on OMEC's financial performance. Some of the business risks and uncertainties that could cause future results to differ from historical results include, but are not limited to:

- The uncertain length and severity of the current depressed general financial and economic conditions and its impacts on OMEC's business, including demand for power and the ability of OMEC's contractual counterparties to perform under their contracts with OMEC;

- OMEC's ability to manage its customer and counterparty exposure and credit risk;

- Regulation in the markets in which OMEC participates and OMEC's ability to effectively respond to changes in federal, state and regional laws and regulations, including environmental regulations;

- Natural disasters such as hurricanes, earthquakes and floods, or acts of terrorism that may impact the Plant or the market it serves;

- Seasonal fluctuations of OMEC's results and exposure to variations in weather patterns;

- Disruptions in or limitations on the transportation of natural gas and transmission of power;

- Present and possible future claims, litigation and enforcement actions;

- Risks associated with the operation of a power plant including unscheduled outages; and

- The expiration or termination of OMEC's PPA with SDG&E and the related results on revenues.

3. Summary of Significant Accounting Policies

Basis of Presentation

The financial statements have been prepared in accordance with U.S. GAAP. The financial statements reflect all costs of doing business, including those incurred by Calpine Corp. on OMEC's behalf. Costs that are clearly identifiable as being applicable to OMEC have been allocated to OMEC by Calpine Corp. Centralized departments that serve all business units have allocated costs to OMEC using relevant allocation measures, primarily budgeted productivity. The most significant costs in this category include salaries and benefits of certain employees, legal and other professional fees, information technology costs and facilities costs, including office rent. Calpine Corp. corporate costs that clearly relate to other business segments of Calpine Corp. have not been allocated to OMEC.

Use of Estimates in Preparation of Financial Statements

The preparation of the financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosure in these financial statements. Actual results could differ from those estimates.

Fair Value of Financial Instruments

The carrying value of cash and cash equivalents, restricted cash, accounts receivable, accounts payable and other current liabilities approximate their respective fair values due to their short-term maturities. See Note 5 for disclosures regarding the fair value of OMEC's project financing. See Note 6 for disclosures regarding the fair value of OMEC's derivative instruments.

Concentration of Credit Risk

Financial instruments that potentially subject OMEC to credit risk consist primarily of cash and cash equivalents, restricted cash, accounts receivable and derivative instruments. Cash and cash equivalent balances, as well as restricted cash balances, may exceed FDIC limits or are invested in money market accounts with investment banks that are not FDIC insured. OMEC places cash and cash equivalents and restricted cash in what it believes to be credit-worthy financial institutions, and certain money market accounts invest in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. Government, its agencies or instrumentalities. The counterparty to the interest rate swaps is a major financial institution. Management does not believe there is significant risk to OMEC relating to the financial institutions. OMEC sells power to a public utility under a long-term agreement, and accounts receivable are concentrated with SDG&E. OMEC has exposure to trends within the energy industry, including declines in the creditworthiness of SDG&E. OMEC generally has not collected collateral or other security to support its power-related accounts receivable. OMEC does not believe there is significant credit risk associated with SDG&E.

Cash and Cash Equivalents

OMEC considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash

OMEC is required to maintain cash balances that are restricted by the provisions of its financing agreement, which restricts the use of certain cash inflows received during the construction phase and after achieving commercial operations. These amounts are held by a depository bank in order to comply with the contractual provisions regarding reserves for operating, maintenance, debt service, and restricted distributions to OMEC's parent. Funds that can be used to satisfy obligations due during the next 12 months are classified as current restricted cash. Restricted cash is generally invested in accounts earning market rates; therefore, the carrying value approximates fair value. Such cash is excluded from cash and cash equivalents in the Balance Sheets and Statements of Cash Flows.

Accounts Receivable and Payable

Accounts receivable and payable represent amounts due from customers, including related parties, and owed to both related party and third-party vendors. Accounts receivable are recorded at invoiced amounts, net of reserves and allowances, and do not bear interest. Receivable balances greater than 30 days past due are individually reviewed for collectability, and if deemed uncollectible, are charged off against the allowance accounts after all means of collection have been exhausted and the potential for recovery is considered remote. Management uses their best estimate to determine the required allowance for doubtful accounts based on a variety of factors, including the length of time receivables are past due, economic trends and significant one-time events. Specific provisions are recorded for individual receivables when management becomes aware of a customer's inability to meet its financial obligations. Management reviews the adequacy of the reserves and allowances quarterly. As of December 31, 2009 and 2008, OMEC determined that no allowance for doubtful accounts was required.

Capitalized Interest

OMEC capitalized interest on capital invested in the Plant during the advanced stages of development and the construction period. OMEC's qualifying assets included all of its construction in progress. Interest capitalized totaled $5.8 million and $9.2 million for the years ended December 31, 2009 and 2008, respectively. Upon commencement of commercial operations of the Plant, capitalized interest, as a component of the total cost of the Plant, is amortized over the estimated useful life of the Plant.

Derivative Instruments

OMEC entered into derivative instruments to manage its interest rate risk on its project financing. OMEC recognizes all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measures those instruments at fair value. OMEC presents cash flows from interest rate swaps within operating activities on the Statements of Cash Flows.

Gains and losses on interest rate swaps that qualify for hedge accounting are recorded in the period and same financial statement line item as the hedged item. Hedge accounting requires management to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. For gains and losses on interest rate swaps that do not qualify for or have not been documented for hedge accounting treatment, changes in fair value are recognized currently into earnings.

Accounting for derivatives at fair value requires management to make estimates about future prices during periods for which price quotes are not available from external sources, in which case management relies on internally developed price estimates. During periods where external price quotes are not available, management derives such future price estimates based on an extrapolation of prices from periods where external price quotes are available. Management performs this extrapolation using liquid and observable market prices and extending those prices to an internally generated long-term price forecast based on a generalized equilibrium model.

Materials and Supplies

Materials and supplies consist of spare parts and are valued at weighted average cost. Costs are expensed to plant operating expense or capitalized to property, plant and equipment as the parts are utilized and consumed.

Property, Plant and Equipment, Net

Property, plant, and equipment items are recorded at cost. OMEC capitalizes costs incurred in connection with the construction of the Plant and the refurbishment of major turbine generator equipment. Annual planned maintenance is expensed when the service is performed. The Plant's assets, excluding rotable parts, are depreciated on a composite basis over a useful life of 37 years, utilizing the straight-line method and an estimated salvage value of 10% of the depreciable cost basis. Rotable parts are depreciated on a component basis, which generally ranges from 3 to 18 years, utilizing the straight-line method, with an estimated salvage value of 0.15% of the depreciable cost basis.

Impairment Evaluation of Long-Lived Assets

Management evaluates long-lived assets for impairment when such events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. When management believes an impairment condition may have occurred, they are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities for long-lived assets that are expected to be held and used. Such cash flows do not include interest or tax expense cash outflows. 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. Except as noted below at *Intangible Assets, Net,* no impairment charge was recorded for the years ended December 31, 2009 and 2008.

Intangible Assets, Net

Intangible assets consist of contractual rights and the put option included within the Agreements that were recorded at fair value on the Contribution Date, when Calpine Corp. contributed assets and liabilities to OMEC. Intangible assets with finite lives are amortized on a straight-line basis over their estimated useful lives and are reviewed for impairment whenever changes in circumstances indicate that the carrying amount of the asset may not be recoverable. Contractual rights under the Agreements totaled $42.6 million and began amortizing on the Commercial Operations Date. The contractual rights are subject to amortization over the ten-year term of the PPA on a straight-line basis. Amortization expense on the contractual rights totaled $1.0 million for the year ended December 31, 2009, and is included in depreciation and amortization expense in the Statement of Operations. The put option included within the Agreements is generally exercisable 180 days after the ninth anniversary of the commercial operation date through the tenth anniversary and allows OMEC to put the Plant to SDG&E for $280.0 million. The put had a value of $3.5 million at inception and is reviewed at least annually for impairment. During 2009, management determined that the put option was impaired based on an evaluation of the likelihood that the option will be exercised. As a result of this evaluation, management recorded asset impairment expense of $1.6 million in the Statement of Operations for the year ended December 31, 2009. No impairment expense was recorded for the year ended December 31, 2008.

The Agreements also include a call option whereby SDG&E may purchase the Plant for $377.0 million. The call option is valued at $46.1 million and is generally exercisable between the ninth and tenth anniversaries of the Plant's Commercial Operations Date. The carrying value of the call will be adjusted at the time the option is exercised or expires.

Asset Retirement Obligations

OMEC records all known asset retirement obligations for which the liability's fair value can be reasonably estimated. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. OMEC's asset retirement obligations primarily relate to land leases upon which the Plant is built.

Deferred Financing Costs, Net

Costs incurred related to the issuance of debt instruments are deferred and amortized over the term of the related debt using the effective interest rate method. Prior to the Commercial Operations Date, amortization costs of $0.5 million and $0.4 million for the years ended December 31, 2009 and 2008, respectively, were capitalized to construction in progress and are subject to amortization over the estimated useful life of the Plant. Subsequent to the Commercial Operations Date, amortization costs of $0.2 million were included in interest expense in the Statement of Operations for the year ended December 31, 2009.

Revenue Recognition

Contracts accounted for as operating leases, such as certain tolling agreements, with minimum lease rentals that vary over time must be levelized. The PPA with SDG&E is a tolling agreement that meets the criteria of an operating lease. OMEC levelizes the minimum lease payments on a straight-line basis over the term of the contract.

Project Development Expense

Project development expense represents costs incurred by OMEC prior to the Commercial Operations Date related to anticipated post-operational needs of the Plant. Such costs included hiring and training of operations personnel, which are not subject to capitalization under U.S. GAAP and were expensed as incurred.

Income Taxes

OMEC is a single member limited liability company whose tax results are included in the consolidated U.S. federal and state income tax returns of Calpine Corp. and is treated as a taxable entity for financial reporting purposes. For separate company financial reporting purposes, income taxes are calculated by OMEC on a separate return basis.

Income taxes are accounted for under the asset and liability method. OMEC has reported its assets and liabilities at fair value as of the Contribution Date; however, the deferred tax assets and liabilities are recorded based on Calpine Corp.'s original basis as there was no change in the tax entity. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying values of existing assets and liabilities and their respective tax bases and net operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities due to a change in tax rates is recognized in income in the period that includes the enactment date. OMEC recognizes interest and penalties incurred in income tax expense in the statements of operations. For the years ended December 31, 2009 and 2008, OMEC did not incur any tax-related penalties or interest.

OMEC recognizes the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination. A tax position that meets the more-likely-than-not recognition threshold is measured as the largest amount of tax benefit that is greater than 50%

likely of being realized upon ultimate settlement with a taxing authority. OMEC reverses a previously recognized tax position in the first period in which it is no longer more likely than not that the tax position would be sustained upon examination. See Note 9 for further discussion on OMEC's income taxes.

New Accounting Standards and Disclosure Requirements

Accounting Standards Codification and GAAP Hierarchy — Effective for interim and annual periods ending after September 15, 2009, the Accounting Standards Codification, or ASC, and related disclosure requirements issued by the Financial Accounting Standards Board became the single official source of authoritative, nongovernmental GAAP. The ASC simplifies GAAP, without change, by consolidating the numerous, predecessor accounting standards and requirements into logically organized topics. All other literature not included in the ASC is non-authoritative. Management adopted the ASC as of September 30, 2009, which did not have any impact on the results of operations, financial condition or cash flows as it does not represent new accounting literature or requirements; however, it did change references within this report to authoritative sources of GAAP to the new ASC nomenclature.

Fair Value Measurements of Non- Financial Assets and Non-Financial Liabilities — Effective for interim and annual periods beginning after November 15, 2008, GAAP includes new standards related to fair value measurements for non-financial assets and liabilities. These new standards do not apply to assets and liabilities that were not previously required to be recorded at fair value, but do apply when other accounting standards require fair value measurements. The new standards also define fair value, establish a framework for measuring fair value under GAAP and enhance disclosures about fair value measurements. Management adopted the new standards with respect to non-financial assets and non-financial liabilities as of January 1, 2009, which did not have a material effect on the results of operations, financial position or cash flows; however, adoption may impact measurements of asset impairments and asset retirement obligations if they occur in the future.

Disclosures About Derivative Instruments and Hedging Activities — Effective for interim and annual periods beginning after November 15, 2008, GAAP includes enhanced disclosure requirements relating to an entity's derivative and hedging activities to enable investors to better understand their effects on the entity's financial position, financial performance, and cash flows. OMEC adopted the new disclosure requirements as of January 1, 2009. Adoption resulted in additional disclosures related to OMEC's derivatives and hedging activities including additional disclosures regarding OMEC's objectives for entering into derivative transactions, increased balance sheet and financial performance disclosures, volume information and credit enhancement disclosures. See Note 7 for OMEC's derivative disclosures.

Fair Value Measurements and Disclosures — In January 2010, FASB issued Accounting Standards Update 2010-06, "Fair Value Measurements and Disclosures" to enhance disclosure requirements relating to different levels of assets and liabilities measured at fair value and to clarify certain existing disclosures. The update requires disclosure of transfers in and out of levels 1 and 2 and gross presentation of purchases, sales, issuances and settlements in the level 3 reconciliation of beginning and ending balances. The new disclosure requirements relating to level 3 activity are effective for interim and annual periods beginning after December 15, 2010 and all the other requirements are effective for interim and annual periods beginning after December 15, 2009. Since this update only requires additional disclosures, management does not expect this standard to have a material impact on OMEC's results of operations, cash flows or financial position.

Subsequent Events — Effective for interim and annual periods ending after June 15, 2009, GAAP includes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The new standards do not change the accounting for subsequent events; however, they do require disclosure, on a prospective basis, of the date an entity has evaluated subsequent events. Management adopted these new standards for the year ended December 31, 2009, which had no impact on OMEC's results of operations, financial condition or cash flows. Management has evaluated subsequent events up to the time of issuance of this Report on February 24, 2010.

4. Property, Plant and Equipment, Net

As of December 31, 2009 and 2008, property, plant and equipment, are stated at cost less accumulated depreciation as follows (in thousands):

	2009	2008
Building, machinery and equipment	$ 529,364	$ —
Construction in progress	—	446,020
Emission reduction credits	16,693	16,693
	546,057	462,713
Less: Accumulated depreciation	4,055	—
Property, plant and equipment, net	$ 542,002	$ 462,713

5. Project Financing

On the Contribution Date, OMEC entered into a credit agreement with a group of lenders for $377.0 million (the "Credit Agreement"). The project financing is collateralized by OMEC's assets and is non-recourse to Calpine Corp. and its other affiliates. The project financing was used to fund the construction activities for the Plant. The construction loan converted to a term loan on November 13, 2009, after the Plant satisfied conversion requirements of the Credit Agreement. The term loan matures on April 30, 2019.

Borrowings under the Credit Agreement bear variable interest that, depending on the specific terms of the loan, are calculated based on adjusted LIBOR plus an applicable margin of 1.5%. The effective interest rate was approximately 7.1% for both the years ended December 31, 2009 and 2008. The Credit Agreement requires OMEC to maintain certain covenants, including debt service coverage and debt to equity ratios, once the Plant commenced commercial operations, as well as certain other funding and performance covenants.

As of December 31, 2009, the scheduled maturities of the project financing are as follows (in thousands):

2010	$ 9,949
2011	9,949
2012	9,949
2013	9,949
2014	9,949
Thereafter	324,768
Total	$ 374,513

Under GAAP, OMEC measures the fair value of its project financing using discounted cash flow analyses based on current borrowing rates for similar types of borrowing arrangements. The estimated fair value of the project financing was $339.4 million and $227.0 million as of December 31, 2009 and 2008, respectively, with the increase in fair value primarily due to additional borrowings under the project financing in 2009.

6. Fair Value Measurements

Financial Instruments

OMEC has cash equivalents that are classified within level 1 of the fair value hierarchy as the amounts approximate fair value. These financial instruments are invested in money market accounts and included in cash and cash equivalents and restricted cash on the Balance Sheets.

Interest Rate Swaps

A significant portion of OMEC's debt is indexed to LIBOR. Management uses interest rate swaps to effectively convert a portion of the floating rate component of the debt to a fixed rate. These transactions act as economic hedges for the interest cash flow. Interest rate swaps are measured at their fair value and recorded as either assets or liabilities. OMEC does not use interest rate derivative instruments for trading purposes.

The fair value of OMEC's interest rate swaps is determined based on observable market-based pricing inputs, and the swaps are classified as level 2 derivative instruments. Generally, management obtains level 2 pricing inputs from markets such as Bloomberg. In certain instances, level 2 derivative instruments may utilize models to measure fair value. These models are primarily industry-standard models that incorporate various assumptions, including quoted interest rates, correlation, volatility, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

OMEC utilizes market data, such as pricing services and broker quotes, and assumptions that management believes market participants would use in pricing assets or liabilities including assumptions about risks and the risks inherent to the inputs in the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The market data obtained from broker pricing services is evaluated to determine the nature of the quotes obtained and, where accepted as a reliable quote, used to validate management's assessment of fair value; however, other qualitative assessments are used to determine the level of activity in any given market. OMEC primarily applies the market approach and income approach for recurring fair value measurements and utilizes what management believes to be the best available information. The valuation techniques used seek to maximize the use of observable inputs and minimize the use of unobservable inputs. The fair value balances are classified based on the observability of those inputs.

The fair value of OMEC's derivatives includes consideration of OMEC's credit standing and the credit standing of its counterparties. OMEC has also recorded credit reserves in the determination of fair value based on management's expectation of how market participants would determine fair value. Such valuation adjustments are generally based on market evidence, if available, or management's best estimate.

The following tables present OMEC's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009 and 2008, by level within the fair value hierarchy. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	December 31, 2009			
	Level 1	Level 2	Level 3[(2)]	Total
	(in thousands)			
Assets:				
Cash equivalents[(1)]	$ 15,099	$ —	$—	$ 15,099
Total assets	$ 15,099	$ —	$—	$ 15,099
Liabilities:				
Interest rate swaps	$ —	$42,637	$—	$ 42,637
Total liabilities	$ —	$42,637	$—	$ 42,637

	December 31, 2008			
	Level 1	Level 2	Level 3[2]	Total
		(in thousands)		
Assets:				
Cash equivalents[1]	$ 11,556	$ —	$—	$ 11,556
Total assets	$ 11,556	$ —	$—	$ 11,556
Liabilities:				
Interest rate swaps	$ —	$84,573	$—	$ 84,573
Total liabilities	$ —	$84,573	$—	$ 84,573

(1) As of December 31, 2009, and 2008, cash equivalents of $7.4 million and $11.5 million were included in cash and cash equivalents, and $7.7 million and $0.1 million were included in restricted cash, respectively.

(2) There were no derivative assets (liabilities), net transferred out of Level 3 during 2009 and 2008.

7. Derivative Instruments

Accounting for Derivative Instruments

Cash Flow Hedges — OMEC reports the effective portion of the unrealized gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument as a component of OCI and reclassifies such gains and losses into earnings in the same period during which the hedged forecasted transaction affects earnings. Gains and losses due to ineffectiveness on commodity hedging instruments are included in unrealized gains and losses and are recognized currently in earnings as interest expense. If it is determined that the forecasted transaction is no longer probable of occurring, then hedge accounting will be discontinued prospectively. If the hedging instrument is terminated or de-designated prior to the occurrence of the hedged forecasted transaction, the gain or loss associated with the hedge instrument remains deferred in OCI until such time as the forecasted transaction impacts earnings, or until it is determined that the forecasted transaction is probable of not occurring.

Derivatives Not Designated as Hedging Instruments — OMEC enters into interest rate transactions that primarily act as economic hedges, but either do not qualify as hedges under hedge accounting guidelines or qualify under the hedge accounting guidelines and the hedge accounting designation has not been elected. Changes in fair value of derivatives not designated as hedging instruments are recognized currently in earnings as interest expense.

OMEC designated interest rate swap agreements as cash flow hedges of the project financing on October 31, 2007, and discontinued the cash flow hedge designation on March 31, 2008. During this period, changes in the fair value related to the effective portion of the swap agreements were recorded to AOCI. During the three months ended March 31, 2008, OMEC recognized an unrealized loss in AOCI totaling $17.0 million. Subsequent to March 31, 2008, changes in the fair value of the swap agreements were recorded in earnings as a component of interest expense.

As of December 31, 2009, the net forward notional buy (sell) position of OMEC's outstanding interest rate swap contracts were as follows (in thousands):

Derivative Instruments	Notional Volumes
Interest rate swaps	$ 374,513

Changes in the fair values of derivative instruments (both assets and liabilities) are reflected either in OCI, net of tax, for the effective portion of derivative instruments which qualify for cash flow hedge accounting treatment, or on the Statements of Operations as a component of interest expense within net income.

The following table details the components of total mark-to-market activity for both the net realized gain (loss) and the net unrealized gain (loss) recognized from OMEC's interest rate swaps included in interest expense in the Statements of Operations for the years ended December 31, 2009 and 2008 (in thousands):

	2009	2008
Realized gain (loss)	$ (14,652)	$ (3,631)
Unrealized gain (loss)	39,492	(49,644)
Total mark-to-market gain (loss)	$ 24,840	$ (53,275)

For the years ended December 31, 2009 and 2008, OMEC recorded losses to increase interest expense of $2.1 million and $0, respectively, based on the reclassification adjustment from AOCI into earnings. OMEC currently estimates that pre-tax losses of approximately $6.9 million would be reclassified from AOCI into earnings during the 12 months ended December 31, 2010.

8. Related Party Transactions

Project Management Agreement

On the Contribution Date, OMEC entered into an agreement (the "PMA") with Calpine Construction Management Company, Inc. ("CCMCI"), an indirect, wholly owned subsidiary of Calpine Corp., whereby CCMCI would provide all project management and procurement services, installation services, commissioning services and post completion services for the construction of the Plant. After completion of the performance conditions stipulated in the PMA, including payment of outstanding balances, the PMA will be terminated. Under the PMA, OMEC incurred costs of $19.7 million and $4.4 million for the years ended December 31, 2009 and 2008, respectively, which were capitalized to property, plant and equipment. Additionally, the PMA required CCMCI to pay delay liquidated damages to OMEC in the amount of $101,000 per day in the event that the project completion did not occur on or before the guaranteed completion date of May 1, 2009. Liquidating damages to OMEC under the PMA totaled $15.1 million and were recorded as a reduction in amounts capitalized to property, plant and equipment. As of December 31, 2009 and 2008, accounts payable to CCMCI totaled $0.3 million and $0.8 million, respectively.

Operations and Maintenance Agreement

OMEC has contracted with Calpine Operating Services Company, Inc. ("COSCI"), an indirect, wholly owned subsidiary of Calpine Corp. for the operation and maintenance of the Plant under an agreement (the "O&M Agreement") dated May 1, 2007. The O&M Agreement is effective through the maturity date of the project financing, with provisions for successive one-year renewals. Under the terms of the O&M Agreement, COSCI is obligated to perform all operation and maintenance services in connection with the business, including operation, repair and maintenance, administrative and billing services, technical analyses and contract administration. OMEC reimburses COSCI for its direct costs, including direct labor costs and other costs incurred in the performance of the services. The O&M Agreement stipulates a quarterly administrative fee of $125,000, which is subject to annual escalation. For the years ended December 31, 2009 and 2008, OMEC recorded expenses under the O&M Agreement of $2.5 million and $0, respectively, inclusive of reimbursable expenses. As of December 31, 2009 and 2008, accounts payable to COSCI totaled $0.9 million and $0, respectively.

Activity with Calpine Corp.

On the Contribution Date, Calpine Corp. contributed cash, property, plant and equipment, other assets and liabilities to OMEC under the Contribution and Transfer Agreement dated October 23, 2006. Calpine Corp. contributed its benefit to payments under a note receivable in the amount of $1.7 million for the year ended

December 31, 2008. In addition to the payment due under the note receivable, Calpine Corp. contributed $4.3 million and $8.6 million of cash to OMEC for the years ended December 31, 2009 and 2008, respectively, to support construction-related activities.

During 2009, OMEC made a cash distribution to Calpine Corp. for $9.1 million in accordance with the terms of the Credit Agreement. OMEC also recorded cost allocations from Calpine Corp. for centralized services for $2.3 million, which are included in general and administrative expense in the Statement of Operations for the year ended December 31, 2009.

At December 31, 2009 and 2008, OMEC had accounts payable to other Calpine Corp. affiliates of $3.3 million and $3.9 million, respectively, arising in the ordinary course of business.

Amended and Restated Power Purchase Agreement

On May 1, 2007, OMEC entered into the PPA with SDG&E, a related party, to sell all power capacity of the Plant upon achieving commercial operations. The PPA has a term of ten years from the commencement of commercial operation of the Plant. Under the terms of the PPA, OMEC receives monthly payments, primarily consisting of a capacity component, variable operation and maintenance component and a start-up payment. In addition, SDG&E is responsible for fuel supply and transportation to the Plant.

The PPA meets the criteria of an operating lease, with the capacity payments levelized on a straight-line basis over the term of the agreement. Minimum payments due to OMEC under the PPA as of December 31, 2009, are as follows (in thousands):

2010	$ 72,553
2011	70,763
2012	70,763
2013	70,763
2014	70,763
Thereafter	337,960
Total	$ 693,565

At December 31, 2009 and 2008, OMEC had accounts receivable from SDG&E related to the PPA of $10.6 million and $0, respectively.

Under the terms of the PPA, OMEC was required to pay liquidating damages of $50,000 per day if commercial operations did not commence before the guaranteed commercial operations date of May 30, 2009. OMEC recorded liquidating damages to SDG&E totaling $6.1 million, which are included in the Statement of Operations for the year ended December 31, 2009.

Restated Interconnection Facility Agreement

On May 1, 2007, Calpine Corp. assigned the Restated Interconnections Facility Agreement ("RIFA") and Restated Interconnection Agreement ("RIA") with SDG&E to OMEC. The RIFA agreement requires SDG&E to design, engineer, construct and install the switchyard facilities and perform transmission upgrades in which OMEC will reimburse SDG&E. As of December 31, 2008, OMEC had recorded $22.7 million, including $8.6 million contributed from Calpine Corp., for network upgrades and accrued interest under the RIFA, which is included in deferred transmission credits, related party on the Balance Sheet. During the year ended December 31, 2009, additional upgrade costs and accrued interest totaling $0.8 million were recorded under the RIFA. At the Commercial Operations Date, OMEC was entitled to a repayment for the cost of the interconnection facilities that were considered network upgrades, including interest from the time the original payments were made. During the year ended December 31, 2009, OMEC received $23.5 million from SDG&E for repayment of the cost of transmission facilities.

9. Income Taxes

OMEC accrues taxes at the enacted statutory rates. The income tax provision reflected in the statements of operations for the years ended December 31, 2009 and 2008, consisted of the following (in thousands):

	2009	2008
Current:		
Federal	$ —	$ —
State	—	28
Total current	—	28
Deferred:		
Federal	—	—
State	—	—
Total deferred	—	—
Total income tax expense	$ —	$ 28

A reconciliation of the U.S. federal statutory rate of 35% to the effective tax rate for the years ended December 31, 2009 and 2008, is as follows:

	2009	2008
Federal statutory tax expense rate	35%	35%
Change in valuation allowance	(35)	(35)
Effective income tax expense rate	0%	0%

The components of deferred taxes as of December 31, 2009 and 2008, are as follows (in thousands):

	2009	2008
Deferred tax assets:		
Deferred financing costs	$ 122	$ 122
Derivative instruments	18,692	37,076
Written call option	20,219	20,219
Net operating loss carryover	20,430	2,495
Property, plant and equipment	78,175	85,783
Deferred tax assets before valuation allowance	137,638	145,695
Less: Valuation allowance	(118,080)	(125,476)
Total deferred tax assets	19,558	20,219
Deferred tax liabilities:		
Intangible asset	(19,496)	(20,219)
Prepaid expenses	(62)	—
Total deferred tax liabilities	(19,558)	(20,219)
Net deferred tax asset	—	—
Less: Current portion deferred tax asset	387	513
Deferred income taxes, net of current portion	$ (387)	$ (513)

For the year ended December 31, 2009, OMEC had U.S. federal and state NOL carryforwards of $50.3 million and $31.9 million, respectively, which will expire between 2022 and 2029 for both state and U.S. federal purposes if not utilized. These NOL carryforwards include the effects of activities conducted by Calpine Corp. on

OMEC's behalf from 2002 to April 30, 2007, prior to the Contribution Date. In addition, as a result of the bankruptcy filing discussed in Note 10 and other factors, Calpine Corp. concluded that impairment indicators existed for certain long-lived assets during 2005. These long-lived assets were evaluated for impairment based on probability-weighted alternatives of utilizing the assets versus reselling the assets to third parties. Prior to 2007, impairment and other charges totaling approximately $195.0 million were recorded to reduce the assets to their estimated realizable value which were included in Calpine Corp.'s original basis contributed to OMEC in May 2007 and resulted in a deferred tax asset.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. A valuation allowance is recorded when it is more likely than not that a deferred tax asset will not be realized. Based on the weight of available positive and negative evidence, management determined it was appropriate to record a valuation allowance on all deferred tax assets at both December 31, 2009 and 2008, to the extent not offset by taxable income generated by reversing temporary differences of the appropriate character within the carryback or carryforward periods. As a result, OMEC has provided a valuation allowance of $118.1 million and $125.5 million as of December 31, 2009 and 2008, respectively.

OMEC's unrecognized tax benefit decreased during 2009, due to elimination of the uncertain tax position. When the Plant achieved commercial operations, management reassessed the tax basis of the assets. As the tax basis of the assets was adjusted, the uncertain tax position was resolved. A reconciliation of the beginning and ending amount of the unrecognized tax benefits is as follows (in thousands):

	2009	2008
Balance, beginning of period	$ 2,107	$ 2,091
Increase related to current year tax positions	—	16
Decrease related to prior year tax positions	(2,107)	—
Balance, end of period	$ —	$ 2,107

10. Impact of Calpine Corp.'s Bankruptcy

On December 20, 2005, Calpine Corp. and certain of its subsidiaries, including CCMCI and COSCI, but not OMEC, filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court. The Calpine Debtors' plan of reorganization, as approved by its creditors, was confirmed by the Bankruptcy Court on December 19, 2007, and became effective on January 31, 2008. While OMEC was not a Calpine Debtor, it did have agreements with Calpine Debtors. During the bankruptcy cases, both CCMCI and COSCI assumed and continued to perform under their agreements with OMEC.

11. Commitments and Contingencies

Letter of Credit

As of December 31, 2008, OMEC had a letter of credit available, but not drawn upon, of $25.0 million. The purpose of the letter of credit was to secure OMEC's obligations to SDG&E during the construction period, as required under the PPA. The letter of credit was cancelled in October 2009.

Ground Sublease and Easement Agreement

On May 1, 2007, OMEC entered into the Sublease Agreement with Calpine Corp. Calpine Corp. subsequently assigned its leasehold interest under the Sublease Agreement to SDG&E. The Sublease Agreement expires on July 7, 2032, and has provisions for two ten-year renewal terms. As subrent under this agreement, OMEC shall pay to SDG&E base subrent equal to $1.00 per year and shall pay directly to the lessor on SDG&E's behalf all of the other amounts owing by SDG&E under the original ground lease (whether as rent, additional rent or otherwise) including taxes and similar charges that SDG&E is obligated to pay under the original ground lease. Under the Sublease Agreement, OMEC has an option to require SDG&E to sell its leasehold interest in the site to OMEC if the call and put options discussed in Note 3 are not exercised. Ground lease expense is levelized over the term of the agreement. Ground lease expense totaled $0.3 million and $0, net of expenses capitalized to property, plant and equipment of $0.9 million and $1.2 million, for the years ended December 31, 2009 and 2008, respectively. The Sublease Agreement is accounted for as an operating lease. Minimum lease payments are levelized over the term of the agreement, and the resulting deferred lease levelization liability is included in other long-term liabilities on the Balance Sheets.

As of December 31, 2009, minimum lease payments are as follows (in thousands):

2010	$ 903
2011	931
2012	958
2013	987
2014	1,017
Thereafter	23,801
Total	$ 28,597

Parcel One Lease Agreement

On May 1, 2007, Calpine Corp. assigned the Parcel One Lease Agreement to OMEC whereby OMEC paid an annual reservation fee, which was amortized monthly to construction in progress until such time as the land was parceled and available for lease. On January 10, 2008, OMEC made the annual reservation fee payment of $0.6 million. On June 17, 2008, the Parcel One Lease Agreement was amended to reflect reparcelization of the lessor's land and to identify the specific parcels, now called Parcel 1 and Parcel 2, which the lessor leased to OMEC. The amended lease expired on June 30, 2009, and was not renewed by OMEC.

Litigation

OMEC is involved in various legal and litigation matters arising in the normal course of business. Management does not expect that the outcome of these proceedings will have a material adverse effect on OMEC's financial position, results of operations or cash flows.

EXHIBIT INDEX

Exhibit Number	Description
2.1	Debtors' Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code (incorporated by reference to Exhibit 2.1 to Calpine's Current Report on Form 8-K filed with the SEC on December 27, 2007).
2.2	Findings of Fact, Conclusions of Law, and Order Confirming Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code (incorporated by reference to Exhibit 2.2 to Calpine's Current Report on Form 8-K filed with the SEC on December 27, 2007).
2.3	Purchase and Sale Agreement by and between Riverside Energy Center, LLC and Calpine Development Holdings, Inc., as Sellers and Public Service Company of Colorado, as Purchaser dated as of April 2, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed with the SEC on July 29, 2010).**, ††
2.4	Purchase Agreement by and among Pepco Holdings, Inc., Conectiv, LLC, Conectiv Energy Holding Company, LLC and New Development Holdings, LLC dated as of April 20, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on July 8, 2010).**
3.1	Amended and Restated Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3.1 to Calpine's Current Report on Form 8-K filed with the SEC on February 1, 2008).
3.2	Amended and Restated By-Laws of the Company (as amended through May 7, 2009) (incorporated by reference to Exhibit 3.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, filed with the SEC on July 31, 2009).
4.1	Indenture, dated as of September 30, 2003, among Gilroy Energy Center, LLC, each of Creed Energy Center, LLC and Goose Haven Energy Center, as guarantors, and Wilmington Trust Company, as trustee and collateral agent, including form of 4.00% senior secured notes due 2011 (incorporated by reference to Exhibit 4.6 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, filed with the SEC on November 13, 2003).
4.2	Third Priority Indenture, dated as of March 23, 2004, among Calpine Generating Company, LLC, CalGen Finance Corp. and Manufacturers and Traders Trust Company (as successor trustee to Wilmington Trust FSB), as trustee, including form of third priority secured floating rate notes due 2011 (incorporated by reference to Exhibit 4.21 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2003, filed with the SEC on March 25, 2004).
4.3	Indenture, dated May 19, 2009, among Calpine Construction Finance Company, L.P. and CCFC Finance Corp., the guarantors named therein, and Wilmington Trust Company, as trustee, including form of 8.00% senior secured notes due 2016 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on May 22, 2009).
4.4	Indenture, dated October 21, 2009, between the Company and Wilmington Trust Company, as trustee, including form of 7.25% senior secured notes due 2017 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on October 26, 2009).
4.5	Amended and Restated Indenture, dated May 25, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 8% Senior Secured Notes due 2019 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on May 25, 2010).

Exhibit Number	Description
4.6	Indenture, dated July 23, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.875% Senior Secured Notes due 2020 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on July 23, 2010).
4.7	Indenture, dated October 22, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.50% Senior Secured Notes due 2021 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on October 22, 2010).
4.8	Indenture, dated January 14, 2011, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.875% Senior Secured Notes due 2023 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on January 14 , 2011).
4.9	Registration Rights Agreement, dated January 31, 2008, among the Company and each Participating Shareholder named therein (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on February 6, 2008).
10.1	Financing Agreements.
10.1.1.1	Credit Agreement, dated as of January 31, 2008, among the Company, as borrower, Goldman Sachs Credit Partners L.P., Credit Suisse, Deutsche Bank Securities Inc. and Morgan Stanley Senior Funding, Inc., as co-documentation agents and as co-syndication agents, General Electric Capital Corporation, as sub-agent for the revolving lenders, Goldman Sachs Credit Partners L.P., as administrative agent and as collateral agent and each of the financial institutions from time to time party thereto (incorporated by reference to Exhibit 10.5 to Calpine's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2010 filed with the SEC on October 29, 2010).††
10.1.1.2	First Amendment to Credit Agreement and Second Amendment to Collateral Agency and Intercreditor Agreement, dated as of August 20, 2009, among the Company, certain of the Company's subsidiaries as guarantors, the financial institutions party thereto as lenders and Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on August 26, 2009).
10.1.1.3	Guaranty and Collateral Agreement, dated as of January 31, 2008, made by the Company and certain of the Company's subsidiaries party thereto in favor of Goldman Sachs Credit Partners, L.P., as collateral agent (incorporated by reference to Exhibit 10.1.3 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 29, 2008).
10.1.1.4	Credit Agreement dated as of June 8, 2010, among New Development Holdings, LLC, as Borrower, The Lenders Party Hereto and Credit Suisse AG, as Administrative Agent and Collateral Agent; Credit Suisse Securities (USA) LLC, Citigroup Global Markets Inc., and Deutsche Bank Securities Inc., as Joint Bookrunners and Joint Lead Arrangers; Credit Suisse AG as Syndication Agent; Credit Suisse AG, Citibank, N.A., and Deutsche Bank Trust Company Americas as Co-Documentation Agents (incorporated by reference to Exhibit 10.6 to Calpine's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2010 filed with the SEC on October 29, 2010).
10.1.1.5	Credit Agreement, dated as of December 10, 2010, among Calpine Corporation, Goldman Sachs Bank USA, as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, the lenders party thereto and other parties thereto (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on December 13, 2010).

Exhibit Number	Description
10.2	Management Contracts or Compensatory Plans or Arrangements.
10.2.1.1	Employment Agreement, dated August 10, 2008, between the Company and Jack A. Fusco (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on August 12, 2008).†
10.2.1.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (Jack A. Fusco) (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on August 12, 2008).†
10.2.1.3	Non-Qualified Stock Option Agreement between the Company and Jack Fusco, dated August 11, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on August 17, 2010).†
10.2.2	Letter Agreement, dated December 17, 2008, between the Company and Zamir Rauf (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on December 19, 2008).†
10.2.3.1	Letter Agreement, dated September 1, 2008, between the Company and John B. Hill (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on September 4, 2008).†
10.2.3.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (John B. Hill) (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on September 4, 2008).†
10.2.3.3	Non-Qualified Stock Option Agreement between the Company and John B. (Thad) Hill, dated August 11, 2010 (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on August 17, 2010).†
10.2.3.4	Non-Qualified Stock Option Agreement between the Company and John B. (Thad) Hill, dated November 3, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on November 5, 2010).†
10.2.4.1	Employment Agreement, dated August 11, 2008, between the Company and W. Thaddeus Miller (incorporated by reference to Exhibit 10.2.7 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed with the SEC on November 7, 2008).†
10.2.4.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (Thaddeus Miller) (incorporated by reference to Exhibit 4.4 to Calpine's Registration Statement on Form S-8 (Registration No. 333-153860) filed with the SEC on October 6, 2008).†
10.2.4.3	Non-Qualified Stock Option Agreement between the Company and W. Thaddeus Miller, dated August 11, 2010 (incorporated by reference to Exhibit 10.3 to Calpine's Current Report on Form 8-K filed with the SEC on August 17, 2010).†
10.2.5	Calpine Corporation U.S. Severance Program.†
10.2.6	Calpine Corporation 2010 Calpine Incentive Plan (incorporated by reference to Exhibit 10.6 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed with the SEC on July 29, 2010).†
10.2.7	Calpine Corporation 2009 Calpine Incentive Plan (incorporated by reference to Exhibit 10.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 8, 2009).†
10.2.7.1	The Amended and Restated Calpine Corporation 2008 Equity Incentive Plan (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on November 5, 2010).†

Exhibit Number	Description
10.2.7.2	Form of Non-Qualified Stock Option Agreement (Pursuant to the 2008 Equity Incentive Plan) (incorporated by reference to Exhibit 10.4.3 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.2.7.3	Form of Restricted Stock Agreement (Pursuant to the 2008 Equity Incentive Plan) (incorporated by reference to Exhibit 10.4.4 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.2.7.4	Director's Restricted Stock Unit Agreement (Pursuant to the 2008 Equity Incentive Plan) between the Company and Mr. William J. Patterson (incorporated by reference to Exhibit 10.4.6 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.2.7.5	Restricted Stock Unit Election Form between the Company and William J. Patterson (incorporated by reference to Exhibit 10.4.7 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.2.8	The Amended and Restated Calpine Corporation 2008 Director Incentive Plan (incorporated by reference to Appendix A to Calpine's Definitive Proxy Statement on Schedule 14A filed with the SEC on April 5, 2010).†
10.2.9	Calpine Corporation Change in Control and Severance Benefits Plan (incorporated by reference to Exhibit 10.2.10 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 25, 2010).†
10.2.10	Letter Agreement, dated December 30, 2008, between the Company and Jim D. Deidiker (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K fled with the SEC on January 8, 2009).†
10.2.11	Letter re Employment Offer, dated February 6, 2009, between the Company and Michael D. Rogers (incorporated by reference to Exhibit 10.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 7, 2009).†
18.1	Letter of preferability regarding change in accounting principle from PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm (incorporated by reference to Exhibit 18.1 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2009 filed with the SEC on February 25, 2010).
21.1	Subsidiaries of the Company.*
23.1	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.*
23.2	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.*
24.1	Power of Attorney of Officers and Directors of Calpine Corporation (set forth on the signature pages of this Report).*
31.1	Certification of the Chief Executive Officer Pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Certification of the Senior Vice President and Chief Financial Officer Pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32.1	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*

Exhibit Number	Description
101	The following financial statements from the Company's Annual Report on Form 10-K for the year ended December 31, 2010, filed with the Securities and Exchange Commission, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Operations, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Comprehensive Income (Loss) and Stockholders' Equity (Deficit) and (v) Notes to Condensed Consolidated Financial Statements, tagged as blocks of text.*

* Filed herewith.

† Management contract or compensatory plan or arrangement.

**Schedules omitted pursuant to Item 601(b)(2) of Regulation S-K. Calpine will furnish supplementally a copy of any omitted schedule to the SEC upon request.

††Portions of this exhibit have been omitted pursuant to a request for confidential treatment under Rule 24b-2 under the Securities Exchange Act of 1934.

Board of Directors

J. Stuart Ryan†
Chairman of the Board
Founding Owner and President, Rydout LLC

Frank Cassidy†
Retired President and Chief Operating Officer
PSEG Power LLC

Jack A. Fusco
President and Chief Executive Officer, Calpine Corp.

Robert Hinckley¤ *
Chairman and Managing Director, MCL Intellectual Property LLC

David Merritt¤
President, BC Partners, Inc.

W. Benjamin Moreland¤
President and Chief Executive Officer
Crown Castle International Corp.

Robert A. Mosbacher, Jr.† *
Chairman, Mosbacher Energy Company

William E. Oberndorf*
Founding Partner, SPO Advisory Corp.

Denise M. O'Leary† *
Private Venture Capital Investor

¤ Audit Committee
† Compensation Committee
* Nominating and Corporate Governance Committee

Executive Management

Jack A. Fusco
President and Chief Executive Officer

John B. (Thad) Hill
Executive Vice President and Chief Operating Officer

Zamir Rauf
Executive Vice President and Chief Financial Officer

W. Thaddeus Miller
Executive Vice President, Chief Legal Officer and Corporate Secretary

Gary M. Germeroth
Executive Vice President and Chief Risk Officer

General Information

Corporate Headquarters
Calpine Corporation
717 Texas Avenue, Suite 1000
Houston, Texas 77002
(713) 830-2000
www.calpine.com

Investor Relations
Calpine Corporation Investor Relations
(713) 830-8775
investor-relations@calpine.com

Independent Auditor
Pricewaterhouse Coopers LLP
Houston, Texas

Transfer Agent
Computershare, Inc.
P.O. Box 43078
Providence, RI 02940-3078
877-745-9351

Certifications
Jack A. Fusco and Zamir Rauf have provided certifications to the Securities and Exchange Commission as required by sections 302 and 906 of the Sarbanes-Oxley Act of 2002. These certifications are included as exhibits 31.1, 31.2 and 32.1 of the company's Form 10-K for the year ended December 31, 2010.

On March 1, 2011, Jack A. Fusco submitted an annual certification to the New York Stock Exchange ("NYSE") that stated he was not aware of any violation by the company of the NYSE corporate governance listing standards.

Form 10-K
The Company's Annual Report on Form 10-K for the year ended December 31, 2010, as filed with the Securities and Exchange Commission, is included in this report. Additional copies may be obtained without charge by writing:

Calpine Corporation
Attn: Investor Relations
717 Texas Avenue, Suite 1000
Houston, Texas 77002

Annual Meeting
The Annual Meeting of Shareholders of Calpine Corporation will be held on Wednesday, May 11, 2011, at 10 a.m. Central Time at the Magnolia Hotel located at 1100 Texas Ave., Houston, TX 77002. All shareholders are cordially invited to attend.

Stock Information
Calpine Corporation's common stock is listed on the NYSE under the symbol CPN.

Forward-Looking Statement
Certain statements made in this Annual Report by or on behalf of the Company that are not historical facts are intended to be forward-looking statements within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These statements are based on assumptions that the Company believes are reasonable; however, many important factors, as discussed under "Forward-Looking Statements" in the Company's Form 10-K for the year ended December 31, 2010, could cause the Company's results in the future to differ materially from the forward-looking statements made herein and in any other documents or oral presentations made by or on behalf of the Company.

CALPINE®
NYSE CPN

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