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

Form 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2009

Or

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

For the transition period from to

Commission File No. 001-12079

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

717 Texas Avenue, Suite 1000, Houston, Texas 77002
50 West San Fernando Street, San Jose, California 95113
(Former Address)

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. [X] Yes [ ] No

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

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 definition of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

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 Exchange Act). [ ] Yes [X] No

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 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. [X] Yes [ ] No

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date: 428,798,845 shares of Common Stock, par value $.001 per share, outstanding on May 5, 2009.

CALPINE CORPORATION AND SUBSIDIARIES

REPORT ON FORM 10-Q
For the Quarter Ended March 31, 2009

INDEX

Forward-Looking Information

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" 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:

- The uncertain length and severity of the current general financial and economic downturn and its impacts on our business including demand for our power and steam products, the ability of our counterparties to perform under their contracts with us and the cost and availability of capital and credit;
- Fluctuations in prices for commodities such as natural gas and power;
- The effects of fluctuations in liquidity and volatility in the energy commodities markets including our ability to hedge risks;
- The ability of our customers, suppliers, service providers and other contractual counterparties to perform under their contracts with us;
- Our ability to manage our significant liquidity needs and to comply with covenants under our Exit Credit Facility and other existing financing obligations;
- Financial results that may be volatile and may not reflect historical trends due to, among other things, general economic and market conditions outside of our control, the ability of our counterparties to perform their contracts with us and the effects of our Chapter 11 reorganization;
- Our ability to attract and retain customers and counterparties, including suppliers and service providers, and to manage our customer and counterparty exposure and credit risk, including our commodity positions;
- Competition, including risks associated with marketing and selling power in the evolving energy markets;
- 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 regions laws and regulations including those related to GHG emissions;
- Natural disasters such as hurricanes, earthquakes and floods that may impact our power plants or the markets our power plants serve;
- Seasonal fluctuations of our results and exposure to variations in weather patterns;
- Disruptions in or limitations on the transportation of natural gas and transmission of power;
- Our ability to attract, retain and motivate key employees;
- Our ability to implement our new business plan and strategy;
- Risks related to our geothermal resources, including the adequacy of our steam reserves, unusual or unexpected steam field well and pipeline maintenance requirements and variables associated with the injection of waste water to the steam reservoir;
- Present and possible future claims, litigation and enforcement actions, including our ability to complete the implementation of our Plan of Reorganization;
- The expiration or termination of our PPAs and the related results on revenues; and
- Risks associated with the operation, construction and development of power plants including unscheduled outages or delays and plant efficiencies;
- Other risks identified in this Report and our 2008 Form 10-K.

You should also carefully review other reports that we file with the SEC. We undertake no obligation to update any forward-looking statements, whether as a result of new information, future developments or otherwise.

Where You Can Find Other Information

We file annual, quarterly and other reports, proxy statements and other information with the SEC. You may obtain and copy any document we 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 can 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. 20549-1004. The SEC maintains an Internet website at http://www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. Our SEC filings, including exhibits filed herewith, are accessible through the Internet at that website.

Our reports on Forms 10-K, 10-Q and 8-K, and amendments to those reports as well as our other filings with the SEC, are available for download, free of charge, as soon as reasonably practicable after these reports are filed with the SEC, at our website at http://www.calpine.com. The content of our website is not a part of this Report. You may request a copy of our SEC filings, at no cost to you, by writing or telephoning us at: Calpine Corporation, 717 Texas Avenue, Suite 1000, Houston, TX 77002, attention: Investor Relations, telephone: (713) 830-8775. We will not send exhibits to the documents, unless the exhibits are specifically requested and you pay our fee for duplication and delivery.

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. 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
2008 Form 10-K	Calpine Corporation’s Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on February 27, 2009, as amended by Amendment No. 1 thereto on Form 10-K/A, filed with the SEC on March 31, 2009
Adjusted EBITDA	EBITDA adjusted to remove the income effects of (a) non-cash losses on sales, dispositions or impairments of assets, (b) any unrealized gains or losses and any non-cash realized gains or losses from accounting for derivatives, (c) non-cash stock compensation expense, (d) operating lease expense, (e) non-cash gains and losses from intercompany foreign currency translations, (f) reorganization items, (g) major maintenance expense, (h) any non-cash gain or loss on the repurchase or extinguishment of debt and (i) any other extraordinary, unusual or non-recurring income plus our net interest in the Adjusted EBITDA of our unconsolidated investments
AOCI	Accumulated Other Comprehensive Income
APB	Accounting Principles Board
Average availability	Availability represents the percent of total hours during the period that our plants were available to run after taking into account the downtime associated with both scheduled and unscheduled outages
Average capacity factor (excluding peakers)	The average capacity factor (excluding peakers) is 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 weighted average capacity during the period by (ii) the total hours in the period. The weighted average capacity reflects the seasonally adjusted capacity of our plants (except our mothballed plants) during the period, including any time the plants may not be operating due to scheduled and unscheduled outages for maintenance and repair requirements or because we elect not to generate when power prices are too low or natural gas prices are too high to operate profitably
Bankruptcy Code	U.S. Bankruptcy Code
Bankruptcy Courts	The U.S. Bankruptcy Court and the Canadian Court
BLM	Bureau of Land Management of the U.S. Department of the Interior
Blue Spruce	Blue Spruce Energy Center LLC
Bridge Facility	Bridge Loan Agreement, dated as of January 31, 2008, among Calpine Corporation as borrower, the lenders party thereto, Goldman Sachs Credit Partners L.P., Credit Suisse, Deutsche Bank Securities Inc. and Morgan Stanley Senior Funding Inc., as co-documentation agents, and Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent
Btu	British thermal unit(s), a measure of heat content
CAA	Federal Clean Air Act, United States Code Title 42, Chapter 85
CalGen	Calpine Generating Company, LLC

ABBREVIATION	DEFINITION
CalGen Third Lien Debt	Collectively, $680,000,000 Third Priority Secured Floating Rate Notes Due 2011, issued by CalGen and CalGen Finance Corp.; and $150,000,000 11 1/2% Third Priority Secured Notes Due 2011, issued by CalGen and CalGen Finance Corp., in each case repaid on March 29, 2007
Calpine Debtors	The U.S. Debtors and the Canadian Debtors
Calpine Equity Incentive Plans	Collectively, the MEIP and the DEIP, 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 have been 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
CCAA	Companies' Creditors Arrangement Act (Canada)
CCFC	Calpine Construction Finance Company, L.P
CFR	Code of Federal Regulations
Channel Energy Center	Our 593 MW natural gas-fired cogeneration power plant located in Houston, Texas
Chapter 11	Chapter 11 of the Bankruptcy Code
Cogeneration	Using a portion or all of the steam generated in the combined-cycle power generating process to supply a customer with 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
Commodity expense	The sum of our GAAP expenses from fuel expense, purchased power and natural gas expense including for hedging and optimization, 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
Commodity Margin	Non-GAAP financial measure that includes power and steam revenues, REC revenue, transmission revenue and expenses, fuel and purchased energy expense, 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 GAAP revenues from power and steam sales, sales of purchased power and natural gas, REC revenue, transmission revenue, and cash settlements from our marketing, hedging and optimization activities that are included in our mark-to-market activity in operating revenues
Company	Calpine Corporation, a Delaware corporation, and subsidiaries
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
Convertible Senior Notes	Collectively, Calpine Corporation's 4% Contingent Convertible Notes Due 2006, 6% Contingent Convertible Notes Due 2014, 7 3/4% Contingent Convertible Notes Due 2015 and 4 3/4% Contingent Convertible Senior Notes Due 2023
CPUC	California Public Utilities Commission

ABBREVIATION	DEFINITION
Deer Park	Deer Park Energy Center Limited Partnership
DEIP	Calpine Corporation 2008 Director Incentive Plan, which provides for grants of equity awards to non-employee members of Calpine’s Board of Directors
DIP	Debtor-in-possession
DIP Facility	The Revolving Credit, Term Loan and Guarantee Agreement, dated as of March 29, 2007, among the Company, as borrower, certain of the Company’s subsidiaries, as guarantors, the lenders party thereto, Credit Suisse, Goldman Sachs Credit Partners L.P. and JPMorgan Chase Bank, N.A., as co-syndication agents and co-documentation agents, General Electric Capital Corporation, as sub-agent, and Credit Suisse, as administrative agent and collateral agent, with Credit Suisse Securities (USA) LLC, Goldman Sachs Credit Partners L.P., JPMorgan Securities Inc., and Deutsche Bank Securities Inc. acting as Joint Lead Arrangers and Bookrunners
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
Emergence Date Market Capitalization	Determined as Calpine’s Market Capitalization using the 30-day weighted average stock price following the Effective Date
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
Exchange Act	U.S. Securities Exchange Act of 1934, as amended
Exit Credit Facility	Credit Agreement, dated as of January 31, 2008, among Calpine Corporation, as borrower, the lenders party thereto, General Electric Capital Corporation, as sub-agent, Goldman Sachs Credit Partners L.P., Credit Suisse, Deutsche Bank Securities Inc., and Morgan Stanley Senior Funding, Inc., as co-syndication agents and co-documentation agents, and Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent
Exit Facilities	Together, the Exit Credit Facility and the Bridge Facility
FASB	Financial Accounting Standards Board
FDIC	Federal Deposit Insurance Corporation
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
Fremont	Fremont Energy Center, LLC
FSP	FASB Staff Position
GAAP	Generally accepted accounting principles in the United States
GE	General Electric International, Inc.
Geysers Assets	17 (15 operating power plants with 17 turbines and two plants not in operation) geothermal power plant assets located in northern California
GHG	Greenhouse gas(es), primarily CO_2, and including methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs)
Greenfield LP	Greenfield Energy Centre LP
Heat Rate(s)	A measure of the amount of fuel required to produce a unit of power
Hillabee	Hillabee Energy Center, LLC
IRC	Internal Revenue Code

ABBREVIATION	DEFINITION
IRS	U.S. Internal Revenue Service
KWh	Kilowatt hour(s), a measure of power produced
LIBOR	London Inter-Bank Offered Rate
LSTC	Liabilities subject to compromise
Market Capitalization	Market value of Calpine Corporation common stock outstanding, calculated in accordance with the Calpine Corporation amended and restated certificate of incorporation
Market Heat Rate(s)	The regional power price divided by the corresponding regional natural gas price
MEIP	Calpine Corporation 2008 Equity Incentive Plan, which provides for grants of equity awards to Calpine employees and non-employee members of Calpine's Board of Directors
MMBtu	Million Btu
MW	Megawatt(s), a measure of plant performance
MWh	Megawatt hour(s), a measure of power produced
Ninth Circuit	U.S. Court of Appeals for the Ninth Circuit
NOL(s)	Net operating loss(es)
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OMEC	Otay Mesa Energy Center, LLC
OTC	Over-the-Counter
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
Plan of Reorganization	Debtors' 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
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 electric power product, including electric energy, 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 part of the consideration provided by the purchaser of an electric power product is the fuel required by the seller to generate such electric power
PUCT	Public Utility Commission of Texas
REC	Renewable Energy Credit
RockGen	RockGen Energy LLC
Rosetta	Rosetta Resource Inc.
SAB	Staff Accounting Bulletin
SDG&E	San Diego Gas & Electric Company
SDNY Court	U.S. District Court for the Southern District of New York

ABBREVIATION	DEFINITION
SEC	U.S. Securities and Exchange Commission
Second Circuit	U.S. Court of Appeals for the Second Circuit
Second Priority Debt	Collectively, the Second Priority Notes and Second Priority Senior Secured Term Loans Due 2007
Second Priority Notes	Calpine Corporation's Second Priority Senior Secured Floating Rate Notes Due 2007, 8 1/2% Second Priority Senior Secured Notes Due 2010, 8 3/4% Second Priority Senior Secured Notes Due 2013 and 9 7/8% Second Priority Senior Secured Notes Due 2011
Securities Act	U.S. Securities Act of 1933, as amended
SFAS	Statement of Financial Accounting Standards
SO_2	Sulfur dioxide
SOP 90-7	Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code"
Spark spread(s)	The difference between the sales price of power per MWh and the cost of fuel to produce it
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
TCEQ	Texas Commission on Environmental Quality
TMG	Turbine Maintenance Group
Unsecured Senior Notes	Collectively, Calpine Corporation's 7 5/8% Senior Notes due 2006, 10 1/2% Senior Notes due 2006, 8 3/4% Senior Notes due 2007, 7 7/8% Senior Notes due 2008, 7 3/4% Senior Notes due 2009, 8 5/8% Senior Notes due 2010 and 8 1/2% Senior Notes due 2011
U.S.	United States of America
U.S. Bankruptcy Court	U.S. Bankruptcy Court for the Southern District of New York
U.S. Debtors	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)
VAR	Value-at-risk
VIE(s)	Variable interest entity(ies)
Whitby	Whitby Cogeneration Limited Partnership

PART I — FINANCIAL INFORMATION

Item 1. ***Financial Statements***

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	March 31, 2009	December 31, 2008
	(in millions, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,626	$ 1,657
Accounts receivable, net of allowance of $40 and $37	656	850
Inventory	166	163
Margin deposits and other prepaid expense	474	776
Restricted cash, current	421	337
Current derivative assets	4,614	3,653
Other current assets	65	64
Total current assets	8,022	7,500
Property, plant and equipment, net	11,849	11,908
Restricted cash, net of current portion	55	166
Investments	163	144
Long-term derivative assets	602	404
Other assets	598	616
Total assets	$ 21,289	$ 20,738
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 442	$ 574
Accrued interest payable	48	85
Debt, current portion	740	716
Current derivative liabilities	4,436	3,799
Income taxes payable	9	5
Other current liabilities	259	437
Total current liabilities	5,934	5,616
Debt, net of current portion	9,735	9,756
Deferred income taxes, net of current portion	89	93
Long-term derivative liabilities	766	698
Other long-term liabilities	206	203
Total liabilities	16,730	16,366
Commitments and contingencies (see Note 12)		
Stockholders' equity:		
Preferred stock, $.001 par value per share; 100,000,000 shares authorized; none issued and outstanding at March 31, 2009 and December 31, 2008	—	—
Common stock, $.001 par value per share; 1,400,000,000 shares authorized; 429,111,851 shares issued and 428,812,216 shares outstanding at March 31, 2009; 429,025,057 shares issued and 428,960,025 shares outstanding at December 31, 2008	1	1
Treasury stock, at cost, 299,635 shares at March 31, 2009 and 65,032 shares at December 31, 2008	(3)	(1)
Additional paid-in capital	12,229	12,217
Accumulated deficit	(7,657)	(7,689)
Accumulated other comprehensive loss	(12)	(158)
Total Calpine stockholders' equity	4,558	4,370
Noncontrolling interest	1	2
Total stockholders' equity	4,559	4,372
Total liabilities and stockholders' equity	$ 21,289	$ 20,738

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(in millions, except share and per share amounts)	
Operating revenues	$ 1,677	$ 1,951
Cost of revenue:		
Fuel and purchased energy expense	1,015	1,605
Plant operating expense	248	232
Depreciation and amortization expense	109	111
Other cost of revenue	23	32
Total cost of revenue	1,395	1,980
Gross profit (loss)	282	(29)
Sales, general and other administrative expense	45	48
(Income) loss from unconsolidated investments in power plants	(17)	3
Other operating expense	3	2
Income (loss) from operations	251	(82)
Interest expense	210	419
Interest (income)	(6)	(13)
Other (income) expense, net	4	10
Income (loss) before reorganization items and income taxes	43	(498)
Reorganization items	3	(279)
Income (loss) before income taxes	40	(219)
Income tax expense (benefit)	9	(5)
Net income (loss)	31	(214)
Add: Net loss attributable to the noncontrolling interest	1	—
Net income (loss) attributable to Calpine	$ 32	$ (214)
Basic earnings (loss) per common share:		
Weighted average shares of common stock outstanding (in thousands)	485,362	485,000
Net income (loss) per common share attributable to Calpine – basic	$ 0.07	$ (0.44)
Diluted earnings (loss) per common share:		
Weighted average shares of common stock outstanding (in thousands)	485,595	485,000
Net income (loss) per common share attributable to Calpine – diluted	$ 0.07	$ (0.44)

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31, 2009	2008
	(in millions)	
Cash flows from operating activities:		
Net income (loss)	$ 31	$ (214)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation and amortization expense [1]	132	155
Deferred income taxes	10	64
Loss on sale of assets, excluding reorganization items	10	—
Mark-to-market activities, net	(126)	203
(Income) loss from unconsolidated investments in power plants	(17)	3
Stock-based compensation expense	13	6
Reorganization items	—	(325)
Other	5	5
Change in operating assets and liabilities:		
Accounts receivable	194	255
Derivative instruments	(114)	(111)
Other assets	300	(78)
Accounts payable, LSTC and accrued expenses	(200)	(21)
Other liabilities	(158)	(282)
Net cash provided by (used in) operating activities	80	(340)
Cash flows from investing activities:		
Purchases of property, plant and equipment	(51)	(56)
Disposals of property, plant and equipment	—	4
Proceeds from sale of power plants, turbines and investments	—	398
Cash acquired due to reconsolidation of Canadian Debtors and other foreign entities	—	64
Contributions to unconsolidated investments	(4)	—
Return of investment from unconsolidated investments	—	24
Decrease in restricted cash	27	43
Other	1	6
Net cash provided by (used in) investing activities	(27)	483
Cash flows from financing activities:		
Repayments of notes payable	(54)	(49)
Borrowings from notes payable	—	5
Repayments of project financing	(50)	(122)
Borrowings from project financing	64	90
Repayments of DIP Facility	—	(98)
Borrowings under Exit Credit Facility	—	2,723
Repayments on Exit Credit Facility	(15)	(455)
Repayments on Second Priority Debt	—	(3,672)
Repayments on capital leases	(22)	(18)
Redemptions of preferred interests	(4)	(5)
Financing costs	—	(175)
Other	(3)	(1)
Net cash used in financing activities	(84)	(1,777)
Net decrease in cash and cash equivalents	(31)	(1,634)
Cash and cash equivalents, beginning of period	1,657	1,915
Cash and cash equivalents, end of period	$ 1,626	$ 281

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

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS – (Continued)
(Unaudited)

	Three Months Ended March 31,	
	2009	2008
Cash paid (received) during the period for:		
Interest, net of amounts capitalized	$ 226	$ 470
Income taxes	$ —	$ 7
Reorganization items included in operating activities, net	$ 3	$ 67
Reorganization items included in investing activities, net	$ —	$ (414)
Supplemental disclosure of non-cash investing and financing activities:		
Settlement of commodity contract with project financing	$ 79	$ —
Increase in deferred finance costs with project financing	$ 7	$ —
Capital expenditures in accounts payable	$ 10	$ 11
Settlement of LSTC through issuance of reorganized Calpine Corporation common stock	$ —	$ 5,200
DIP Facility borrowings converted into exit financing under the Exit Facilities	$ —	$ 3,872
Settlement of Convertible Senior Notes and Unsecured Senior Notes with reorganized Calpine Corporation common stock	$ —	$ 3,703

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(1) Includes depreciation and amortization that is also recorded in sales, general and other administrative expense and interest expense on our Consolidated Condensed Statements of Operations.

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

1. Basis of Presentation and Summary of Significant Accounting Policies

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 the major competitive power markets in the U.S., including California and Texas. We sell wholesale power, steam, 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 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, commodity and financial derivative transactions to hedge our business risks and optimize our portfolio of power plants.

Basis of Interim Presentation — The accompanying unaudited interim Consolidated Condensed Financial Statements of Calpine Corporation, a Delaware corporation, and consolidated subsidiaries have been prepared pursuant to the rules and regulations of the SEC. In the opinion of management, the Consolidated Condensed Financial Statements include the adjustments necessary for a fair statement of the information required to be set forth therein. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted from these statements pursuant to such rules and regulations and, accordingly, these financial statements should be read in conjunction with our audited Consolidated Financial Statements for the year ended December 31, 2008, included in our 2008 Form 10-K. The results for interim periods are not necessarily indicative of the results for the entire year primarily due to seasonal fluctuations in our revenues, major maintenance expenses and volatility of commodity prices.

During the period January 1, 2008, 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. Our Consolidated Condensed Financial Statements have been prepared in accordance with SOP 90-7 which requires that our financial statements distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, 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 Condensed Statements of Operations. See Note 2 for further discussion of our Plan of Reorganization.

Canadian Subsidiaries — As a result of filings by the Canadian Debtors under the CCAA in the Canadian Court, we deconsolidated most of our Canadian Debtors and other foreign entities as of December 20, 2005, the Petition Date, as we determined that the administration of the CCAA proceedings in a jurisdiction other than that of the U.S. Debtors' Chapter 11 cases resulted in a loss of the elements of control necessary for consolidation and we fully impaired our investment in our Canadian Debtors and other foreign entities. On February 8, 2008, the Canadian Effective Date, the Canadian Court ordered and declared that the CCAA proceedings were terminated. The termination of the proceedings of the CCAA and our emergence under the Plan of Reorganization allowed us to maintain our equity interest in the Canadian Debtors and other foreign entities, whose principal assets include various working capital items and a 50% ownership interest in Whitby, an equity method investment, net of debt. As a result, we regained control over our Canadian Debtors and other foreign entities which were reconsolidated into our Consolidated Condensed Financial Statements as of the Canadian Effective Date.

We accounted for the reconsolidation under the purchase method in a manner similar to a step acquisition. The excess of the fair market value of the reconsolidated net assets over the carrying value of our investment balance of $0 amounted to approximately $133 million. We recorded the Canadian assets acquired and the liabilities assumed based on their estimated fair value, with the exception of Whitby. We reduced the fair value of our Whitby equity investment (approximately $62 million) to $0 on the Canadian Effective Date and recorded the $71 million balance of the excess as a gain in reorganization items on our 2008 Consolidated Statement of Operations.

Equity Method Investments — We record our net interest in VIEs where we have determined that we are not the primary beneficiary, our net interest in joint venture and our equity interests in less-than-majority-owned companies in which we exercise significant influence over operating and financial policies using the equity method of accounting. Our share of net income (loss) is calculated according to our equity ownership or according to the terms of the appropriate partnership agreement. See Note 4 for further discussion of our VIEs.

Reclassifications — Certain reclassifications have been made to our December 31, 2008, Consolidated Condensed Balance Sheet and our Consolidated Condensed Statements of Operations and Cash Flows for the three months ended March 31, 2008, to conform to the current period presentation. Our reclassifications are summarized as follows:

- We adopted the provisions of SFAS No. 160 effective January 1, 2009, and reclassified minority interest as noncontrolling interest, a component of Stockholders' Equity, on our Consolidated Condensed Balance Sheets and included "net loss attributable to the noncontrolling interest" as a separate component on our Consolidated Condensed Statements of Operations. See "Recent Accounting Pronouncements" for a further discussion regarding our adoption of this standard.
- Our (income) loss from unconsolidated investments in power plants was previously included with other operating expense, but is now included as a separate line item on our Consolidated Condensed Statements of Operations.
- Cash flows related to derivatives not designated as hedges are classified in operating activities on the Consolidated Condensed Statements of Cash Flows. Previously, these cash flows were classified within investing activities.

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

Concentrations of Credit Risk — Financial instruments that potentially subject us to credit risk consist of cash and cash equivalents, restricted cash, accounts 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 or its agencies. Additionally, we actively monitor the credit risk of our receivable and derivative counterparties. 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 end-user customers; however, we may require collateral in the future. For financial and commodity 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.

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 establish 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 March 31, 2009, and December 31, 2008, we had cash and cash equivalents of $202 million and $296 million, respectively, that were subject to such project finance facilities and lease agreements.

Restricted Cash — We are required to maintain cash balances that are restricted by provisions of certain of our debt and lease agreements or other operating agreements. 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 in the Consolidated Condensed Balance Sheets and Statements of Cash Flows.

The table below represents the components of our restricted cash as of March 31, 2009, and December 31, 2008 (in millions):

	March 31, 2009			December 31, 2008		
	Current	Non-Current	Total	Current	Non-Current	Total
Debt service	$ 159	$ 26	$ 185	$ 102	$ 121	$ 223
Rent reserve	17	—	17	34	—	34
Construction/major maintenance	88	20	108	72	18	90
Security/project	80	1	81	96	1	97
Collateralized letters of credit and other credit support	25	—	25	7	1	8
Other	52	8	60	26	25	51
Total	$ 421	$ 55	$ 476	$ 337	$ 166	$ 503

Income Taxes — For federal income tax reporting purposes our consolidated 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. This is due to a preferred financing transaction in 2005 that resulted in the deconsolidation of the CCFC group for income tax purposes. The CCFC group does not have a valuation allowance recorded against its deferred tax assets, whereas the Calpine group continues to have a valuation allowance. For the three months ended March 31, 2009, we used the annual effective rate method to determine both our CCFC and Calpine groups' tax provision; however, our income tax rates did not bear a customary relationship to statutory income tax rates as a result of the impact of state income taxes, changes in unrecognized tax benefits, the Calpine group valuation allowance, and intraperiod tax allocations as discussed below. Our imputed tax rate for the three months ended March 31, 2009, was approximately 23%. For the three months ended March 31, 2008, we determined that the effective tax rate method for computing the tax provision did not provide meaningful results because of the uncertainty in reliably estimating our 2008 annual effective tax rate. As a result, we calculated our first quarter 2008 tax provision based on an actual, or discrete, method. Under this method, we determined the CCFC group and the Calpine group tax expense based upon actual results as if the interim period were an annual period. For the three months ended March 31, 2009 and 2008, our consolidated income tax expense (benefit) was $9 million and $(5) million, respectively. In accordance with intraperiod tax allocation provisions, our income tax expense included $13 million and nil on our Consolidated Condensed Statements of Operations for the three months ended March 31, 2009 and 2008, respectively, with an offsetting tax benefit to OCI.

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 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 the Plan of Reorganization. However, this ownership change is not expected to result in the expiration of our NOL carryforwards as a result of the annual limitations 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 prevent the risk of loss of 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 in the following circumstances: 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. During 2008, and through the filing of this Report, we experienced significant declines in our stock price from our Emergence Date Market Capitalization and, as of the filing of this Report, we have exceeded the 35% Market Capitalization decline threshold discussed above. As of the filing of this Report, our shift in ownership is approximately 13%. These restrictions are not currently operative but could become operative in the future if the foregoing events occur and our Board of Directors elects to impose them. 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.

We have filed a registration statement on Form S-3 registering the resale of the common stock held by two groups of related holders of our common stock that collectively owned approximately 47% of our common stock at March 31, 2009, (approximately 42% as of the filing of this Report, following sales by one of the holders of approximately 20.7 million shares in April and May 2009) 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. If these shareholders sought to sell all of their remaining registered shares within a short period of time, pursuant to the Form S-3 or otherwise, it would result in a shift in ownership of greater than 25 percentage points and our Board of Directors could elect to impose certain trading restrictions on our common stock as described above.

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. 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. We have provided a valuation allowance on certain federal, state and foreign tax jurisdiction deferred tax assets to reduce the gross amount of these assets to the extent necessary to result in an amount that is more likely than not of being realized. Projected future income from reversals of existing taxable temporary differences and tax planning strategies allowed a larger portion of the deferred tax assets to be offset against deferred tax liabilities resulting in a significant release of previously recorded valuation allowance.

As of March 31, 2009, we had unrecognized tax benefits of $96 million. If recognized, $39 million of our unrecognized tax benefits could impact the annual effective tax rate and $57 million related to deferred tax assets could be offset against the recorded valuation allowance within the next 12 months. We also had accrued interest and penalties of $16 million for income tax matters as of March 31, 2009. The amount of unrecognized tax benefits increased by $6 million for the three months ended March 31, 2009, primarily as a result of an increase of approximately $9 million for withholding taxes and reductions of approximately $3 million due to settlements with various state taxing authorities. We believe it is reasonably possible that a decrease of up to $7 million in unrecognized tax benefits could occur within the next 12 months primarily related to penalty and interest for federal and foreign tax filings as well as state tax liabilities as a result of settlements with the tax authorities.

We expect to file our 2008 U.S. federal income tax return on or before the due date of September 15, 2009. Our U.S. federal income tax return for 2007 remains subject to IRS examination. In addition, any NOLs claimed in future return years are subject to IRS examination regardless of when the NOLs occurred. We remain subject to various audits and reviews by state taxing authorities for other years; but do not expect these will have a material effect on our tax provision. Due to significant NOLs incurred in these years, any adjustment of state returns or federal returns from 2007 and forward would likely result in a reduction of deferred tax assets rather than a cash payment of taxes.

Recent Accounting Pronouncements

SFAS No. 157 — In September 2006, FASB issued SFAS No. 157, "Fair Value Measurements," which became effective for fiscal years beginning after November 15, 2007, and for interim periods within those years. SFAS No. 157 defines fair value, establishes a framework for measuring fair value under GAAP, and enhances disclosures about fair value measurements. SFAS No. 157 applies when other accounting pronouncements require fair value measurements; it does not require any new fair value measurements. In February 2008, FASB issued FSP No. FAS 157-2, "Effective Date of FASB Statement No. 157," which defers the effective date of SFAS No. 157 for non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years and interim periods beginning after November 15, 2008. We have certain potential non-recurring, non-financial assets and non-financial liabilities recorded at fair value that fall within the scope of FSP No. FAS 157-2 that include asset retirement obligations initially measured at fair value and long-lived assets measured at fair value for impairment testing. We adopted SFAS No. 157 as of January 1, 2008, related to financial assets and financial liabilities. We adopted SFAS No. 157 as of January 1, 2009, related to non-financial assets and non-financial liabilities, which did not have a material effect on our results of operations, cash flows or financial position; however, adoption may impact measurements of asset impairments and asset retirement obligations if they occur in the future.

FASB Staff Position No. FAS 157-4 — In April 2009, FASB issued FSP No. FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly." Among other things, FSP No. FAS 157-4:

- affirms that the objective of fair value, when the market for an asset is not active, is the price that would be received to sell the asset in an orderly transaction;
- clarifies and includes additional factors for determining whether there has been a significant decrease in market activity for an asset when the market for that asset is not active;
- eliminates the proposed presumption that all transactions are distressed (not orderly) in favor of a conclusion about whether a transaction was not orderly based on the weight of the evidence;
- includes an example that provides additional explanation on estimating fair value when the market activity for an asset has declined significantly;
- requires an entity to disclose a change in valuation technique (and the related inputs) resulting from the application of the FSP and to quantify its effects, if practicable; and
- applies to all fair value measurements when appropriate.

FSP No. FAS 157-4 must be applied prospectively and retrospective application is not permitted. FSP No. FAS 157-4 is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We did not elect to early adopt the requirements of this standard as of March 31, 2009, and do not expect adoption of this standard will have a material impact on our results of operations, cash flows or financial position.

SFAS No. 141(R) — In December 2007, FASB issued SFAS No. 141(R), "Business Combinations," which replaces SFAS No. 141. SFAS No. 141(R) establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. In addition, SFAS No. 141(R) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase. SFAS No. 141(R) also establishes disclosure requirements to enable users to evaluate the nature and financial effects of the business combination. In April 2009, FASB issued FSP No. FAS 141(R)-1, "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arises from Contingencies," which amends and clarifies SFAS No. 141(R) on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. SFAS No. 141(R) and FSP No. FAS 141(R)-1 are effective as of the beginning of an entity's fiscal year that begins after December 15, 2008, with early adoption prohibited. We adopted SFAS No. 141(R) and FSP No. FAS 141(R)-1 effective January 1, 2009. Adoption of these standards did not have a material effect on our results of operations, cash flows or financial position.

SFAS No. 160 — In December 2007, FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – An Amendment of ARB No. 51." SFAS No. 160 establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, and changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary. In addition, SFAS No. 160 establishes principles for valuation of retained noncontrolling equity investments and measurement of gain or loss when a subsidiary is deconsolidated. SFAS No. 160 also establishes disclosure requirements to clearly identify and distinguish between interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 is effective for fiscal years and interim periods beginning after December 15, 2008, with early adoption prohibited. We adopted SFAS No. 160 as of January 1, 2009, which did not have a material impact on our results of operations, financial position or cash flows; however, did result in the reclassification of minority interest to noncontrolling interest on our Consolidated Condensed Balance Sheets and Statements of Operations.

SFAS No. 161 — In March 2008, FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – An Amendment of FASB Statement No. 133." SFAS No. 161 requires enhanced disclosures about 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. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008, with early adoption encouraged. We adopted SFAS No. 161 as of January 1, 2009. Adoption of this standard resulted in additional disclosures related to our derivatives and hedging activities. Adoption of SFAS No. 161 requirements impacted our derivative and hedging disclosures to include our objectives for entering into derivative transactions, increased balance sheet and financial performance disclosures, volume information and credit enhancement disclosures. See Note 9 for a discussion of our additional disclosures.

FASB Staff Position No. FAS 107-1 and APB 28-1 — In April 2009, FASB issued FSP No. FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments." FSP No. FAS 107-1 and APB 28-1 amends FASB Statement No. 107, "Disclosures about Fair Value of Financial Instruments," as well as APB Opinion No. 28, "Interim Financial Reporting," to require disclosures about fair value of financial instruments in interim financial statements as well as in annual financial statements. FSP No. FAS 107-1 and APB 28-1 is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We did not elect to early adopt the requirements of this standard and will adopt this standard in the second quarter 2009. We do not expect the adoption of this standard will have a material impact on our results of operations, cash flows or financial position; however, adoption may impact future presentation and disclosure within our Notes to Consolidated Condensed Financial Statements.

FASB Staff Position No. FAS 133-1 and FIN 45-4 — In September 2008, FASB issued FSP No. FAS 133-1 and FIN 45-4, "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161." This FSP requires enhanced disclosures for credit derivatives and certain guarantees about the potential adverse effects of changes in credit risk, financial position, financial performance and cash flows of an entity selling credit derivatives. FSP No. FAS 133-1 and FIN 45-4 is effective for fiscal years and interim periods beginning after November 15, 2008, with early adoption encouraged. FSP No. FAS 133-1 and FIN 45-4 introduce enhanced disclosures specific to credit derivatives and certain guarantees. We adopted FSP No. FAS 133-1 and FIN 45-4 as of January 1, 2009. Currently, we do not have instruments that meet the requirements for additional disclosure, and adoption of this standard did not have any impact on our results of operations, cash flows or financial position.

2. Our Emergence from Chapter 11

From December 20, 2005, through January 31, 2008, the U.S. Debtors operated as debtors-in-possession under the protection of the U.S. Bankruptcy Court. In addition, the Canadian Debtors operated as debtors-in-possession under the jurisdiction of the Canadian Court from December 20, 2005, through February 8, 2008, the date on which the Canadian Court ordered and declared that the Canadian Debtors' proceedings under the CCAA were terminated.

Our Plan of Reorganization provides for the treatment of claims against and interests in the U.S. Debtors. Allowed administrative, tax and secured claims generally have been or are being paid in cash and cash equivalents or, with respect to certain secured claims, had the collateral securing such claims returned to the secured creditor. Allowed unsecured claims generally have been or are being paid with a distribution of common stock. Pursuant to the Plan of Reorganization, 485 million shares of common stock were authorized to be issued to settle such claims.

Through the filing of this Report, approximately 427 million shares have been distributed to holders of allowed unsecured claims, approximately 10 million shares are being held pending resolution of certain inter-creditor matters and approximately 48 million shares remain in reserve for distribution to holders of disputed claims whose claims ultimately become allowed. We estimate that the number of shares reserved is sufficient to satisfy the U.S. Debtors' obligations under the Plan of Reorganization even if all disputed unsecured 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. 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. Accordingly, resolution of these claims could have a material effect on creditor recoveries under the Plan of Reorganization as the total number of shares of common stock that remain available for distribution upon resolution of disputed claims is limited pursuant to the 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 the Plan of Reorganization for such claims is insufficient in value to satisfy such claims in full. No assurances can be given that settlements may not be materially higher or lower than confirmed in the Plan of Reorganization or than we originally estimated.

Interest Expense — During the first quarter of 2008, we recorded $135 million in post-petition interest from January 1, 2008, through the Effective Date related to our emergence from Chapter 11.

Reorganization Items — Reorganization items represent the direct and incremental costs related to our Chapter 11 cases. These include professional fees, pre-petition liability claim adjustments and losses that are probable and can be estimated, net of interest income earned on accumulated cash during the Chapter 11 process and net of gains on the sale of assets or resulting from certain settlement agreements related to our restructuring activities. Our total reorganization items for the three months ended March 31, 2009 and 2008, were expenses of $3 million and gains of $279 million, respectively. The major component of our reorganization items for the three months ended March 31, 2009, consisted of professional fees of approximately $2 million. The major components of our reorganization items for the three months ended March 31, 2008, primarily consisted of gains on asset sales of $203 million, for the sales of the Hillabee and Fremont development project assets (see Note 5 for further discussion of our sales of Hillabee and Fremont) and a gain of approximately $70 million on reconsolidation of our Canadian Debtors and other foreign entities. We expect to continue to pay professional and trustee fees related to our Chapter 11 cases through 2009 until the claims resolution process is completed and our Chapter 11 case is formally dismissed by the U.S. Bankruptcy Court.

3. Property, Plant and Equipment, Net

As of March 31, 2009, and December 31, 2008, the components of property, plant and equipment are stated at cost less accumulated depreciation as follows (in millions):

	March 31, 2009	December 31, 2008
Buildings, machinery and equipment	$ 13,373	$ 13,360
Geothermal properties	997	979
Other	261	258
	14,631	14,597
Less: Accumulated depreciation	(3,034)	(2,932)
	11,597	11,665
Land	76	76
Construction in progress	176	167
Property, plant and equipment, net	$ 11,849	$ 11,908

4. Variable Interest Entities and Unconsolidated Investments

We consolidate all VIEs where we are the primary beneficiary. This determination is made at the inception of our involvement with the VIE and is updated only in response to a reconsideration event. We consider both qualitative and quantitative factors to form a conclusion as to whether we, or another interest holder, absorbs a majority of the entity's risk for expected losses, receives a majority of the entity's potential for expected residual returns, or both. Our consolidated VIEs are aggregated into the following classifications in order of priority:

Consolidated VIEs with a Purchase Option — Certain of our subsidiaries have PPAs or other agreements that provide third parties the option to purchase power plant assets named in the agreement, an equity interest in a named generating asset, or a portion of the future cash flows generated from the asset. For these VIEs, we determined at the time we entered into the contractual arrangement giving rise to the purchase option that consolidation was appropriate because exercise of the option was considered unlikely or was only for a minority interest.

Consolidated Subsidiaries with Project Debt — Certain of our subsidiaries have project debt that contains provisions which we have determined create variability such as (i) capital stock or partnership interests, physical assets, contracts and/or cash flows that have been pledged to third parties as collateral, (ii) limits or restrictions on transfers of cash or other assets and/or (iii) a priority interest in favor of the lender in the cash flows of the project during the repayment period. Under these project financings, we have determined that the lenders' recourse, and consequently their risk of loss, is limited to such collateral or priority interest. 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. Due to the secured interests and/or lender priority in distribution, we have determined that we retain the primary risk of loss associated with the projects and that we are the primary beneficiary of these VIEs. In addition, we retain ownership and absorb the full risk of loss and potential for reward once the project debt is paid in full. See Note 7 for further information regarding our project debt and Note 1 for information regarding our restricted cash balances.

Consolidated Subsidiaries with PPAs — Certain of our 100% owned subsidiaries have PPAs that may serve to transfer the risk of loss of the entity to our counterparty under the PPA and thus constitute a VIE as the PPA is deemed to be a form of subordinated financial support. For all such VIEs we have determined that we are the primary beneficiary as we retain the primary risk of loss over the life of the project.

Other Consolidated VIEs — Our other consolidated VIEs primarily consist of monetized assets secured by financing. For each of these arrangements we are the primary beneficiary as we retain both the primary risk of loss and potential for reward associated with the assets of the subsidiary.

The table below details the assets and liabilities (excluding intercompany balances which are eliminated in consolidation) for our VIEs, combined by VIE classification, that are included in our Consolidated Condensed Balance Sheets as of March 31, 2009, and December 31, 2008 (in millions):

Condensed Combined VIE Assets and Liabilities

	March 31, 2009			
	Purchase Options[(1)]	**Project Debt**	**PPAs**	**Other**
Assets:				
Current assets	$ 205	$ 296	$ 108	$ 185
Restricted cash, net of current portion	13	16	17	—
Property, plant and equipment, net	2,651	3,156	1,320	—
Other assets	84	47	6	—
Total assets	$ 2,953	$ 3,515	$ 1,451	$ 185
Liabilities:				
Current liabilities	$ 193	$ 392	$ 18	$ 220
Long-term debt	1,208	1,648	—	—
Long-term derivative liabilities	10	14	—	—
Other liabilities	12	10	10	—
Total liabilities	$ 1,423	$ 2,064	$ 28	$ 220

	December 31, 2008			
	Purchase Options[(1)]	**Project Debt**	**PPAs**	**Other**
Assets:				
Current assets	$ 224	$ 369	$ 152	$ 103
Restricted cash, net of current portion	3	16	27	111
Property, plant and equipment, net	2,863	2,438	1,413	—
Other assets	94	32	7	4
Total assets	$ 3,184	$ 2,855	$ 1,599	$ 218
Liabilities:				
Current liabilities	$ 204	$ 412	$ 33	$ 142
Long-term debt	1,413	1,313	58	131
Long-term derivative liabilities	11	14	—	—
Other liabilities	10	5	9	—
Total liabilities	$ 1,638	$ 1,744	$ 100	$ 273

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(1) The assets and liabilities listed above for our VIEs with purchase options may not be indicative of our risk of loss. Some of the assets and liabilities above include VIEs where the sale options are held by us, some are for only a minority interest, some are effective only upon the occurrence of an event of default and some are only for a portion of a total VIE's assets and liabilities.

Unconsolidated VIEs and Investments

We do not consolidate VIEs where we have determined that we are not the primary beneficiary. We also have joint venture and equity interests, accounted for under the voting interests model, where we do not have control and do not consolidate. We account for our unconsolidated VIEs, joint venture and equity interests under the equity method of accounting and include our net equity interest in investments on our Consolidated Condensed Balance Sheets. Our equity interest in the net income from our unconsolidated VIEs, joint venture and equity interests is recorded in (income) loss from unconsolidated investments in power plants on a net basis.

At March 31, 2009, and December 31, 2008, our equity method investments included on our Consolidated Condensed Balance Sheets were comprised of the following (in millions):

	Ownership Interest as of March 31, 2009	March 31, 2009	December 31, 2008
OMEC	100%	$ 111	$ 98
Greenfield LP	50%	52	46
Whitby	50%	—	—
Total investments		$ 163	$ 144

OMEC — OMEC, an indirect wholly owned subsidiary, is the owner of the Otay Mesa Energy Center, a 596 MW natural gas-fired power plant currently under construction in southern San Diego County, California. We do not consolidate OMEC as a result of a ten-year tolling agreement we entered into with SDG&E and assignment of rights under an existing ground lease and ground sublease and easement agreement to SDG&E in May 2007. The assignment of the ground lease and ground sublease, among other things, provides for a put option by OMEC to sell for $280 million, and a call option by SDG&E to buy for $377 million, the Otay Mesa Energy Center at the end of the tolling agreement. We considered that OMEC was designed to create and pass along construction, operational and credit risk to us; however, we determined SDG&E has a greater variability of risk compared to us. We determined our exposure to risk is limited to the operations during the ten-year period and to the extent the plant value in year ten is between $280 million and $377 million.

OMEC has a $377 million non-recourse project finance facility to finance the construction of Otay Mesa Energy Center. The project finance facility is structured as a construction loan, converting to a term loan upon commercial operation of Otay Mesa Energy Center, and matures in April 2019. Borrowings under the project finance facility are initially priced at LIBOR plus 1.5%. We contributed $4 million and nil during the three months ended March 31, 2009 and 2008, respectively, as an additional investment in OMEC. We received nil in distributions for both the three months ended March 31, 2009 and 2008, respectively.

Greenfield LP — Greenfield LP is a limited partnership between certain subsidiaries of ours and of Mitsui & Co., Ltd., which operates the Greenfield Energy Centre, a 1,005 MW natural gas-fired power plant in Ontario, Canada. We and Mitsui & Co., Ltd. each hold a 50% interest in Greenfield LP. Greenfield LP holds an 18-year construction term loan in the amount of Can$648 million. Borrowings under the project finance facility are initially priced at Canadian LIBOR plus 1.2% or Canadian prime rate plus 0.2%.

Whitby — Represents our 50% investment in Whitby held by our Canadian subsidiaries, which was reconsolidated on the Canadian Effective Date.

The following details our (income) loss and distributions from unconsolidated investments in power plants for the three months ended March 31, 2009 and 2008 (in millions):

	(Income) Loss from Unconsolidated Investments in Power Plants		Distributions	
	2009	2008	2009	2008
OMEC	$ (10)	$ —	$ —	$ —
Greenfield LP	(5)	6	—	24
RockGen	—	(3)	—	—
Whitby	(2)	—	2	—
Total	$ (17)	$ 3	$ 2	$ 24

RockGen — During the first quarter of 2008, we deconsolidated RockGen and subsequently reconsolidated RockGen in December 2008.

Our risk of loss related to our unconsolidated VIEs is limited to our investment balance and our construction and operational risk related to OMEC as defined above. The debt on the books of our unconsolidated investments is not reflected on our Consolidated Condensed Balance Sheets. As of March 31, 2009, and December 31, 2008, equity method investee debt was approximately $714 million and $697 million, respectively. Based on our pro rata share of each of the investments, our share of such debt would be approximately $497 million and $477 million as of March 31, 2009, and December 31, 2008, respectively. All such debt is non-recourse to us.

Inland Empire Energy Center Put Option — We hold a call option to purchase the Inland Empire Energy Center development project (a 775 MW natural gas-fired power plant located in California) from GE. The call option may be exercised between years 7 and 14 of the life of the power plant. Additionally, GE holds a put option whereby they can require us to purchase the project, if certain plant performance criteria are met during year 15 of the life of the power plant. An analysis was completed to determine whether or not we were the primary beneficiary of the Inland Empire power plant upon execution of the arrangement. We determined that we were not the primary beneficiary of the Inland Empire project as we do not absorb the majority of the risk of loss associated with the project through holding the call option to purchase the project. This conclusion was reached through consideration of factors including, but not limited to, the fact that GE will manage and fully fund the construction effort of the project, and upon reaching commercial operations, manage and operate the project. Additionally, if we purchase the project under the call or put options, GE will continue to provide critical plant maintenance services throughout the remaining estimated useful life of the project.

Significant Subsidiary — OMEC meets the definition of a significant subsidiary based upon the relationship of our net income from our investment to our consolidated net income. The Condensed Statements of Operations for OMEC for the three months ended March 31, 2009 and 2008, is set forth below (in millions):

OMEC
Condensed Statements of Operations

	2009	2008
Revenues	$ —	$ —
Operating expenses	1	—
Loss from operations	(1)	—
Interest (income) expense[1]	(11)	—
Other (income) expense, net	—	—
Net income	$ 10	$ —

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(1) Interest income is the result of unrealized mark-to-market gains from an interest rate swap contract.

5. Asset Sales

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.

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.

The sales of the Hillabee and Fremont 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.

6. Comprehensive Income (Loss)

Comprehensive income (loss) is the total of net income (loss) and all other non-owner changes in equity. Comprehensive income (loss) includes our net income (loss), unrealized gains and losses from derivative instruments, net of tax that qualify as cash flow hedges, our share of equity method investees' OCI and the effects of foreign currency translation adjustments. We report AOCI on our Consolidated Condensed Balance Sheets. The table below details the components of our comprehensive income (loss) during the three months ended March 31, 2009 and 2008 (in millions):

	2009	2008
Net income (loss)	$ 31	$ (214)
Other comprehensive income (loss):		
Gain (loss) on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income	202	(404)
Reclassification adjustment for cash flow hedges realized in net income	(67)	10
Foreign currency translation loss	(2)	(6)
Income tax expense	13	—
Total comprehensive income (loss)	$ 177	$ (614)

7. Debt

Our debt at March 31, 2009, and December 31, 2008, was as follows (in millions):

	March 31, 2009	December 31, 2008
Exit Credit Facility	$ 6,630	$ 6,645
Commodity Collateral Revolver	100	100
Project financing	1,627	1,525
CCFC financing	776	778
Preferred interests	331	335
Notes payable and other borrowings	301	356
Capital lease obligations	710	733
Total debt	10,475	10,472
Less: Current maturities	740	716
Debt, net of current portion	$ 9,735	$ 9,756

Exit Credit Facility — As of March 31, 2009, and December 31, 2008, our primary debt facility was the Exit Credit Facility. The Exit Credit Facility includes (i) approximately $6.0 billion of senior secured term loans; (ii) a $1.0 billion senior secured revolving facility; and (iii) the ability to raise up to $2.0 billion of incremental term loans available on a senior secured basis in order to refinance secured debt of subsidiaries under an "accordion" provision subject to market conditions.

As of March 31, 2009, under the Exit Credit Facility we had approximately $5.9 billion outstanding under the term loan facilities, $725 million outstanding under the revolving credit facility and $230 million of letters of credit issued against the revolving credit facility. Borrowings under the Exit Credit Facility bear interest at a floating rate, at our option, of LIBOR plus 2.875% per annum or base rate plus 1.875% per annum. Borrowings under the Exit Credit Facility term loan facility require quarterly payments of principal equal to 0.25% of the original principal amount of the term loan. The Exit Credit Facility matures on March 29, 2014.

The obligations under the Exit Credit Facility are unconditionally guaranteed by certain of our direct and indirect domestic subsidiaries and are secured by a security interest in substantially all of the tangible and intangible assets of Calpine Corporation and the guarantors. The obligations under the Exit Credit Facility are also secured by a pledge of the equity interests of the direct subsidiaries of each guarantor, subject to certain exceptions, including exceptions for equity interests in foreign subsidiaries, existing contractual prohibitions and prohibitions under other legal requirements. The Exit Credit Facility contains restrictions, including limiting our ability to, among other things:

- Incur additional indebtedness and issue stock;
- Make prepayments on or purchase indebtedness in whole or in part;

- Pay dividends and other distributions with respect to our stock or repurchase our stock or make other restricted payments;
- Use money borrowed under the Exit Credit Facility for non-guarantors (including foreign subsidiaries);
- Make certain investments;
- Create or incur liens to secure debt;
- Consolidate or merge with another entity, or allow one of our subsidiaries to do so;
- Lease, transfer or sell assets and use proceeds of permitted asset leases, transfers or sales;
- Limit dividends or other distributions from certain subsidiaries up to Calpine Corporation;
- Make capital expenditures beyond specified limits;
- Engage in certain business activities; and
- Acquire power plants or other businesses.

The Exit Credit Facility also requires compliance with financial covenants that include (i) a maximum ratio of total net debt to Consolidated EBITDA (as defined in the Exit Credit Facility), (ii) a minimum ratio of Consolidated EBITDA to cash interest expense and (iii) a maximum ratio of total senior net debt to Consolidated EBITDA.

Other Financing Activities — On January 21, 2009, Deer Park, our indirect wholly owned subsidiary, closed on $156 million of senior secured credit facilities, which includes 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, fund approximately $22 million in restricted cash and the remainder was distributed to Calpine Corporation for general corporate purposes. The senior term loan facility matures on January 21, 2012, and bears interest at Deer Park's option of LIBOR plus 3.5% or base rate plus 2.5%.

Letter of Credit Facilities — The table below represents amounts outstanding under our letter of credit facilities as of March 31, 2009, and December 31, 2008 (in millions):

	March 31, 2009	December 31, 2008
Exit Credit Facility	$ 230	$ 259
Calpine Development Holdings, Inc.	148	148
Knock-in Facility	30	50
Various project financing facilities	98	99
Total	$ 506	$ 556

8. Fair Value Measurements

Derivatives — We enter into a variety of derivative instruments including both exchange traded and OTC power and natural gas forwards, options, instruments that settle on power price to natural gas price relationships (Heat Rate swaps) and interest rate swaps.

Our level 1 fair value derivative instruments primarily consist of natural gas futures and options traded on the NYMEX.

Our level 2 fair value derivative instruments primarily consist of our interest rate swaps and our OTC power and natural gas forwards where market data for pricing inputs is observable. Generally, we obtain our level 2 pricing inputs from markets such as the Intercontinental Exchange. 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 and time value, 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 SFAS No. 157 and include in level 3 all of those whose fair value is based on significant unobservable inputs.

The fair value of our derivatives includes consideration of the credit standing of the counterparties involved 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 management's best estimate.

Margin Deposits — Our margin deposits are cash and cash equivalents and are generally classified within level 1 of the fair value hierarchy as the amounts are valued using quoted market prices.

The following tables set forth below are by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2009, and December 31, 2008. As required by SFAS No. 157, 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.

	Recurring Fair Value Measures at Fair Value as of March 31, 2009			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Commodity derivatives	$ 4,106	$ 927	$ 183	$ 5,216
Interest rate derivatives	—	—	—	—
Total derivative assets	4,106	927	183	5,216
Cash equivalents(1)	1,963	—	—	1,963
Margin deposits(2)	382	—	—	382
Total	$ 6,451	$ 927	$ 183	$ 7,561
Liabilities:				
Commodity derivatives	$ 4,209	$ 480	$ 69	$ 4,758
Interest rate derivatives	—	444	—	444
Total derivative liabilities	4,209	924	69	5,202
Margin deposits held by us posted by our counterparties(2)	18	—	—	18
Total	$ 4,227	$ 924	$ 69	$ 5,220

	Recurring Fair Value Measures at Fair Value as of December 31, 2008			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Commodity derivatives	$ 3,263	$ 634	$ 160	$ 4,057
Interest rate derivatives	—	—	—	—
Total derivative assets	3,263	634	160	4,057
Cash equivalents(1)	2,092	—	—	2,092
Margin deposits(2)	653	—	—	653
Total	$ 6,008	$ 634	$ 160	$ 6,802
Liabilities:				
Commodity derivatives	$ 3,515	$ 475	$ 55	$ 4,045
Interest rate derivatives	—	452	—	452
Total derivative liabilities	3,515	927	55	4,497
Margin deposits held by us posted by our counterparties(2)	169	—	—	169
Total	$ 3,684	$ 927	$ 55	$ 4,666

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(1) Amounts represent cash equivalents invested in money market accounts and are included in cash and cash equivalents and restricted cash on our Consolidated Condensed Balance Sheets. As of March 31, 2009, and December 31, 2008, we had cash equivalents of $1,538 million and $1,597 million included in cash and cash equivalents and $425 million and $495 million included in restricted cash, respectively.

(2) Margin deposits and margin deposits held by us posted by our counterparties represent cash collateral paid between us and our counterparties to support our commodity contracts.

Gains or losses associated with level 3 balances may not necessarily reflect trends occurring in the underlying business. Further, unrealized gains and losses for the period from level 3 items are often offset by unrealized gains and losses on positions classified in level 1 or 2, as well as positions that have been realized during the quarter. Certain of our level 3 balances qualify for hedge accounting for which any unrealized gains and losses are recorded in OCI. Gains and losses for level 3 balances that do not qualify for hedge accounting are recorded in earnings.

The following table sets forth a reconciliation of changes in the fair value of our net derivatives classified as level 3 in the fair value hierarchy for the three months ended March 31, 2009 and 2008 (in millions):

	2009	2008
Balance, beginning of period	$ 105	$ (1)
Realized and unrealized gains (losses):		
Included in net income (loss)(1)	17	(191)
Included in OCI	18	(487)
Purchases, issuances and settlements, net	(13)	119
Transfers in and/or out of level 3(2)	(13)	—
Balance, end of period	$ 114	$ (560)
Change in unrealized gains relating to instruments still held as of March 31, 2009 and 2008(3)	$ 17	$ (155)

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(1) Includes $6 million and $(63) million recorded in operating revenues (for power contracts) and $11 million and $(128) million recorded in fuel and purchased energy expense (for natural gas contracts) as shown on our Consolidated Condensed Statement of Operations for the three months ended March 31, 2009 and 2008, respectively.

(2) We transfer amounts among levels of the fair value hierarchy as of the end of each period.

(3) Includes $6 million and $(69) million recorded in operating revenues (for power contracts) and $11 million and $(86) million recorded in fuel and purchased energy expense (for natural gas contracts) as shown on our Consolidated Condensed Statement of Operations for the three months ended March 31, 2009 and 2008, respectively.

9. Derivative Instruments and Collateral

The table below reflects the amounts that are recorded as derivative assets and liabilities on our Consolidated Condensed Balance Sheets at March 31, 2009, and December 31, 2008, for our derivative instruments (in millions):

	March 31, 2009		
	Interest Rate Swaps	Commodity Instruments	Total Derivative Instruments
Current derivative assets	$ —	$ 4,614	$ 4,614
Long-term derivative assets	—	602	602
Total derivative assets	$ —	$ 5,216	$ 5,216
Current derivative liabilities	$ 191	$ 4,245	$ 4,436
Long-term derivative liabilities	253	513	766
Total derivative liabilities	$ 444	$ 4,758	$ 5,202
Net derivative assets (liabilities)	$ (444)	$ 458	$ 14

	December 31, 2008		
	Interest Rate Swaps	Commodity Instruments	Total Derivative Instruments
Current derivative assets	$ —	$ 3,653	$ 3,653
Long-term derivative assets	—	404	404
Total derivative assets	$ —	$ 4,057	$ 4,057
Current derivative liabilities	$ 179	$ 3,620	$ 3,799
Long-term derivative liabilities	273	425	698
Total derivative liabilities	$ 452	$ 4,045	$ 4,497
Net derivative assets (liabilities)	$ (452)	$ 12	$ (440)

We adopted SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – An Amendment of FASB Statement No. 133" as of January 1, 2009. SFAS No. 161 requires enhanced disclosures about 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. SFAS No. 161 requires qualitative disclosures about our fair value amounts of gains and losses associated with derivative instruments, as well as disclosures about credit-risk-related contingent features in derivative agreements.

Commodity Instruments — We are susceptible to changes in prices for the purchase and sale of power, natural gas and other energy commodities. We utilize derivatives, which include physical commodity contracts and financial commodity instruments such as swaps and options and NYMEX contracts to attempt to maximize the risk-adjusted returns from our assets. These transactions primarily act as fair value and cash flow hedges. By entering into these transactions, we are able to economically hedge a portion of our spark spread at pre-determined generation and price levels.

Interest Rate Swaps — A significant portion of our debt is indexed to base rates, primarily LIBOR. We utilize 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. These transactions primarily act as cash flow hedges.

As of March 31, 2009, the maximum length of our PPAs extend until 24 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 4 and 17 years, respectively.

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 purchases or normal sales exemption. Revenues derived from these instruments that qualify for hedge accounting are recorded on a net basis in the period that the hedged item is recognized into earnings. 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 Condensed 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 and the associated gain or loss previously deferred in OCI is reclassified into current income. 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 no longer probable of occurring.

Fair Value Hedges — Changes in fair value of derivatives designated as fair value hedges and the corresponding changes in the fair value of the hedged risk attributable to a recognized asset or liability, or unrecognized firm commitment is recorded in earnings. If the fair value hedge is effective, the amounts recorded will offset in earnings. If the underlying asset, liability or firm commitment being hedged is disposed of or otherwise terminated, the gain or loss associated with the underlying hedged item is recognized currently in earnings. If the hedging instrument is terminated or de-designated prior to the settlement of the hedged asset, liability or firm commitment, the adjustment of the carrying amount of the hedged item would remain until the hedged item is recognized in earnings.

Derivatives Not Designated as Hedging Instruments — Along with our portfolio of hedging transactions, we enter into power and natural gas positions that often act as economic hedges to our asset portfolio, but either do not qualify as hedges under hedge accounting criteria guidelines or for which the hedge accounting designation has not been elected, such as commodity options transactions 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), fuel and purchased energy expense (for natural gas contracts) and interest expense (for interest rate swaps).

Derivatives Included on Our Consolidated Condensed Balance Sheet

The following table presents the fair values and locations of our net derivative instruments recorded in our Consolidated Condensed Balance Sheet at March 31, 2009 (in millions):

	At March 31, 2009	
	Fair Value of Derivative Assets(1)	**Fair Value of Derivative Liabilities(2)**
Derivatives designated as cash flow hedging instruments:		
Interest rate instruments	$ —	$ 422
Commodity instruments	748	207
Total derivatives designated as cash flow hedging instruments	$ 748	$ 629
Derivatives designated in fair value hedging relationships:		
Commodity instruments, hedging instrument	$ —	$ 49
Commodity instruments, hedged item	49	—
Total derivatives designated in fair value hedging relationships	$ 49	$ 49
Derivatives not designated as hedging instruments:		
Interest rate instruments	$ —	$ 22
Commodity instruments	4,419	4,502
Total derivatives not designated as hedging instruments	$ 4,419	$ 4,524
Total derivatives	$ 5,216	$ 5,202

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(1) Included in derivative assets on our Consolidated Condensed Balance Sheet.

(2) Included in derivative liabilities on our Consolidated Condensed Balance Sheet.

We execute forward physical and financial commodity purchase and sales agreements to hedge our exposure to underlying commodity risk. Through hedging and optimization activities it is not uncommon for us to purchase and sell forward natural gas and power in both the physical and financial markets. As of March 31, 2009, the net forward notional buy (sell) position of our outstanding commodity and interest rate swap contracts are as follows (in millions):

Derivative Instrument	Notional Volumes
Power (MWh)	(59)
Natural gas (MMBtu)	258
Interest rate swaps	$ 7,105

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 even allow our counterparty to request immediate, full settlement on certain derivative instruments in liability positions. We estimate that if our credit rating were downgraded and the credit-contingent provisions were triggered, we could be required to post additional collateral of approximately $1 million. The aggregate fair value of our derivative instruments in liability positions with credit-risk contingent provisions as of March 31, 2009, was $171 million for which we have posted collateral, margin or granted additional first priority liens on the assets currently subject to first priority liens under our Exit Credit Facility as collateral of $76 million.

Derivatives Included on Our Consolidated Condensed Statements of Operations, OCI and AOCI

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 Condensed Statements of Operations as a component of mark-to-market activity within our net income (loss).

The table below details the components of our total mark-to-market activity which includes the realized and unrealized gains (losses) recognized from our derivative instruments not designated as hedging instruments and ineffectiveness related to our hedging instruments and where they are recorded on our Consolidated Condensed Statements of Operations for the three months ended March 31, 2009 and 2008 (in millions):

	2009	2008
Power contracts included in operating revenues	$ 40	$ (96)
Natural gas contracts included in fuel and purchased energy expense	27	(55)
Interest rate swaps included in interest expense	(3)	(16)
Total mark-to-market activity	$ 64	$ (167)

The following table details the effect of our net derivative instruments that qualify for hedge accounting treatment on our Consolidated Condensed Statement of Operations, OCI and AOCI for the three months ended March 31, 2009 (in millions):

	Gain (Loss) Recognized in OCI (Effective Portion)	Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Gain (Loss) Reclassified from AOCI into Income (Ineffective Portion)
Interest rate instruments	$ 7	$ (44)[1]	$ —
Commodity instruments	128	111[2]	1[2][3]
Total	$ 135	$ 67	$ 1

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(1) Included in interest expense on our Consolidated Condensed Statement of Operations.

(2) Included in operating revenues and fuel and purchased energy expense on our Consolidated Condensed Statement of Operations.

(3) Ineffective portion of gains reclassified from AOCI into income on commodity hedging instruments were $6 million for the three months ended March 31, 2008.

We currently estimate that during the next 12 months, pre-tax, net gains of $256 million would be reclassified from AOCI into earnings at March 31, 2009 prices as the hedged transactions affect earnings assuming constant natural gas and power prices and interest rates over time; 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, management is unable to predict what the actual reclassification from AOCI to earnings (positive or negative) will be for the next 12 months.

The following table details the net unrealized gain from our net derivative instruments which do not qualify for hedge accounting treatment on our Consolidated Condensed Statement of Operations for the three months ended March 31, 2009 (in millions):

	Gain (Loss) in Income
Interest rate instruments[1]	$ 1
Commodity instruments[2]	125
Total	$ 126

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(1) Included in interest expense on our Consolidated Condensed Statement of Operations.

(2) Included in operating revenues and fuel and purchased energy expense on our Consolidated Condensed Statement of Operations.

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 the Exit Credit Facility as collateral under certain of our power and natural gas agreements that qualify as “eligible commodity hedge agreements” under the Exit Credit 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 the Exit Credit Facility. Such first priority liens had also been permitted under the DIP Facility prior to the conversion of the loans and commitments under the DIP Facility to our exit financing under the Exit Credit 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 March 31, 2009, and December 31, 2008 (in millions):

	March 31,2009	December 31, 2008
Margin deposits(4)	$ 382	$ 653
Natural gas and power prepayments	42	60
Total margin deposits and natural gas and power prepayments with our counterparties(1)	$ 424	$ 713
Letters of credit issued	$ 405	$ 455
First priority liens under power and natural gas agreements(2)	—	—
First priority liens under interest rate swap agreements	451	477
Total letters of credit and first priority liens with our counterparties	$ 856	$ 932
Margin deposits held by us posted by our counterparties(3)(4)	$ 18	$ 169
Letters of credit posted with us by our counterparties	260	95
Total margin deposits and letters of credit posted with us by our counterparties	$ 278	$ 264

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(1) At March 31, 2009, and December 31, 2008, $406 million and $693 million are included in margin deposits and other prepaid expense and $18 million and $20 million are included in other assets on our Consolidated Condensed Balance Sheets, respectively.

(2) At March 31, 2009, and December 31, 2008, the fair value of our energy commodities granted under first priority liens is an asset of $328 million and $201 million, respectively; therefore, there is no collateral exposure at March 31, 2009, or December 31, 2008.

(3) Included in other current liabilities on our Consolidated Condensed Balance Sheets.

(4) Balances are subject to master netting agreements but presented on gross basis on our Consolidated Condensed Balance Sheets.

Future collateral requirements for cash, first priority liens and letters of credit may increase based on the extent of our involvement in hedging and optimization contracts and movements in commodity prices, and also based on our credit ratings and general perception of creditworthiness in our market.

10. Earnings (Loss) per Share

Pursuant to the 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 unresolved as of the Effective Date, later become allowed. 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 the 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.

Reconciliations of the amounts used in the basic and diluted earnings (loss) per common share computations for the three months ending March 31, 2009 and 2008, are:

	2009	2008
	(shares in thousands)	
Diluted weighted average shares calculation:		
Weighted average shares outstanding (basic)	485,362	485,000
Restricted stock awards	233	—
Weighted average shares outstanding (diluted)	485,595	485,000

We excluded the following potentially dilutive securities from our calculation of diluted earnings (loss) per common share for the three months ended March 31, 2009 and 2008:

	2009	2008
	(shares in thousands)	
Employee stock options[(1)]	12,783	2,508
Restricted stock awards[(1)]	458	319
Common stock warrants[(1)(2)]	—	24,516

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(1) Excluded from diluted weighted average shares as these equity-based instruments are anti-dilutive in accordance with the calculation under the treasury stock method prescribed by SFAS No. 128, “Earnings per Share.”

(2) Pursuant to the 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.

11. 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. Under the MEIP and DEIP there are 14,833,000 shares and 167,000 shares, respectively, of our common stock authorized for issuance to participants. During the three months ended March 31, 2009, we issued 50,000 employee stock options as employment inducements under the MEIP. We granted a total of 2,732,852 shares of restricted common stock and 5,278,900 employee stock options under the MEIP and the DEIP during the three months ended March 31, 2008.

The equity awards granted under the Calpine Equity Incentive Plans 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. In addition, 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 a new Chief Executive Officer and a new Chief Legal Officer in August 2008, and a new Chief Commercial Officer in September 2008. No grants of options or shares of restricted stock were made outside of the Calpine Equity Incentive Plans during the three months ended March 31, 2009. Each of the employment inducement options vests over a period of five years, contains a contractual term of seven years and is subject to forfeiture under certain circumstances including termination of employment prior to vesting. Common stock for future stock option exercises will be issued from the MEIP share reserves or shares reserved for the employment inducement options issued outside of the MEIP.

We use the Black-Scholes option-pricing model to estimate the fair value of our employee stock options or its equivalent on the grant date, which takes into account the exercise price and expected life 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, 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. 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 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.

Stock-based compensation expense recognized was $13 million and $6 million for the three months ended March 31, 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 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 three months ended March 31, 2009 and 2008. At March 31, 2009, there was $50 million of unrecognized compensation cost related to equity awards, which is expected to be recognized over a weighted average period of 2.2 years for options and 1.2 years for restricted shares. We issue new shares from our reserves set aside for our MEIP, DEIP 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 MEIP and DEIP for the three months ended March 31, 2009, is as follows:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding – December 31, 2008	12,840,754	$ 19.72	7.5	$ —
Granted	50,000	$ 8.25		
Exercised	—	$ —		
Forfeited	111,242	$ 17.96		
Expired	64,100	$ 16.90		
Outstanding – March 31, 2009	12,715,412	$ 19.70	7.2	$ —
Exercisable – March 31, 2009	2,512,252	$ 17.33	8.5	$ —
Vested and expected to vest – March 31, 2009	12,459,540	$ 19.77	7.1	$ —

There were no employee stock options exercised during the three months ended March 31, 2009 and 2008.

The fair value of options granted during the three months ended March 31, 2009 and 2008, was determined on the grant date using the Black-Scholes pricing model. Certain assumptions were used in order to estimate fair value for options as noted in the following table.

	2009	2008
Expected term (in years)(1)	6.0	5.4 – 6.1
Risk-free interest rate(2)	2.3%	2.7 – 3.1%
Expected volatility(3)	73%	35.9 – 40.9%
Dividend yield(4)	—	—
Weighted average grant-date fair value (per option)	$ 5.40	$ 7.22

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(1) Expected term calculated using the simplified method under SAB 110 “Shared-Based Payment.”

(2) Zero Coupon U.S. Treasury rate or equivalent based on expected term.

(3) For the three months ended March 31, 2009, volatility calculated using the implied volatility of our exchange traded options. For the three months ended March 31, 2008, volatility calculated using the weighted average implied volatility of our industry peers’ exchange traded stock options.

(4) We are restricted from paying any cash dividends on our common stock for the foreseeable future under the Exit Credit Facility and certain of our other debt agreements. Future cash dividends, if any, will be at the discretion of our Board of Directors.

No restricted stock or restricted stock units have been granted other than under our MEIP and DEIP. A summary of our restricted stock and restricted stock unit activity for the MEIP and DEIP for the three months ended March 31, 2009, is as follows:

	Number of Restricted Stock Awards		Weighted Average Grant-Date Fair Value
Nonvested – December 31, 2008	1,742,242	$	16.69
Granted	—	$	—
Forfeited	64,178	$	16.92
Vested	774,804	$	16.67
Nonvested – March 31, 2009	903,260	$	16.68

The total fair value of our restricted stock and restricted stock units that vested during the three months ended March 31, 2009, was $6 million. No restricted stock or restricted stock units vested during the three months ended March 31, 2008.

12. Commitments and Contingencies

Global Financial Crisis — The deterioration of global economic conditions has constricted access to capital and credit markets in the U.S. and worldwide, including within our industry, for us and our counterparties. These conditions will likely continue during 2009 and possibly longer. However, we believe the combination of our cash on hand, cash flow generated from operations and availability under our existing credit facilities is sufficient to enable us to meet all of our obligations as they come due.

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 GAAP. Where we have determined an unfavorable outcome is probable and is reasonably estimable, we have accrued for potential litigation losses. During the pendency of our Chapter 11 cases through the Effective Date, pursuant to automatic stay provisions under the Bankruptcy Code and orders granted by the Canadian Court, all actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date as well as all pending litigation against the Calpine Debtors generally were stayed. 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. See Note 2 for information regarding our Chapter 11 cases and CCAA proceedings. In addition to the Chapter 11 cases and CCAA proceedings (in connection with which certain of the matters described below arose), and 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.

Hawaii Structural Ironworkers Pension Fund v. Calpine, et al. This case resides in the Santa Clara County Superior Court. Defendants in this case are Calpine Corporation, Peter Cartwright, Ann B. Curtis, John Wilson, Kenneth Derr, George Stathakis, Credit Suisse First Boston LLC, Banc of America Securities LLC, Deutsche Bank Securities, Inc. and Goldman Sachs & Co. The Hawaii Structural Ironworkers Pension Trust Fund alleges that the prospectus and registration statement for an April 2002 offering of Calpine Corporation securities contained false or misleading statements regarding: Calpine Corporation's actual financial results for 2000 and 2001; Calpine Corporation's projected financial results for 2002; Mr. Cartwright's alleged agreement not to sell or purchase shares within 90 days of the April 2002 offering; and Calpine Corporation's alleged involvement in "wash trades." The action was temporarily stayed during Calpine Corporation's Chapter 11 filing.

On December 19, 2007, Calpine Corporation entered into an agreement with the Hawaii Structural Ironworkers Pension Trust Fund to allow the action to proceed. Calpine Corporation remains a defendant to the action. The December 19, 2007, agreement provides that the Hawaii Structural Ironworkers Pension Fund waived its right to collect from Calpine Corporation on the claim it had filed against Calpine Corporation in the Chapter 11 cases, or for any settlement with Calpine Corporation, and agreed to seek recovery to satisfy its claim against Calpine Corporation, or for any settlement with Calpine Corporation, solely from any insurance coverage that may be available to Calpine Corporation. However, the December 19, 2007, agreement does not address the Hawaii Structural Ironworkers Pension Fund's claims against any of the other defendants. Some or all of the other defendants have asserted or may assert indemnification claims against Calpine Corporation in connection with this action.

On July 1, 2008, a second amended complaint was filed against the same defendants. The second amended complaint repeated the allegations from the first amended complaint and added allegations that the above-described prospectus and registration statement included false or misleading statements related, among other things, to Calpine Corporation's cash balances and cash flow, construction projects and asset sales. The parties completed fact discovery in February 2009 and are conducting expert discovery. No trial date has been set in this action. Mediation is being scheduled for Summer 2009. We continue to defend vigorously against the allegations.

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. Its 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.

The case was temporarily stayed during our Chapter 11 case; however, we and Pit River filed a stipulation to lift the automatic stay. On November 5, 2006, 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 U.S. District Court ruled that the lease extension for the two Fourmile Hill leases and the approval to construct a proposed 49.9 MW Fourmile Hill power plant should be remanded to the federal agencies for curative action. The U.S. District Court also required that we notify BLM and U.S. Forest Service that we affirm the original plan of utilization for 49.9 MW Fourmile Hill power project by April 1, 2009, or to submit a new plan of utilization for review by a date to be set by the agencies. On March 31, 2009, in compliance with the Court's December 22, 2008, order, we informed the BLM that we did not want the BLM to perform the curative actions in its environmental impact assessment and other procedural steps based upon the previously proposed 49.9 MW Fourmile Hill power project. Instead, we would likely construct a larger project to be located on both the Fourmile Hill leases and the Telephone Flat leases. We requested the federal agencies prepare a programmatic environmental impact statement for the Medicine Lake and Glass Mountain geothermal areas and determine whether and how geothermal exploration and development should occur in those areas based upon a reasonable foreseeable development scenario which assumes the BLM's previously published resource potential of 480 MW.

In addition, Pit River and other interested parties filed two separate suits in the U.S. District Court for the Eastern District of California seeking to enjoin exploration, construction, and development of the Telephone Flat leases and proposed project at Glass Mountain in May 2004. These two related cases continue to be subject to the discharge injunction as described in the Order confirming the Plan of Reorganization. Similar to above, we are now in communication with the U.S. Department of Justice regarding these two cases; but, the cases remain mostly inactive pending the outcome of the above described Pit Tribe case.

Appeal of Confirmation Order. Several parties filed appeals in the SDNY Court seeking reconsideration of the Confirmation Order of the U.S. Bankruptcy Court, despite the effectiveness of the Plan of Reorganization. On February 25, March 10, and March 14, 2008, the shareholder appellants filed their respective opening briefs. Calpine filed a response on March 28, 2008, seeking to dismiss the appeals on grounds that (i) the appeals were equitably moot, (ii) the appellants had not made the threshold showing required to reverse the U.S. Bankruptcy Court; and (iii) the appeals all lack merit. The appellants filed their reply briefs on April 7, 2008. On June 6, 2008, the SDNY Court entered an order denying the appeals, finding that all of the appeals were equitably moot. One of the shareholders (Mr. Felluss) filed a motion for reconsideration, which was denied on June 24, 2008. On July 3, 2008, Mr. Felluss filed a notice of appeal with the Second Circuit. On

August 8, 2008, Mr. Felluss filed a motion with the Second Circuit seeking to stay the expiration of the warrants that had been issued pursuant to the Plan of Reorganization and were scheduled to expire August 25, 2008; the Second Circuit denied the motion on August 27, 2008. The parties then proceeded to brief the merits of Mr. Felluss' appeal. Mr. Felluss filed his opening brief on September 5, 2008; we filed a response brief on October 6, 2008; and Mr. Felluss filed his reply on October 20, 2008. Rather than scheduling argument, on November 4, 2008, the Second Circuit asked whether the appeal could be decided on the written briefs without argument. Mr. Felluss has requested oral argument if it would be useful to the Court. We and the Official Committee of Unsecured Creditors both notified the Court that, in our view, the appeal could be decided on the written briefs, without oral argument, but sought to participate at argument if granted to Mr. Felluss. We are waiting for the Second Circuit either to schedule oral argument or to issue its decision.

Other Contingencies

Texas City and Clear Lake Environmental Matters. As part of an internal review of our Texas City and Clear Lake Cogeneration power plants, we determined that our Acid Rain Program exemption under 40 CFR 72.6(b)(5) had ceased to apply and we were in violation of the requirements of the Acid Rain Program found in 40 CFR Parts 72-78. We were originally exempt from these provisions based upon each plant being a qualifying cogeneration power plant in operation before November 1990 with qualifying PPAs; however, the exemptions ceased to apply in 2002 for Texas City and 1999 for Clear Lake. To remedy the violation, we are required to report our SO_2 emissions to the EPA and purchase allowances and remit an excess emission fee for each ton over the allowance emitted since expiration of the exemption. We recorded estimated fees of $300,000 for Texas City and Clear Lake Cogeneration power plants. We self-reported these violations to the TCEQ and the EPA and we are working with these agencies to resolve these matters in a timely manner. Although these agencies have the authority and discretion to issue substantial fines that could be material, we do not believe that the penalties, if any, resulting from these matters will have a material adverse effect on our business, financial condition or results of operations based upon our analysis of the facts and circumstances and consideration of recent cases addressed by the agencies involved.

Lyondell Bankruptcy. On January 6, 2009, Lyondell Chemical Co. and certain of its subsidiaries, including Houston Refining LP, filed for protection under Chapter 11 in the U.S. Bankruptcy Court. Channel Energy Center leases its project site from Houston Refining LP and is granted certain easements in, over, under and on the site pursuant to the lease. Channel Energy Center provides power and steam to Houston Refining LP pursuant to a power services agreement and, pursuant to a power plant services agreement, provides clarified water and treated water to Houston Refining LP. Channel Energy Center is provided with raw water, refinery gas and certain other power plant services by Houston Refining LP.

Although we do not consider it likely, the Lyondell debtors may exercise their right under the Bankruptcy Code to reject the lease, the power services agreement and/or the power plant services agreement. The potential damages to us if any or all of these agreements is rejected are uncertain. To the extent that any such damages would be recoverable under the laws of the State of Texas, the governing law under the agreements, they would be treated as an unsecured claim against the Lyondell debtors in bankruptcy.

We continue to monitor this matter closely and will seek vigorously to protect our rights under our various agreements with the Lyondell debtors.

13. Segment Information

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 assess our business primarily 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. Accordingly, our reportable segments are West (including geothermal), Texas, Southeast and North (including Canada).

Commodity Margin includes our power and steam revenues, REC revenue, transmission revenue and expenses, fuel and purchased energy expense, 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 revenue. Commodity Margin is a key operational measure reviewed by our chief operating decision maker to assess the performance of our segments.

During the first quarter of 2009, we began assessing the performance of our regional segments including the allocation of revenues and expenses from our fuel management, TMG, certain non-region specific natural gas marketing and optimization and other corporate activities that were formerly non-allocated and previously reported as our "Other" segment to our operating segments based upon MWh generated. Additionally, we have modified our definition of Commodity Margin to include cash settlements from our marketing, hedging and optimization activities that were previously included in mark-to-market activity. Our 2008 segment information has been reclassified to conform to the current year presentation. Financial data for our segments were as follows (in millions):

	Three Months Ended March 31, 2009					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Revenues from external customers	$ 888	$ 485	$ 173	$ 131	$ —	$ 1,677
Intersegment revenues	8	33	34	11	(86)	—
Total revenue	$ 896	$ 518	$ 207	$ 142	$ (86)	$ 1,677
Commodity Margin	297	122	61	49	—	529
Add: Mark-to-market commodity activity, net and other revenue(1)	22	90	31	4	(14)	133
Less:						
Plant operating expense	127	78	32	20	(9)	248
Depreciation and amortization expense	49	30	16	16	(2)	109
Other cost of revenue	15	3	3	8	(6)	23
Gross profit	128	101	41	9	3	282
Other operating expense						31
Income from operations						251
Interest expense, net of interest income						204
Other (income) expense, net						4
Income before reorganization items and income taxes						43
Reorganization items						3
Income before income taxes						$ 40

	Three Months Ended March 31, 2008					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Revenues from external customers	$ 972	$ 575	$ 262	$ 142	$ —	$ 1,951
Intersegment revenues	10	41	34	5	(90)	—
Total revenue	$ 982	$ 616	$ 296	$ 147	$ (90)	$ 1,951
Commodity Margin	278	139	35	61	—	513
Add: Mark-to-market commodity activity, net and other revenue(1)	(49)	(125)	(13)	23	(3)	(167)
Less:						
Plant operating expense	112	70	30	26	(6)	232
Depreciation and amortization expense	51	30	19	12	(1)	111
Other cost of revenue	17	—	9	6	—	32
Gross profit (loss)	49	(86)	(36)	40	4	(29)
Other operating expense						53
Loss from operations						(82)
Interest expense, net of interest income						406
Other (income) expense, net						10
Loss before reorganization items and income taxes						(498)
Reorganization items						(279)
Loss before income taxes						$ (219)

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(1) Mark-to-market commodity activity represents the unrealized portion of our mark-to-market activity, net, as well as a non-cash gain from amortization of prepaid power sales agreements included in operating revenues and fuel and purchased energy expense on our Consolidated Condensed Statements of Operations.

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

Introduction and Overview

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 the major competitive power markets in the U.S., including California and Texas. We sell wholesale power, steam, 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 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, commodity and financial derivative transactions to hedge our business risks and optimize our portfolio of power plants. We seek to grow our business through selective power plant development, construction and acquisition as well as through expansion or upgrades of our existing power plants, in each case, based primarily on whether we expect to achieve an attractive return on invested capital.

We are the largest publicly traded, independent wholesale power company in the U.S. measured by power produced in the U.S. in 2008. Our portfolio, including partnership interests, consists of 76 operating power plants, with an aggregate generation capacity of approximately 24,187 MW and our net interest in two additional power plants totaling nearly 1,000 MW under construction or in advanced development. Our portfolio is comprised of two types of power generation technologies: natural gas-fired combustion turbines (primarily combined-cycle) and renewable geothermal conventional steam turbines. We generate 4,080 MW of baseload capacity from our Geysers Assets and cogeneration power plants (natural gas-fired power plants that produce and sell both power and steam), 15,057 MW of intermediate load capacity from our combined-cycle combustion turbines and 5,050 MW of peaking capacity from our simple-cycle combustion turbines and duct-fired capability.

We assess our business primarily 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, Southeast and North (including Canada). In these segments we have 7,487 MW of capacity in Texas, 7,246 MW in the West, 6,104 MW in the Southeast and 3,350 MW in the North (including Canada). Our Geysers Assets, located in northern California and included in our West segment, produce approximately 725 MW from 15 operating power plants and represent the largest geothermal power generation portfolio in the U.S.

We remain focused on increasing our earnings and generating cash flows sufficient to maintain adequate levels of liquidity to service our debt and to fund our operations. 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.

Legislative and Regulatory Update

Ongoing state, regional and federal initiatives to implement new environmental and other governmental regulations are expected to have a significant impact on the power generation industry. We are actively participating in these debates at the federal, regional and state levels concerning potential environmental regulation. Although the ultimate legislation and regulations that result from these activities could have a material impact on our business, we believe we will face an overall lower compliance burden than some of our competitors due to the relatively low GHG emission rates of our fleet. For a further discussion of the environmental and other governmental regulations that affect us, please see "— Governmental and Regulatory Matters" in Part I, Item 1. of our 2008 Form 10-K. Below is a short discussion of the recent developments as they pertain to our business.

Climate Change

On March 31, 2009, a climate change and clean energy legislative discussion draft, "The American Clean Energy and Security Act of 2009" was proposed by the chairmen of both the House Energy Committee and the House Energy and Environment Subcommittee. The discussion draft proposes, among other things:

- an economy-wide carbon cap-and-trade program,
- setting carbon emissions reduction targets of: 3% from 2005 levels by 2012, 20% by 2020, 42% by 2030, and 83% by 2050,
- a federal renewable electricity standard which requires retail electricity suppliers to supply a specific percentage of power from renewable energy resources,
- federal policy objectives for transmission planning to facilitate deployment of renewable and zero-carbon electricity resources while ensuring reliability, congestion reduction, cyber-security, and cost-effective electricity services,
- delegating to FERC responsibility for regulation of the cash market in emission allowances and offsets and directing the President to delegate the regulatory responsibility for the derivatives market to an appropriate agency (or agencies).

Further details, including disbursement of allowances and proceeds from allowance auctions, are expected to evolve through committee member discussions, legislative hearings and the markup process. The proposal currently does not address whether long-term contracts that were executed before the regulation of GHG emissions were reasonably anticipated, would be eligible for free allowances or otherwise excepted under the regulation. We have certain power and steam sales contracts that may not allow such costs to be recovered from customers, which could raise our costs of compliance or offset potential benefits to us.

Hearings on the discussion draft have been held and we expect debate to continue. The Senate has not yet taken any action on climate change legislation. Although we cannot predict the ultimate effect any future climate change legislation or regulations could have on our business, we intend to monitor the process and may seek to be heard on any legislation that may ultimately be proposed.

Texas Legislation

Proposed Texas bill HB 2782, currently pending in the House State Affairs Committee, would limit the amount of generation a single entity is permitted to own or control in ERCOT, in an ERCOT zonal boundary or in a functional market recognized by the PUCT to 20%. If an entity owns or controls more than 20% in any such area, that entity would be required to sell at auction or otherwise divest that amount of generation needed to bring it below the 20% threshold, with the PUCT to be required to adopt rules no later than December 31, 2009, to define the scope of the auctions if the bill becomes law. The Senate bill counterpart has not yet been heard in committee. We currently own more than 20% of the generation in the Houston zone; however, we cannot predict at this time whether this or similar legislation will be passed, or what impact it will have on us if passed. We intend to monitor the process and may seek to be heard on any such legislation if it proceeds.

Federal Regulation of GHG under Existing Law

As discussed in the 2008 Form 10-K, in 2007 the U.S. Supreme Court ruled in *Commonwealth of Massachusetts, et al. v. U.S. Environmental Protection Agency*, that the EPA has the authority to regulate GHG issues under language included in the CAA. On April 24, 2009, the EPA released its proposed finding that GHG emissions endanger the public health and welfare of current and future generations. Should the EPA finalize the finding, it may begin developing rules to regulate GHG emissions under the CAA. We are uncertain of the timing of the process for development of potential GHG emissions regulations or what form such regulations may take; accordingly, it is not clear what impact any regulations will have on us.

Stimulus Bill

The American Recovery and Reinvestment Act of 2009, also referred to as the Stimulus Bill, was signed into law on February 17, 2009. The Stimulus Bill is intended to spur economic activity and growth in the wake of the recent economic downturn. The Stimulus Bill includes approximately $787.0 billion in federal tax cuts, expansion of unemployment benefits and other social welfare provisions, increased domestic spending for education, healthcare and infrastructure, including the energy sector. The Stimulus Bill includes approximately $43.0 billion devoted to renewable energy for loans and investments into green energy technology and a number of other incentives that can impact our growth and development, particularly of our geothermal assets. Specifically, the Stimulus Bill:

- extends the deadline to place new geothermal projects in service to qualify for ten years of “production tax credits” on the electricity output by three years through 2013
- provides geothermal developers the option to elect a 30% investment tax credit in lieu of production tax credits with respect to certain “qualified property” that is part of a geothermal plant placed in service during 2009 or 2010 (or, in certain cases, after 2010), with the ability to receive that 30% investment tax credit in the form of a cash grant from the Department of Treasury that, subject to yet-to-be issued rules, would be paid within 60 days following the later of (i) the placed-in-service date of the new facility and (ii) the grant application date
- designates $6.0 billion in funds to be used as a loss reserve and source of funding for a federal loan guarantee program, anticipated to backstop $80.0 to $110.0 billion of financing for new renewable energy plant and transmission line projects
- designates $400 million in funds for the Department of Energy’s Geothermal Technologies Program, which we anticipate will be utilized for cost shared drilling with industry and research and development projects, both targeted towards advancing the production of geothermal energy

We anticipate that our planned investment in our current geothermal power plants, including the re-powering of many of our existing power plants, along with expansion efforts that may include new geothermal plant development, could all benefit from the additional funds and incentives provided by the Stimulus Bill.

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.

Volatility in the financial markets through 2008 and into 2009, including the failure or merger of certain financial institutions and continued uncertainty surrounding many others continues to constrict access to capital and credit markets in the U.S. and worldwide, including within our industry, for us and for our counterparties. We expect these conditions will persist during 2009 and possibly longer. As a result, we and the industry have experienced increased credit and liquidity risk over the past several months. Even if we are not impacted directly, we could be impacted indirectly in the event our counterparties are unable to perform under their contractual obligations with us. We actively monitor our exposure to our counterparties including their credit status.

As of March 31, 2009, we had $1.6 billion in cash and cash equivalents and $476 million of restricted cash including $725 million borrowed on October 2, 2008, under our Exit Credit Facility revolving facility. This borrowing, which was invested in money market funds, which are mainly invested in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. government, its agencies or instrumentalities, was a proactive financial decision to increase our cash position and reduce the risk of nonperformance from institutions that hold a commitment in our Exit Credit Facility revolving facility during a period of uncertainty in the capital markets. Our remaining availability under our Exit Credit Facility revolving facility as of March 31, 2009, is approximately $45 million for future letters of credit or cash borrowings. Our decision to repay, hold or pay down other debt with the cash from our $725 million draw under our Exit Credit Facility revolving facility will be determined based upon our future liquidity needs and confidence in future credit markets.

We have $740 million in current maturities of long-term debt as of March 31, 2009. We believe that we have adequate resources to repay our current maturities as they become due with a combination of cash and cash equivalents on hand and cash expected to be generated from future operations. In the event confidence in the credit markets returns and if we are able to obtain favorable credit terms, we may decide to refinance portions of our current maturities or other more costly debt.

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 May 5, 2009, an increase of $1/MMBtu in natural gas prices would result in an increase of collateral required of approximately $205 million. If natural gas prices decreased by $1/MMBtu, we estimate that our collateral requirements would decrease by approximately $210 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. Based upon historical relationships of natural gas and Market Heat Rate movements for our portfolio of assets, we derived a statistical analysis that indicates that a change of $1/MMBtu in natural gas is comparable to a Market Heat Rate change of 170 Btu/KWh. We estimate that, as of May 5, 2009, an increase of 170 Btu/KWh in the Market Heat Rate would result in an increase in collateral required of approximately $21 million. If Market Heat Rates were to fall at a similar rate, we estimate that our collateral required would decrease by $22 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 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 the Exit Credit Facility to collateralize our obligations under certain of our power and natural gas agreements that qualify as "eligible commodity hedge agreements" under the Exit Credit 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 the Exit Credit Facility. See Note 9 of the Notes to Consolidated Condensed Financial Statements for further information on our margin deposits and collateral used for commodity procurement and risk management activities.

To provide for increased liquidity in periods of rising commodity prices, we entered into two credit facilities, the Knock-in Facility and Commodity Collateral Revolver that increase our liquidity available to collateralize obligations to counterparties under eligible commodity hedge agreements during periods of increasing natural gas prices. The Knock-in Facility, maturing on June 25, 2009, provides an initial $50 million of available capacity for the issuance of letters of credit up to a total maximum availability of $200 million contingent on natural gas futures contract prices exceeding certain thresholds. The Commodity Collateral Revolver, maturing July 8, 2010, under which we received an initial advance of $100 million, provides up to a total maximum availability of $300 million contingent on mark-to-market exposure amounts under certain reference transactions. It is unlikely that any additional amounts under either facility will be available as natural gas prices are not expected to exceed stated thresholds in the near future.

We could potentially face downward pressure on our Commodity Margin as a result of the current economic recession. The impacts would be highly dependent on the severity and duration of the economic downturn. During pronounced recessionary periods, there can be a decrease in power demand primarily driven by decreased usage by the industrial and manufacturing sectors. This "softening" of demand typically results in more demand satisfied by baseload and intermediate units using lower variable cost fuel sources such as coal and nuclear fuel, and less demand served by higher variable cost units such as natural gas-fired peaking power plants. Additionally, a recessionary environment can result in lower natural gas pricing which may adversely impact our Commodity Margin as our cost of production advantage relative to less efficient natural gas-fired generation is diminished on an absolute basis. However, with our combined forward power sales and natural gas purchases, we believe that we have substantially hedged our Commodity Margin for the remainder of 2009. Additionally, we have continued to increase our hedging activities through 2010 and therefore do not expect further declines in natural gas prices to significantly impact our results of operations in the near term.

It is difficult to predict future developments and the amount of credit support that we may need to provide as part of our business operations should financial market and commodity price volatility persist for a significant period of time. Our ability to generate sufficient cash is dependent upon, among other things: (i) improving the profitability of our operations; (ii) continued compliance with the covenants under our Exit Credit Facility and other existing financing obligations; (iii) stabilizing and increasing future contractual cash flows; and (iv) our significant counterparties performing under their contracts with us.

Despite the current volatility in the financial markets and the relative illiquidity in the credit markets, we concluded a significant financing transaction in January 2009. 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 at Deer Park's option of LIBOR plus 3.5% or base rate plus 2.5%.

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

	2009
Exit Credit Facility	$ 230
Calpine Development Holdings, Inc.	148
Knock-in Facility	30
Various project financing facilities	98
Total	$ 506

Cash Management — We manage our cash in accordance with our intercompany cash management system subject to the requirements of the Exit Credit 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 are prohibited from paying any cash dividends on our common stock for the foreseeable future because our ability to pay cash dividends is restricted under the Exit Credit Facility and certain of our other debt agreements. Future cash dividends, if any, will be at the discretion of our Board of Directors and will depend upon, among other things, our future operations and earnings, capital requirements, general financial condition, contractual and financing restrictions and such other factors as our Board of Directors may deem relevant.

NOLs — We have significant NOLs that will provide future tax deductions if we generate sufficient taxable income during the carryover periods. We are comprised primarily of two groups for federal income tax reporting purposes, 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, 2008, our consolidated federal NOLs totaled approximately $7.5 billion, which consists of approximately $7.1 billion from our Calpine group and approximately $396 million from our CCFC group. We expect to generate approximately $150 million to $200 million in federal NOLs in 2009 from the CCFC and Calpine groups. In addition, we have approximately $1.0 billion in foreign NOLs and $4.4 billion in state NOLs. Our Calpine group has recorded a valuation allowance against the deferred taxes related to most of their NOLs as we determined it is more likely than not, that they will expire unutilized. We estimate that our CCFC group will be able to utilize their NOLs, and accordingly have not recorded a valuation allowance against the deferred taxes related to these NOLs. Approximately $5.6 billion of our NOLs have annual limitations under Section 382 of the IRC. Amounts subject to limitations, but not used, can be carried forward to succeeding years.

Optimization of Existing Assets — We continue to review development opportunities, which were put on hold during the pendency of our Chapter 11 cases, to determine whether future actions are appropriate and we may pursue new opportunities that arise, particularly if power contracts and financing are available and attractive returns are expected. Currently, we have one project, Russell City Energy Center, in advanced development and our OMEC project remains under construction and is expected to achieve commercial operations in the fall of 2009.

The Russell City Energy Center is currently contracted to deliver its full output to PG&E under a PPA which was executed in December 2006 and approved by the CPUC in January 2007. The PPA was amended in 2008 and was approved by the CPUC on April 16, 2009. All permits for the projects have been issued and approved with the exception of an air permit now pending before the local air quality board. Under the amended PPA, the expected commercial operation date has been extended by two years from 2010 to June 2012. Completion of the Russell City Energy Center is dependent upon obtaining the necessary permits, regulatory approvals, construction contracts and construction funding under project financing facilities. We do not expect the costs to complete the Russell City Energy Center to be material to us on a consolidated basis. Upon completion, this project would bring on line approximately 362 MW of net interest baseload capacity (390 MW with peaking capacity) representing our 65% share.

We hold all of the equity interest in one unconsolidated project under construction at March 31, 2009, OMEC, which is expected to achieve commercial operations in 2009. The completion of OMEC will bring on line approximately 596 MW of net interest baseload (with peaking) capacity. We also own a 50% equity interest in the Greenfield Energy Centre, which achieved commercial operations on October 17, 2008. Our net interest baseload (with peaking) capacity increased as a result of Greenfield Energy Centre by approximately 503 MW representing our 50% share.

Cash Flow Activities — The following table summarizes our cash flow activities for the three months ended March 31, 2009 and 2008 (in millions):

	2009	2008
Beginning cash and cash equivalents	$ 1,657	$ 1,915
Net cash provided by (used in):		
Operating activities	80	(340)
Investing activities	(27)	483
Financing activities	(84)	(1,777)
Net decrease in cash and cash equivalents	(31)	(1,634)
Ending cash and cash equivalents	$ 1,626	$ 281

Net Cash Provided By (Used In) Operating Activities

Cash flows provided by operating activities for the three months ended March 31, 2009, resulted in net inflows of $80 million compared to outflows of $340 million for the same period in 2008. The change in cash flows from operating activities was primarily due to:

- Increases in gross profit — Gross profit, excluding unrealized changes in mark-to-market activity, increased by $7 million in 2009 primarily due to higher realized spark spreads resulting from higher hedged levels. The favorable margins were partially offset by a decrease in generation.
- Decreases in interest paid — Cash paid for interest decreased by $244 million in 2009 to $226 million for the three months ended March 31, 2009, as compared to $470 million for the same period in 2008, primarily due to the repayment of the Second Priority Debt.
- Decreases in working capital — Working capital employed decreased by approximately $91 million during the period after adjusting for debt related balances and assets held for sale, which did not impact cash provided by operating activities. The decrease was primarily due to reductions in margin deposits partially offset by current derivative activity.
- Decreases in reorganization costs — Cash payments for reorganization items decreased by $64 million.

Net Cash Provided By (Used In) Investing Activities

Cash flows used in investing activities for the three months ended March 31, 2009, were $27 million compared to cash flows provided by investing activities of $483 million for the three months ended March 31, 2008. The difference was primarily due to:

- Sales of power plants, turbines and investments — Proceeds from asset sales were $398 million in 2008 compared to nil in 2009.
- Reconsolidation of our Canadian Debtors and other foreign entities — In 2008, a favorable cash effect of $64 million was received from the reconsolidation of our Canadian Debtors and other foreign entities.
- Return of investment from unconsolidated investments — In the three months ended March 31, 2008, we received distributions of $24 million compared to nil for the three months ended March 31, 2009.
- Reduced restricted cash requirements — The net reduction in restricted cash was $27 million in 2009, down $16 million from $43 million in 2008. Restricted cash decreased in 2009 mainly due to regularly scheduled repayments of notes payable partially offset by funding from the Deer Park financing.

Net Cash Used In Financing Activities

Cash flows used in financing activities for the three months ended March 31, 2009, resulted in outflows of $84 million compared to outflows of $1,777 million for the same period in 2008. Because of our emergence from Chapter 11 during the first quarter of 2008, our financing activities are not comparable. Our significant 2009 and 2008 financing transactions are described below:

- During the first quarter of 2009, we received net proceeds of $64 million from the refinancing of Deer Park and made scheduled debt and capital lease repayments of $141 million.
- During the first quarter of 2008, we borrowed approximately $2.7 billion under the Exit Facilities and used the borrowing together with cash on hand to repay approximately $3.7 billion of the Second Priority Debt and $98 million of DIP Facility debt. We repaid the $300 million Bridge Facility with proceeds from the sale of certain power plant assets, made repayments of $155 million on our senior secured revolving facility under the Exit Credit Facility and made repayments of $189 million on other debt and capital lease obligations. In addition, we received proceeds of $90 million from the Blue Spruce refinancing, which was used to repay the outstanding $56 million debt obligation that is included in the above $189 million repayment, and incurred cash financing costs of $175 million primarily related to the Exit Facilities.

Special Purpose Subsidiaries — Pursuant to applicable transaction agreements, we have established certain of our entities separate from Calpine and our other subsidiaries. In accordance with applicable accounting standards, we consolidate these entities. As of the date of filing this Report, these entities included: Rocky Mountain Energy Center, LLC, Riverside Energy Center, LLC, Calpine Riverside Holdings, LLC, PCF, PCF III, GEC Holdings, LLC, Gilroy Energy Center, LLC, Creed Energy Center, LLC, Goose Haven Energy Center, LLC, 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.), CCFC Preferred Holdings, LLC, and Russell City Energy Company, LLC.

Results of Operations for the Three Months Ended March 31, 2009 and 2008

Below are the results of operations for the three months ended March 31, 2009, as compared to the same period in 2008 (in millions, except for percentages and operating performance metrics). We have modified our presentation of commodity revenue and commodity expense to include cash settlements from our marketing, hedging and optimization activities that were previously included in mark-to-market activity. Our 2008 commodity revenue and expense information has been reclassified to conform to the current year presentation. In the "$ Change" and ''% Change" columns 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	$ 1,582	$ 2,116	$ (534)	(25)%
Mark-to-market activity(1)	87	(176)	263	#
Other revenue	8	11	(3)	(27)
Operating revenues	1,677	1,951	(274)	(14)
Cost of revenue:				
Fuel and purchased energy expense:				
Commodity expense	1,053	1,603	550	34
Mark-to-market activity(1)	(38)	2	40	#
Fuel and purchased energy expense	1,015	1,605	590	37
Plant operating expense	248	232	(16)	(7)
Depreciation and amortization expense	109	111	2	2
Other cost of revenue	23	32	9	28
Total cost of revenue	1,395	1,980	585	30
Gross profit (loss)	282	(29)	311	#
Sales, general and other administrative expense	45	48	3	6
(Income) loss from unconsolidated investments in power plants	(17)	3	20	#
Other operating expense	3	2	(1)	(50)
Income (loss) from operations	251	(82)	333	#
Interest expense	210	419	209	50
Interest (income)	(6)	(13)	(7)	(54)
Other (income) expense, net	4	10	6	60
Income (loss) before reorganization items and income taxes	43	(498)	541	#
Reorganization items	3	(279)	(282)	#
Income (loss) before income taxes	40	(219)	259	#
Income tax expense (benefit)	9	(5)	(14)	#
Net income (loss)	31	(214)	245	#
Add: Net loss attributable to the noncontrolling interest	1	—	1	—
Net income (loss) attributable to Calpine	$ 32	$ (214)	$ 246	#
Operating Performance Metrics:				
MWh generated (in thousands)(2)	19,267	20,906	(1,639)	(8)
Average availability	90.9%	85.8%	5.1	6
Average total MW in operation	23,423	23,113	310	1
Average capacity factor, excluding peakers	43.2%	46.2%	(3.0)	(6)
Steam Adjusted Heat Rate	7,188	7,161	(27)	—

\# 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) Represents generation from power plants that we both consolidate and operate.

Commodity revenue, net of commodity expense, increased $16 million for the three months ended March 31, 2009, compared to the same period in 2008 primarily due to: (i) higher hedge prices and higher hedge levels in the first quarter of 2009, particularly in the West and Southeast, despite lower market spark spreads driven by lower natural gas prices during the same period; (ii) an increase from the sale of surplus emission allowances in the West; (iii) higher Market Heat Rates in the Southeast attributable in part to gas generation displacement of coal generation in certain markets; and (iv) the beneficial impact in the first quarter of 2009 of advantageous transmission, customer and transportation agreements on some of our plants in the Southeast. This overall increase was partially offset by an 8% decrease in generation, despite a 6% increase in our average availability, primarily due to lower market spark spreads in the West and Texas. Net unrealized mark-to-market activity primarily resulting from our portfolio hedging activities that do not qualify for hedge accounting increased $303 million for the three months ended March 31, 2009, compared to the same period in 2008.

Plant operating expense increased $16 million during the three months ended March 31, 2009, compared to the three months ended March 31, 2008, primarily due to an $8 million increase in major maintenance resulting from our outage schedule as well as a $3 million increase in stock compensation expense related to plant personnel costs. Normal, recurring costs in plant operating expense were generally comparable in the first quarter of 2009 compared to the first quarter of 2008.

Other cost of revenue decreased for the three months ended March 31, 2009, compared to the three months ended March 31, 2008, as a result of a decrease of $7 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 a $3 million decrease in royalty expense due to lower revenues from our Geysers Assets resulting from lower power prices in the first quarter of 2009 compared to 2008.

Our income from unconsolidated investments in power plants was $17 million for the three months ended March 31, 2009, compared to a loss from unconsolidated investments in power plants of $3 million for the three months ended March 31, 2008. The increase is primarily the result of unrealized mark-to-market gains of $10 million from an interest rate swap contract on OMEC. In addition, our investment in Greenfield LP contributed income of $5 million for the three months ended March 31, 2009, compared to a loss of $6 million for the three months ended March 31, 2008.

Due to the changes in our capital structure on the Effective Date, our interest expense for three months ended March 31, 2009 and 2008, is not 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. In addition, interest expense decreased for the three months ended March 31, 2009, compared to the three months ended March 31, 2008, due to lower average debt balances and lower average interest rates. During the first quarter of 2008, we settled a portion of our debt through payment of cash and issuance of common stock pursuant to the Plan of Reorganization. Additionally, interest rates on our variable rate debt were lower for the three months ended March 31, 2009, compared to 2008, due to a decrease in LIBOR over the same periods. The annualized effective interest rates on our consolidated debt, excluding the impacts of items not directly attributed to the cost of the debt instruments, after amortization of deferred financing costs and debt discounts, were 8.1% and 9.2%, respectively, for the three months ended March 31, 2009 and 2008. The decrease was partially offset by an unfavorable change of $40 million related to our interest rate swaps on our Exit Credit Facility for the three months ended March 31, 2009, compared to 2008 as well as $27 million for settlement obligations related to our Canadian Debtors and other foreign entities recorded prior to their reconsolidation in February 2008.

Interest income decreased primarily due to lower average cash balances for the three months ended March 31, 2009, compared to the same period in 2008 resulting from the distribution of cash pursuant to the Plan of Reorganization in the first quarter of 2008, and due to lower average interest rates.

Other (income) expense, net decreased primarily due to $7 million in refinancing costs related to the refinancing of all outstanding indebtedness under the existing Blue Spruce term loan facility for the three months ended March 31, 2008.

During the three months ended March 31, 2008, reorganization items primarily consisted of gains on asset sales as well as a gain on the reconsolidation of our Canadian Debtors and other foreign entities.

For the three months ended March 31, 2009, we recorded income tax expense of $9 million compared to an income tax benefit of $5 million for the three months ended March 31, 2008. See Note 1 of the Notes to Consolidated Condensed Financial Statements for further information.

Commodity Margin and Adjusted EBITDA

Management's Discussion and Analysis of Financial Condition and Results of Operations includes financial information prepared in accordance with 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 GAAP.

Commodity Margin by Segment for the Three Months Ended March 31, 2009 and 2008

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, REC revenue, transmission revenue and expenses, fuel and purchased energy expense, 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 revenue. 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 GAAP, and should be viewed as a supplement to and not a substitute for our results of operations presented in accordance with GAAP. Commodity Margin does not intend to represent gross profit (loss), the most comparable GAAP measure, as an indicator of operating performance and is not necessarily comparable to similarly-titled measures reported by other companies. See Note 13 of the Notes to Consolidated Condensed Financial Statements for a reconciliation of Commodity Margin to income (loss) before taxes by segment.

The following tables show our Commodity Margin and related operating performance metrics by segment for the three months ended March 31, 2009 and 2008. During the first quarter of 2009, we began assessing the performance of our regional segments including the allocation of revenues and expenses from our fuel management, TMG, certain non-region specific natural gas marketing and optimization and other corporate activities that were formerly non-allocated and previously reported as our "Other" segment to our operating segments based upon MWh generated. Additionally, we have modified our definition of Commodity Margin to include cash settlements from our marketing, hedging and optimization activities that were previously included in mark-to-market activity. Our 2008 Commodity Margin by segment information has been recast to conform to the current year presentation. In the "Change" and "% Change" columns below, favorable variances are shown without brackets while unfavorable variances are shown with brackets.

West:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 297	$ 278	$ 19	7%
Commodity Margin per MWh generated	$ 33.23	$ 30.36	$ 2.87	9
MWh generated (in thousands)	8,937	9,157	(220)	(2)
Average availability	90.4%	83.3%	7.1	9
Average total MW in operation	7,246	7,246	—	—
Average capacity factor, excluding peakers	65.2%	66.4%	(1.2)	(2)
Steam Adjusted Heat Rate	7,213	7,228	15	—

West — Commodity Margin in our West segment increased by $19 million, or 7%, for the three months ended March 31, 2009, compared to the three months ended March 31, 2008. Although market spark spreads for the first quarter of 2009 settled substantially lower than the three months ended March 31, 2008, the West segment financial performance improved in the first quarter of 2009 primarily as a result of higher hedge levels and higher average hedge prices as compared to the same period for 2008, as well as from the sale of surplus emission allowances. Despite a 9% increase in our average availability, the impact of weaker market spark spreads led to a decrease in generation of 2% for the three months ended March 31, 2009, compared to the three months ended March 31, 2008.

Texas:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 122	$ 139	$ (17)	(12)%
Commodity Margin per MWh generated	$ 23.43	$ 17.96	$ 5.47	30
MWh generated (in thousands)	5,207	7,741	(2,534)	(33)
Average availability	88.3%	82.0%	6.3	8
Average total MW in operation	7,251	7,251	—	—
Average capacity factor, excluding peakers	33.2%	48.9%	(15.7)	(32)
Steam Adjusted Heat Rate	7,019	6,951	(68)	(1)

Texas — Commodity Margin in our Texas segment decreased by $17 million, or 12%, for the three months ended March 31, 2009, compared to the three months ended March 31, 2008. The positive impact of our hedging activities largely mitigated a weakening market environment, due to soft demand and much weaker spark spreads, resulting in a 33% reduction in generation for the three months ended March 31, 2009. On-peak, market spark spreads were 55% lower in the Houston zone in the first quarter of 2009 compared to the first quarter of 2008, largely driven by reduced ERCOT demand and significantly lower natural gas prices. The price weakness for the first quarter of 2009 as compared to the first quarter of 2008 also led to a 32% decline in our average capacity factor (excluding peakers), despite an 8% increase in average availability.

Southeast:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 61	$ 35	$ 26	74%
Commodity Margin per MWh generated	$ 15.73	$ 13.11	$ 2.62	20
MWh generated (in thousands)	3,879	2,670	1,209	45
Average availability	94.0%	91.0%	3.0	3
Average total MW in operation	6,104	6,254	(150)	(2)
Average capacity factor, excluding peakers	34.4%	22.6%	11.8	52
Steam Adjusted Heat Rate	7,228	7,461	233	3

Southeast — Commodity Margin in our Southeast segment increased by $26 million, or 74%, driven primarily by both higher average hedge prices and higher Market Heat Rates in the first quarter of 2009 compared to 2008. The increase in Market Heat Rates as well as the 45% increase in generation for the three months ended March 31, 2009, compared to 2008 were attributable in part to gas generation displacement of coal generation in certain markets and, to a lesser extent, a 3% increase in average availability. Additionally, some of our plants benefited from the impact of advantageous transmission, customer and transportation agreements in the first quarter of 2009.

North:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 49	$ 61	$ (12)	(20)%
Commodity Margin per MWh generated	$ 39.39	$ 45.59	$ (6.20)	(14)
MWh generated (in thousands)	1,244	1,338	(94)	(7)
Average availability	92.0%	92.0%	—	—
Average total MW in operation	2,822	2,362	460	19
Average capacity factor, excluding peakers	31.8%	34.3%	(2.5)	(7)
Steam Adjusted Heat Rate	7,634	7,419	(215)	(3)

North — Commodity Margin in our North segment decreased by $12 million, or 20%, primarily due to lower average hedge prices during the three months ended March 31, 2009, compared to 2008. Generation volumes declined by 7% in the first quarter of 2009 compared to the same period in 2008. Our average total MW in operation increased 19% for the three months ended March 31, 2009, compared to 2008 due to the reconsolidation of RockGen in December 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 GAAP, and should be viewed as a supplement to and not a substitute for our results of operations presented in accordance with GAAP. Our Exit Credit Facility and certain of our other debt instruments, including the 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 non-cash loss on dispositions of assets. However, we believe that inclusion of our share of the Adjusted EBITDA of our unconsolidated subsidiaries and exclusion of non-cash loss on dispositions of assets are useful in evaluating our overall performance and therefore include these items in our definition of Adjusted EBITDA. Adjusted EBITDA is not intended to represent cash flows from operations or net income (loss) as defined by 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 excludes the impact of reorganization items and impairment charges, among other items as detailed in the below reconciliation. We have recognized substantial reorganization items, both direct and incremental, in connection with our Chapter 11 cases as well as substantial asset impairment charges related to our Chapter 11 filings and actions we have taken with respect to our portfolio of assets in connection with our reorganization efforts. Our reorganization items have decreased significantly since our emergence date and only include income and expenses specific to events as part of our reorganization such as our reconsolidation of our Canadian and other foreign subsidiaries, the planned sales of Fremont and Hillabee development projects and our settlement with Rosetta. We do not expect significant reorganization items in the future. Therefore, we exclude reorganization items and impairment charges from 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 (i) 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; (ii) as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations; and (iii) in communications with our Board of Directors, shareholders, creditors, analysts and investors concerning our financial performance.

The table below provides a reconciliation of Adjusted EBITDA to our GAAP net income (loss) for the three months ended March 31, 2009 and 2008 (in millions):

	2009	2008[1]
GAAP net income (loss)	$ 31	$ (214)
Add:		
Adjustments to reconcile GAAP net income (loss) to Adjusted EBITDA:		
Interest expense, net of interest income	204	406
Depreciation and amortization expense, excluding deferred financing costs[2]	113	122
Income tax expense (benefit)	9	(5)
Reorganization items	3	(279)
Major maintenance expense	62	54
Operating lease expense	12	12
Non-cash gains on derivatives[3]	—	(9)
Unrealized (gains) losses on commodity derivative mark-to-market activity	(125)	187
Adjustments to reflect Adjusted EBITDA from unconsolidated investments[4][5]	(2)	7
Stock-based compensation expense	13	6
Non-cash loss on dispositions of assets	8	6
Non-cash loss on repurchase or extinguishment of debt	—	7
Other	3	1
Adjusted EBITDA	$ 331	$ 301

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(1) Adjusted EBITDA for the three months ended March 31, 2008, has been recast to conform to our current year presentation.

(2) Depreciation and amortization expense in the GAAP net income (loss) calculation on our Consolidated Condensed Statements of Operations excludes amortization of other assets and amounts classified as sales, general and other administrative expenses.

(3) Includes realized non-cash gains on derivatives that do not qualify for hedge accounting.

(4) Recorded on our Consolidated Condensed Statements of Operations in (income) loss from unconsolidated investments in power plants.

(5) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include $(8) million and $1 million in unrealized (gains) losses on mark-to-market activity for the three months ended March 31, 2009 and 2008, respectively.

Risk Management and Commodity Accounting

We actively seek to manage the commodity risks of our portfolio, utilizing multiple strategies of buying and selling power or natural gas to manage our spark spread, or selling Heat Rate transactions.

We utilize derivatives, which are defined to include physical commodity contracts and financial commodity instruments such as swaps and options and NYMEX contracts 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.

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 criteria 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. 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 susceptible 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 the remainder of 2009. 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 utilize a combination of PPAs and other hedging instruments to manage our variability in future cash flows. As of March 31, 2009, the maximum length of our PPAs extend until 24 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 4 and 17 years, respectively. We currently estimate that pre-tax, net gains of $256 million would be reclassified from AOCI into earnings during the next 12 months at March 31, 2009 prices, as the hedged transactions affect earnings assuming constant natural gas and power prices and interest rates over time; 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, management is unable to predict what the actual reclassification from AOCI to earnings (positive or negative) will be for the next 12 months.

Derivatives — We enter into a variety of derivative instruments such as exchange traded and OTC power and natural gas forwards, options and interest rate swaps. Derivative contracts are measured at their fair value and recorded as either assets or liabilities unless they qualify for and we elect the normal purchase or normal sale exemption. All changes in the fair value of contracts accounted for as derivatives are recognized currently in earnings (as a component of our operating revenues, fuel and purchased energy expense, or interest expense) unless specific hedge criteria are met. The hedge criteria requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. The actual amounts that will ultimately be settled will likely vary based on changes in natural gas prices and power prices as well as changes in interest rates. Such variances could be material.

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 and MWh), changing commodity market prices, principally for power and natural gas, liquidity risk, price volatility, counterparty credit risk and changes in interest rates. In that prices for power and natural gas are among the most volatile of all commodity prices, 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. Significant volatility in both natural gas and power prices as well as increased hedging and optimization activities have had a significant impact on the presentation of our derivative assets and liabilities. Our derivative assets and liabilities have increased to $5.2 billion and $(5.2) billion at March 31, 2009, compared to $4.1 billion and $(4.5) billion at December 31, 2008, respectively. As of March 31, 2009, 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%). There is a substantial amount of volatility inherent in accounting for the fair value of these derivatives, and our results during the three months ended March 31, 2009, have reflected this as discussed below.

The change in fair value of our outstanding commodity and interest rate swap derivative instruments from January 1, 2009, through March 31, 2009, is summarized in the table below (in millions):

	Interest Rate Swaps	Commodity Instruments	Total
Fair value of contracts outstanding at January 1, 2009	$ (452)	$ 12	$ (440)
Losses (gains) recognized or otherwise settled during the period	50[1]	(17)[2]	33
Fair value attributable to new contracts	(1)	173	172
Changes in fair value attributable to price movements	(18)	298	280
Change in fair value attributable to nonperformance risk	(23)	(8)	(31)
Fair value of contracts outstanding at March 31, 2009[3]	$ (444)	$ 458	$ 14

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(1) Interest rate settlements consist of (i) recognized losses from interest rate cash flow hedges of $(46) million and (ii) recognized losses from undesignated interest rate swaps of $(4) million (represents a portion of interest expense as reported on our Consolidated Condensed Statements of Operations).

(2) Commodity settlements consist of (i) recognized gains from commodity cash flow hedges of $113 million, (ii) settlement of a commodity contract net of credit reserves of $(79) million, and (iii) losses related to undesignated derivatives of $(17) million (represents a portion of operating revenues and fuel and purchased energy expense as reported on our Consolidated Condensed Statements of Operations).

(3) Net commodity and interest rate swap derivative liabilities reported in Notes 8 and 9 of the Notes to Consolidated Condensed 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 Condensed Statements of Operations as a component (gain or loss) in current earnings.

The components of our total mark-to-market gain (loss) for our commodity instruments and interest rate swaps for the three months ended March 31, 2009 and 2008 are outlined below (in millions):

	2009	2008
Realized gain (loss)[1]	$ (62)	$ 36
Unrealized gain (loss)	126	(203)
Total mark-to-market gain (loss)	$ 64	$ (167)

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(1) Balance includes a non-cash gain from amortization of prepaid power sales agreements of approximately $9 million for the three months ended March 31, 2008.

Our change in AOCI from an accumulated loss of $(158) million at December 31, 2008, to an accumulated loss of $(12) million at March 31, 2009, was primarily driven by the effect of a decrease in power and natural gas prices partially offset by an increase in interest rates and the effect of income taxes.

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 and natural gas. 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 or non-derivative instruments.

The fair value of outstanding derivative commodity instruments at March 31, 2009, based on price source and the period during which the instruments will mature, are summarized in the table below (in millions):

Fair Value Source	2009	2010-2011	2012-2013	After 2013	Total
Prices actively quoted	$ 342	$ 332	$ (9)	$ —	$ 665
Prices provided by other external sources	42	(269)	19	—	(208)
Prices based on models and other valuation methods	—	—	—	1	1
Total fair value	$ 384	$ 63	$ 10	$ 1	$ 458

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 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 three months ended March 31, 2009 and 2008, as well as our VAR at March 31, 2009 and 2008 (in millions):

	2009	2008
Three months ended March 31:		
High	$ 59	$ 52
Low	$ 47	$ 39
Average	$ 52	$ 43
As of March 31	$ 54	$ 52

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 Condensed Financial Statements.

We have also borrowed $725 million under our Exit Credit Facility, as discussed in "— Liquidity and Capital Resources" above to mitigate our liquidity risk.

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 agreements, or master netting agreements 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 a normal purchase or normal sale or whether they are marked-to-market and included in our derivative assets and liabilities on our Consolidated Condensed Balance Sheets. Our counterparty credit quality associated with the net fair value of outstanding derivative commodity instruments is included in our derivative assets and liabilities at March 31, 2009, 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 March 31, 2009)	**2009**	**2010-2011**	**2012-2013**	**After 2013**	**Total**
Investment grade	$ 372	$ 58	$ 10	$ —	$ 440
Non-investment grade	4	—	—	—	4
No external ratings	8	5	—	1	14
Total fair value	$ 384	$ 63	$ 10	$ 1	$ 458

The fair value of our interest rate swaps are validated based upon external quotes. See further discussion of our interest rate swaps under "— Interest Rate Risk."

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. Significant LIBOR increases could have an adverse impact on our future interest expense.

Our fixed-rate debt instruments do not expose us to the risk of loss in earnings due to changes in market interest rates. In general, such a change in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of the fixed rate debt in the open market prior to their maturity.

Currently, we use interest rate swaps to adjust the mix between fixed and floating rate debt as a hedge of our interest rate risk. We do not use interest rate derivative instruments for trading purposes. In order to manage our risk to significant increases in LIBOR, we have effectively hedged $7.1 billion of our variable rate debt through December 31, 2010, through the use of variable to fixed interest rate swaps, the majority of which mature in years 2009 through 2012. To the extent eligible, our interest rate swaps have been designed as cash flow hedges, and changes in fair value are recorded in OCI to the extent they are effective.

Recent Accounting Pronouncements

See Note 1 of the Notes to Consolidated Condensed Financial Statements for a discussion of recent accounting pronouncements.

Item 3. ***Quantitative and Qualitative Disclosures About Market Risk***

See "Risk Management and Commodity Accounting" in Item 2.

Item 4. ***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 pursuant to Rule 13a-15 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.

Changes in Internal Control Over Financial Reporting

During the first quarter of 2009, 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.

PART II — OTHER INFORMATION

Item 1. ***Legal Proceedings***

See Note 12 of the Notes to Consolidated Condensed Financial Statements for a description of our legal proceedings.

Item 2. ***Unregistered Sales of Equity Securities and Use of Proceeds***

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. As set forth in the table below, during the first quarter of 2009, we withheld a total of 234,603 shares in the indicated months. These were the only repurchases of equity securities made by us during this period. We do not have a stock repurchase program.

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
January	35,481	$ 7.41	—	n/a
February	199,122	8.07	—	n/a
March	—	—	—	n/a
Total	234,603	7.97	—	n/a

Item 6. ***Exhibits***

The following exhibits are filed herewith unless otherwise indicated:

EXHIBIT INDEX

Exhibit Number	Description
1.1	Underwriting Agreement, dated April 23, 2009, among Calpine Corporation, the selling stockholder named therein and Morgan Stanley & Co. Incorporated, the underwriter named therein (incorporated by reference to our Current Report on Form 8-K/A filed with the SEC on April 24, 2009).
10.1	Letter re Employment Offer, dated February 6, 2009, between the Company and Michael D. Rogers.*†
10.2	Calpine Corporation 2009 Calpine Incentive Plan.*†
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 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.*

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* Filed herewith.

† Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements 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

Date: May 7, 2009

By: /s/ JIM D. DEIDIKER
Jim D. Deidiker
Senior Vice President and
Chief Accounting Officer

Date: May 7, 2009

The following exhibits are filed herewith unless otherwise indicated:

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* Filed herewith.

† Management contract or compensatory plan or arrangement.

EXHIBIT 10.1

February 6, 2009

Mike Rogers
4018 Bell Hollow Lane
Katy, Texas 77494

Dear Mike,

On behalf of Calpine Corporation, I am pleased to extend an offer to continue your regular, full-time employment with Calpine, in a new exempt position of Senior Vice President, Geothermal Operations, located in Middletown, California. This new position goes into effect of February 16, 2009. Details of this offer are provided below:

Title:	Senior Vice President, Geothermal Operations
Reporting to:	Tom Webb, Interim SVP, Calpine Power Operations
Base Salary:	$17,307.69 paid bi-weekly (annualized at $450,000.00 for 2009). Base Salary will be reevaluated in 2010 and thereafter.
Annual Bonus Program:	You will continue to be eligible to participate in the Calpine Incentive Plan (CIP), which provides for an annual bonus based both on corporate financial results and individual performance. Your 2009 CIP target will be 75% of your annual bas wages and can be increased or decreased in accordance with the corporate financial results and your individual performance.
Emergence Equity Grants:	Your Executive Emergence Non-Qualified Stock Options and Executive Emergence Restricted Stock Grants will vest on February 16, 2009.
Change in Control and Severance Benefits Plan:	We have agreed on three scenarios: 1. You may resign your employment for any reason on or before December 31, 2009 and receive severance benefits consistent with the Calpine Corporation Change in Control and Severance Benefits Plan in effect as of the date of this letter, at 100% of your 2008 bonus target. 2. If you are involuntarily terminated without cause or if you resign for good reason, before December 31, 2010, you will receive severance benefits consistent with the Calpine Corporation Change in Control and Severance Benefits Plan in effect as of the date of this letter, at 100% of your 2008 bonus target. "Good reason" and "cause" are defined in the Calpine Corporation Change in Control and Severance Benefits Plan. After December 31, 2010, Calpine's then in effect change in control and severance benefits plan shall apply. 3. If Calpine hires a regular, full-time Senior Vice President of Calpine Power Operations before July 1, 2010, you will have the right to terminate your employment if you reasonably determine that you are not compatible with that Senior Vice President, up to six months after that individual's hire date. If you resign for that reason, you will receive severance benefits consistent with the Calpine Corporation

	Change in Control and Severance Benefits Plan in effect as of the date of this letter, at 100% of your 2008 bonus target. As a condition of receiving the benefits described in these three scenarios, you agree that if you resign your employment for any of the above reasons, you will provide Calpine with 90 days' advance written notice of your resignation.
Benefits Summary:	You will continue to be covered by Calpine's competitive, comprehensive benefits package.
Relocation:	You are eligible for Level 4 relocation assistance. Relocation assistance must be refunded in full to Calpine should you voluntarily terminate your employment within twelve (12) months from your employment date.

This offer does not constitute a binding contract of employment. Calpine's employment arrangements may be terminated by either party, at will.

Please sign both copies of the letter, retain one for your files and return one to Human Resources in the attached self-addressed stamped envelope. Please contact Kelly Zelinski at 408-792-1111 with any questions.

Mike, we look forward to your serving as Senior Vice President of Geothermal Operations.

Very truly yours,

CALPINE CORPORATION

/s/ THAD HILL
Thad Hill, EVP and Chief Commercial Ops

/s/ MIKE ROGERS
Mike Rogers

February 25, 2009
Date

EXHIBIT 10.2

CALPINE CORPORATION

2009 Calpine Incentive Plan

I. Effective Date

The 2009 Calpine Incentive Plan (the “CIP” or the “Plan”) is effective as of January 1, 2009.

II. Plan Purpose

The CIP is a key element of Calpine Corporation’s (“Company”) total compensation program and is designed to attract, motivate, retain and reward eligible employees. The plan rewards eligible employees by allowing them to receive bonuses based upon how well the Company performs against certain financial objectives, how an individual personally performs and how well the individual’s plant/department performs (when applicable). In order for any bonuses to be earned and paid, the Company must meet minimally acceptable performance targets. If those targets are not met, no bonuses will be paid. If those targets are met, then bonuses will be paid based on a combination of Company performance, individual performance and the individual’s plant/department performance (when applicable).

III. Plan Eligibility

All regular full time (working 30 or more hours per week), non-collective bargaining unit employees who will not receive a benefit from another Company incentive plan during 2009 are eligible to participate in the Plan.

IV. Bonus Pool Determination

The aggregate CIP bonus pool amount approved by the Compensation Committee of the Board of Directors (the “Committee”), is determined in the following steps:

1. Prior to the start of, or early in each performance period, the Company shall confirm the business/performance goals for the Company (“Corporate Goals”) and/or for various plant/departments (“Plant/Department Goals”) for that period. For the current performance period, Exhibit A attached hereto provides specific Corporate Goals and the areas in which Corporate Goals and Plant/Department Goals will be evaluated.

2. During the fiscal quarter following the performance period (which is the entire calendar year), the Plan Administrator shall review how the actual results for the

period compared to the Corporate Goals and Plant/Department Goals for that period and determine the level of achievement of the various goals, expressed as a percentage. As required, the Committee will review and approve, modify, adjust or cancel the achievement in its sole discretion.

3. The sum each participant's "Annual Cash Bonus Target" which is each participant's Target Percentage (described in Section V (1) below) multiplied by his or her Compensation (as defined in Section V(2) below), for the calendar year to which Corporate Goals and/or Plant/Department Goals (as defined in Section IV(1) above) and Individual Goals (as defined in Section V(3)) apply, establishes the target aggregate CIP bonus pool ("Aggregate Target CIP Bonus Pool").

4. The percentage of goal achievement shall be applied to the Aggregate Target CIP Bonus Pool, and may result in a final actual aggregate CIP bonus pool ("Final Aggregate CIP Bonus Pool") greater than, or less than, the sum each participant's Annual Cash Bonus Target. As a general rule, the level of the Final Aggregate CIP Bonus Pool shall be consistent with the Company's level of Corporate Goal and/or Plant/Department Goals achievement.

   Based upon the achievement of the Corporate Goals and/or Plant/Department Goals, the Committee may adjust the Aggregate Target CIP Bonus Pool up or down based on unplanned circumstances or events.

V. <u>Participant Bonus Determination</u>

Although participant bonus determinations are completely at the discretion of the Plan Administrator and subject to the achievement of Corporate Goals and/or Plant/Department Goals, many factors are taken into consideration in determining an individual participant's bonus under the Plan.

The bonus amount allocated to a participant ("Bonus") is generally determined by the following factors:

1. **Position** – Each eligible position is associated with a job code that is assigned a target percentage based on the level of responsibility and market practices for the position ("Target Percentage"). The Target Percentage, which is based on market data and internal/Calpine discretion (provided that a 16B officer's is based on market data and the discretion of the Board of Directors of Calpine), will be communicated to each participant upon hire, placement in, or promotion to any CIP eligible position.

2. **Compensation** – The amount of a participant's Compensation, which is a participant's base salary and overtime pay, earned in a CIP eligible position during a performance period is directly related to a participant's Bonus. The "Compensation" for a participant shall be prorated for any partial service on account of disability, leaves, promotions or any other position changes.

"Compensation" does not include step up pay, time off for leave of absences or supplemental payments, including but not limited to bonuses, awards and vacation payouts.

3. **Participant Job Performance** – An additional component in calculating a participant's Bonus is the attainment of specific individual goals and objectives, which are established by the participant along with the participant's respective manager at the beginning of the measurement period ("Individual Goals"). Individual Goals may be inapplicable in some circumstances.

4. **Mix of Corporate Goals, Plant/Department Goals and Individual Goals** – Bonuses are determined based on a combination, or mix, of the achievement of Corporate Goals, Plant/Department Goals and Individual Goals (as applicable).

5. **Other Factors Considered:**

- Foremost are Calpine's overriding principles of ethical conduct and integrity. It is expected that each participant will conduct Calpine's business in an open and honest fashion and actions, and that decisions will represent the Company with honor and distinction in the face of public scrutiny.

- Furthermore, a participant's compliance with all applicable laws and Company policies, procedures and standards (including, but not limited to, the Code of Conduct, the Risk Management Procedures Manual, the Antitrust Policy, the Safety and Health Policy, the Equal Employment Opportunity Policy and NERC, FERC and any other regulatory laws, rules or regulations) is an essential consideration in determining bonus eligibility and amount. In addition, a participant's Bonus under the Plan may be adjusted for his or her individual performance and contribution, as determined by the participant's manager.

VI. <u>Payment of Bonus</u>

Each Bonus under the Plan will be calculated based on attainment of goals and paid as follows:

- Provided the Corporate Goals and/or Department Goals are achieved as set forth in Exhibit A, it is intended that the Bonus will be paid between January 1, 2010 and March 15, 2010, but it will be paid no later than December 31, 2010.

- Participants in the Transition Incentive Award program of the CIP: The CIP also provides a limited number of awards to participants under the Transition Incentive Provision ("Exhibit B"). These employees are engaged in activities such as asset sales, plant closings, etc. which may, by the nature of the activity, result in the elimination of their jobs. Employees in this classification will be advised of their respective participation based on criteria determined by the Company from time to time.

- In all cases, bonus payments will be subject to all applicable taxes and any applicable and appropriate deductions for garnishments, 401(k) Retirement Savings Plan, and other deductions or withholdings.

VII. Transfers and New Hires

In the event that a participant transfers from one position to another during the course of the performance period, or is a new hire, his/her Plan bonus for the year will be calculated on a pro-rated basis to reflect the actual time spent in each position and the bonus target for each position during the performance period. An employee hired on or after November 1 is not eligible to participate in the CIP for the calendar year in which he or she was hired.

VIII. Retirements, Disability, Death and Terminations

Except as provided below, participants are eligible to receive a bonus under this Plan provided they remain actively employed on the day bonus payments are paid. Participants in the Transition Incentive Award program of the CIP are exempt from this provision.

Notwithstanding the foregoing, in the event of a participant's retirement (provided such participant qualified under the Company's retirement policy), short-term or long-term disability or death during a Plan year, his/her Bonus will be pro-rated to reflect the actual time in active service during the Plan year. If a Plan participant dies, retires or becomes subject to short-term or long-term disability after the conclusion of a performance period, but prior to the bonus payout for such period, he or she will still be eligible to receive the entire Bonus under the Plan for such period.

Except as otherwise provided hereunder, any participant whose employment is terminated by the Company for any reason (including such termination by the Company after a participant becomes eligible for retirement) or who voluntarily resigns (except for retirement) prior to the Bonus payout is not eligible to receive a bonus payment under such program.

IX Administration

The Plan will be administered by the Plan Administrator who shall be Calpine's Chief Executive Officer, or the Company officer designated by the Chief Executive Officer from time to time (i.e., SVP Human Resources, etc.). The Plan Administrator shall have broad authority to interpret the terms and conditions of the Plan, subject to the following decisions reserved for the Committee:

1. As required, the approval of the Company's financial and non-financial goals discussed in Section IV above; and

2. Interpretation of the Plan on any matters in which the Chief Executive Officer or the Plan Administrator is not a disinterested party.

Furthermore, the Plan Administrator must approve any modifications, amendments, or adjustments to the Plan or any of its key provisions and all bonus payments. In addition, all bonus payments under this Plan are subject to the review and the approval of the Chief Executive Officer. Any decisions of the Plan Administrator in the interpretation of the Plan may be appealed in writing to the Committee. However, any decision of the majority of the Committee is final and binding on all parties.

X Disputes

If a Plan participant disputes a Bonus payment or the absence of a payment under such program, he or she must submit a claim in writing describing the claim to the Plan Administrator. The Plan Administrator will respond to the claim within a reasonable time. Any decisions of the Plan Administrator may be appealed in writing to the Committee. However, any decision of a majority of the Committee is final and binding on all parties.

XI Discretion in Amendment/Termination

Distribution and payout of all Bonus amounts under the CIP are at the sole discretion of the Plan Administrator. The Plan Administrator may at any time and for any reason, amend, alter, suspend or terminate this Plan, subject to the approval of the Committee. Any amendment, supplement, or exception to this Plan must be in writing and will be communicated to all eligible participants. Likewise, any superseding management incentive plan must be in writing and expressly state that it supersedes this Plan. The Committee may in its discretion suspend any and all payments under the Plan.

XII No Employment Rights

Notwithstanding anything to the contrary herein, each Plan participant's employment with the Company is and shall continue to be at-will. A participant's employment with the Company may be terminated at any time by the participant or the Company, with or without cause and with or without notice, as permitted by law.

XIII Governing Law

The validity, interpretation, construction and performance of this Plan shall be governed in accordance with Texas law, except for its conflict of laws provisions, unless a superseding federal law is applicable or, in the case of Canada, unless a superseding law under Canadian jurisdiction is applicable.

XIV No Assignment

Without the written consent of the Plan Administrator, no participant may assign any right or obligation under this Plan to any other person or entity. Notwithstanding the foregoing, the terms of this Plan and all rights of the participant hereunder shall inure to the benefit of, and be enforceable by, the participant's personal and legal representatives, executors, administrators, successors, heirs, distributes, devisees or legatees.

XV Integration

This document and each exhibit hereto represent the entire agreement and understanding between the Company and the participants in the Plan as to the subject matter herein, and therefore supersede all prior or contemporaneous agreements, whether written or oral.

XVI Severability

The invalidity of unenforceability of any provision or provisions of this Plan shall not affect the validity or enforceability of any other provision hereof, which shall remain in full force and effect.

EXHIBIT A
2009

Pool Funding and CIP Bonus Plan Goals/Metrics

Pool Funding

- Each plan participant has an Annual Cash Bonus Target that equals the product of his/her Compensation times the Target Percentage associated with his/her job level. The Aggregate Target CIP Bonus Pool equals the sum of the participants' Annual Cash Bonus Targets.

- Based upon results, the Bonus Pool may be adjusted upward or downward based on unplanned extra ordinary events.

*** * * * ***

- **Corporate Goal:** The Company must meet a minimum threshold performance of at least 80 percent of projected adjusted EBITDA in order for the CIP program to be funded in 2009. For 2009, the projected adjusted EBITDA target is $1,687 million dollars. Eighty percent of this target is $1,349 million.

- **Corporate and Plant/Department Goal Performance:** Performance at the Corporate and Plant/Department levels will directly relate to how the Company and Plant/Department (where applicable) satisfy performance measure targets in the following areas: Economic Commodity Margin and Other Income, Expenses, CAPEX/Major Maintenance Expenses and Strategic Initiatives. (See attached Addendum to Exhibit A for more details.) Some Plant/Departments will affect all of the areas, while others will affect as few as one area. This will be accounted for. Plant performance will include, but not be limited to, evaluation of safety, environmental compliance and controllable expenses.

With the exception of awards paid under the Transition Incentive program (Exhibit B) that may involve the elimination of a participant's own position, participants must be actively employed on the date of the payment of the Bonus in order to receive payment.

* * * * *

EXHIBIT B
<u>2009</u>
<u>Transition Incentive Plans</u>

In connection with activities necessary to the successfully disposition of assets, closing of plants and similar activities designed to support the restructuring of Calpine, there may be a number of employees who, by the nature of their activities, eliminate their respective jobs. The Transition Incentive Plans provide a program that rewards these participants for their work in completing assignments and specific transactions that enhance Calpine’s value.

A. Transaction/Transition Bonus

To be paid to CIP eligible employees who are working on a specific assignment with a targeted end date. In the majority of cases, the completion of the assignment will result in the affected employee’s lay-off. Generally, the Transaction/Transition Bonus for an affected employee will be calculated based upon his/her Annual Cash Bonus Target. Any Transaction/Transition Bonus may be paid during the assignment or specific transaction, upon the assignment’s or transaction’s completion, or both. The Transaction/Transition bonus is paid in lieu of a CIP bonus. A Transaction/Transition Bonus shall be paid within 2½ months following the assignment’s or transaction’s completion date.

Subject to a written agreement, an employee who voluntarily resigns or is terminated by the Company for any reason prior to successful completion of the specified assignment will not be eligible for a Transaction/Transition bonus payout.

B. Construction Completion Bonus

To be paid to construction, engineering and commissioning employees at the level of Director and below assigned to specific capital or construction projects. Each specified project will have a construction completion bonus pool assigned to it. A Construction Completion Bonus will be made on a discretionary basis by management based upon an employee’s contribution to that project. A Construction Completion Bonus may be paid during the project, upon completion of the construction project or both. Each Construction Completion Bonus may be paid to employees who are no longer employed with Calpine at the time the entire construction project is completed as long as management deems their services to have been satisfactorily completed and no longer needed at some time prior to the project’s completion date.

Subject to a written agreement, an employee who voluntarily resigns or is terminated by the Company for any reason prior to completion of the construction project will not be eligible for a Construction Completion Bonus payout.

EXHIBIT 31.1

CERTIFICATIONS

I, Jack A. Fusco, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Calpine Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2009

/s/ JACK A. FUSCO

Jack A. Fusco
President, Chief Executive Officer
and Director
Calpine Corporation

EXHIBIT 31.2

CERTIFICATIONS

I, Zamir Rauf, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Calpine Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2009

/s/ ZAMIR RAUF

Zamir Rauf
Executive Vice President and
Chief Financial Officer
Calpine Corporation

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Calpine Corporation (the “Company”) on Form 10-Q for the period ending March 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge, based upon a review of the Report:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operation of the Company.

/s/ JACK A. FUSCO	/s/ ZAMIR RAUF
Jack A. Fusco	Zamir Rauf
President, Chief Executive Officer	Executive Vice President and
and Director	Chief Financial Officer
Calpine Corporation	Calpine Corporation

Dated: May 7, 2009

A signed original of this written statement required by Section 906 has been provided to Calpine Corporation and will be retained by Calpine Corporation and furnished to the Securities and Exchange Commission or its staff upon request.