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 September 30, 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

Not Applicable
(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: 442,374,038 shares of Common Stock, par value $.001 per share, outstanding on October 27, 2009.

CALPINE CORPORATION AND SUBSIDIARIES

REPORT ON FORM 10-Q
For the Quarter Ended September 30, 2009

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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 customers, suppliers, service providers and other contractual 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 including the effects of fluctuations in liquidity and volatility in the energy commodities markets including our ability to hedge risks;
- Our ability to manage our significant liquidity needs and to comply with covenants under our First Lien Credit Facility, our First Lien Notes 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;
- 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 regional 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, variables associated with the injection of waste water to the steam reservoir and potential regulations or other requirements related to seismicity concerns that may delay or increase the cost of developing or operating geothermal resources;
- 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;
- Risks associated with the operation, construction and development of power plants including unscheduled outages or delays and plant efficiencies; and
- 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, Texas 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 as adjusted for the effects of (a) impairment charges, (b) reorganization items, (c) major maintenance expense, (d) operating lease expense, (e) any non-cash realized gains on derivatives and any unrealized gains or losses on commodity derivative mark-to-market activity, (f) adjustments to reflect the Adjusted EBITDA from our unconsolidated investments, (g) claim settlement income, (h) stock-based compensation expense (income), (i) non-cash gains or losses on sales, dispositions or impairments of assets, (j) non-cash gains and losses from intercompany foreign currency translations, (k) any gains or losses on the repurchase or extinguishment of debt and (l) any other extraordinary, unusual or non-recurring items
AOCI	Accumulated Other Comprehensive Income
ASC	FASB Accounting Standards Codification, effective July 1, 2009, which summarizes all authoritative GAAP into one source
Auburndale	Auburndale Holdings, LLC
Average 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	Together, the $680,000,000 Third Priority Secured Floating Rate Notes Due 2011, issued by CalGen and CalGen Finance Corp.; and the $150,000,000 11 1/2% Third Priority Secured Notes Due 2011, issued by CalGen and CalGen Finance Corp., in each case repaid on March 29, 2007
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
CARB	California Air Resources Board
CCAA	Companies' Creditors Arrangement Act (Canada)
CCFC	Calpine Construction Finance Company, L.P.
CCFC Finance	CCFC Finance Corp.
CCFC Guarantors	Hermiston Power LLC and Brazos Valley Energy LLC, wholly owned subsidiaries of CCFC
CCFC New Notes	The $1.0 billion aggregate principal amount of 8.0% Senior Secured Notes due 2016 issued May 19, 2009, by CCFC and CCFC Finance
CCFC Old Notes	The $415 million total aggregate principal amount of Second Priority Senior Secured Floating Rate Notes Due 2011 issued by CCFC and CCFC Finance, comprising $365 million aggregate principal amount issued August 14, 2003, and $50 million aggregate principal amount issued September 25, 2003, and redeemed on June 18, 2009
CCFC Refinancing	The issuance of the CCFC New Notes on May 19, 2009, pursuant to Rule 144A and Regulation S under the Securities Act, and the related transactions including repayment of the CCFC Term Loans and the redemption of the CCFC Old Notes and CCFCP Preferred Shares
CCFC Term Loans	The $385 million First Priority Senior Secured Institutional Term Loans due 2009 borrowed by CCFC under the Credit and Guarantee Agreement, dated as of August 14, 2003, among CCFC, the guarantors party thereto, and Goldman Sachs Credit Partners L.P., as sole lead arranger, sole bookrunner, administrative agent and syndication agent, and repaid on May 19, 2009
CCFCP	CCFC Preferred Holdings, LLC
CCFCP Preferred Shares	The $300 million of six-year redeemable preferred shares due 2011 issued by CCFCP and redeemed on or before July 1, 2009
CFR	Code of Federal Regulations
CFTC	U.S. Commodities Futures Trading Commission
Channel Energy Center	Our 593 MW natural gas-fired cogeneration power plant located in Houston, Texas
Chapter 11	Chapter 11 of the Bankruptcy Code
CO_2	Carbon dioxide
Cogeneration	Using a portion or all of the steam generated in the 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

ABBREVIATION	DEFINITION
Commodity expense	The sum of our expenses from fuel expense, purchased power and natural gas expense, fuel transportation expense, transmission expense and cash settlements from our marketing, hedging and optimization activities that are included in our mark-to-market activity in fuel and purchased energy expense
Commodity Margin	Non-GAAP financial measure that includes power and steam revenues, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, RGGI compliance costs, and cash settlements from our marketing, hedging and optimization activities that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenues
Commodity revenue	The sum of our revenues from power and steam sales, sales of purchased power and natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue, and cash settlements from our marketing, hedging and optimization activities that are included in our mark-to-market activity in operating revenues
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 which were settled with reorganized Calpine Corporation common stock on the Effective Date
CPUC	California Public Utilities Commission
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
FASB	Financial Accounting Standards Board
FDIC	Federal Deposit Insurance Corporation

ABBREVIATION	DEFINITION
FERC	Federal Energy Regulatory Commission
First Lien 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
First Lien Facilities	Together, the First Lien Credit Facility and the Bridge Facility
First Lien Notes	The approximately $1.2 billion aggregate principal amount of 7.25% senior secured notes due 2017 issued on October 21, 2009 for a like principal amount of First Lien Credit Facility term loans as a permitted debt exchange pursuant to the First Lien Credit Facility, which retired an aggregate principal amount of term loans under the First Lien Credit facility equal to the aggregate principal amount of notes issued
Fremont	Fremont Energy Center, LLC
GAAP	Generally accepted accounting principles in the United States
GE	General Electric International, Inc.
Geysers Assets	Our geothermal power plant assets located in northern California consisting of 15 operating power plants with 17 turbines and two plants not in operation
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
IRS	U.S. Internal Revenue Service
ISO	Independent System Operator
Knock-in Facility	Letter of Credit Facility Agreement, dated as of June 25, 2008, among Calpine Corporation as borrower and Morgan Stanley Capital Services Inc., as issuing bank which matured on June 30, 2009
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
Metcalf	Metcalf Energy Center, LLC
MMBtu	Million Btu
MRTU	California ISO's Market Redesign and Technology Update
MW	Megawatt(s), a measure of plant capacity
MWh	Megawatt hour(s), a measure of power produced

ABBREVIATION	DEFINITION
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
Panda	Panda Energy International, Inc. and related party PLC II, 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
Pomifer	Pomifer Power Funding, LLC, a subsidiary of Arclight Energy Partners Fund I, L.P.
PPA(s)	Any term power purchase agreement or other contract for a physically settled sale (as distinguished from a financially settled future, option or other derivative or hedge transaction) of any electric power product, including electric power, capacity and/or ancillary services, in the form of a bilateral agreement or a written or oral confirmation of a transaction between two parties to a master agreement, including sales related to a tolling transaction in which 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
RGGI	Regional Greenhouse Gas Initiative
RockGen	RockGen Energy LLC
RPS	Renewable portfolio standards
SDG&E	San Diego Gas & Electric Company
SDNY Court	U.S. District Court for the Southern District of New York
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 which were repaid on the Effective Date
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 which were repaid on the Effective Date
Second Priority Senior Secured Term Loans	Calpine Corporation's Senior Secured Term Loans due 2007, issued as of July 16, 2003, among Calpine, as borrower, Goldman Sachs Credit Partners, L.P., as sole lead arranger, sole bookrunner and administrative agent and the various co-arrangers, managing agents and lenders named therein
Securities Act	U.S. Securities Act of 1933, as amended
SO_2	Sulfur dioxide
Spark spread(s)	The difference between the sales price of power per MWh and the cost of fuel to produce it

ABBREVIATION	DEFINITION
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 which were settled with reorganized Calpine Corporation common stock on the Effective Date
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 STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in millions, except share and per share amounts)			
Operating revenues	$ 1,847	$ 3,190	$ 4,995	$ 7,969
Cost of revenue:				
Fuel and purchased energy expense	1,030	2,322	2,967	5,935
Plant operating expense	196	198	654	636
Depreciation and amortization expense	108	110	330	329
Other cost of revenue	20	26	63	88
Total cost of revenue	1,354	2,656	4,014	6,988
Gross profit	493	534	981	981
Sales, general and other administrative expense	38	58	131	154
(Income) loss from unconsolidated investments in power plants	13	202	(27)	189
Other operating expense	5	2	14	15
Income from operations	437	272	863	623
Interest expense	198	212	615	837
Interest (income)	(3)	(11)	(13)	(38)
Debt extinguishment costs	16	—	49	13
Other (income) expense, net	4	18	8	16
Income (loss) before reorganization items and income taxes	222	53	204	(205)
Reorganization items	(8)	(2)	(2)	(263)
Income before income taxes	230	55	206	58
Income tax expense (benefit)	(7)	(80)	17	(60)
Net income	237	135	189	118
Net loss attributable to the noncontrolling interest	1	1	3	1
Net income attributable to Calpine	$ 238	$ 136	$ 192	$ 119
Basic earnings per common share:				
Weighted average shares of common stock outstanding (in thousands)	485,736	485,076	485,619	485,027
Net income per common share attributable to Calpine – basic	$ 0.49	$ 0.28	$ 0.40	$ 0.25
Diluted earnings per common share:				
Weighted average shares of common stock outstanding (in thousands)	486,585	485,744	486,171	485,588
Net income per common share attributable to Calpine – diluted	$ 0.49	$ 0.28	$ 0.39	$ 0.25

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	September 30, 2009	December 31, 2008
	(in millions, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 913	$ 1,657
Accounts receivable, net of allowance of $19 and $42	880	850
Inventory	164	163
Margin deposits and other prepaid expense	418	776
Restricted cash, current	461	337
Current derivative assets	2,032	3,653
Other current assets	37	64
Total current assets	4,905	7,500
Property, plant and equipment, net	11,683	11,908
Restricted cash, net of current portion	44	166
Investments	210	144
Long-term derivative assets	288	404
Other assets	571	616
Total assets	$ 17,701	$ 20,738
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 605	$ 574
Accrued interest payable	71	85
Debt, current portion	421	716
Current derivative liabilities	2,097	3,799
Income taxes payable	7	5
Other current liabilities	245	437
Total current liabilities	3,446	5,616
Debt, net of current portion	9,064	9,756
Deferred income taxes, net of current portion	64	93
Long-term derivative liabilities	421	698
Other long-term liabilities	207	203
Total liabilities	13,202	16,366
Commitments and contingencies (see Note 14)		
Stockholders' equity:		
Preferred stock, $.001 par value per share; 100,000,000 shares authorized; none issued and outstanding at September 30, 2009, and December 31, 2008	—	—
Common stock, $.001 par value per share; 1,400,000,000 shares authorized; 442,699,628 shares issued and 442,372,296 shares outstanding at September 30, 2009; 429,025,057 shares issued and 428,960,025 shares outstanding at December 31, 2008	1	1
Treasury stock, at cost, 327,332 shares at September 30, 2009, and 65,032 shares at December 31, 2008	(3)	(1)
Additional paid-in capital	12,249	12,217
Accumulated deficit	(7,497)	(7,689)
Accumulated other comprehensive loss	(250)	(158)
Total Calpine stockholders' equity	4,500	4,370
Noncontrolling interest	(1)	2
Total stockholders' equity	4,499	4,372
Total liabilities and stockholders' equity	$ 17,701	$ 20,738

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2009	2008
	(in millions)	
Cash flows from operating activities:		
Net income	$ 189	$ 118
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense [1]	399	411
(Income) loss from unconsolidated investments in power plants	(27)	189
Debt extinguishment costs	9	7
Deferred income taxes	15	(60)
Loss on disposal of assets, excluding reorganization items	29	6
Mark-to-market activity, net	(67)	15
Stock-based compensation expense	30	36
Reorganization items	(7)	(331)
Other	6	21
Change in operating assets and liabilities:		
Accounts receivable	(23)	126
Derivative instruments	(239)	(45)
Other assets	387	96
Accounts payable, LSTC and accrued expenses	13	(76)
Other liabilities	(177)	(158)
Net cash provided by operating activities	537	355
Cash flows from investing activities:		
Purchases of property, plant and equipment	(140)	(108)
Disposals of property, plant and equipment	—	16
Proceeds from sale of power plants, turbines and investments	—	398
Cash acquired due to reconsolidation of the Canadian Debtors and other deconsolidated foreign entities	—	64
Contributions to unconsolidated investments	(19)	(14)
Return of investment from unconsolidated investments	—	26
(Increase) decrease in restricted cash	(2)	145
Other	(3)	7
Net cash provided by (used in) investing activities	(164)	534
Cash flows from financing activities:		
Repayments of notes payable	(106)	(98)
Repayments of project financing	(889)	(274)
Borrowings from project financing	1,028	356
Repayments of DIP Facility	—	(98)
Borrowings under First Lien Facilities	—	3,523
Repayments on First Lien Facilities	(770)	(1,460)
Borrowings under Commodity Collateral Revolver	—	100
Repayments on Second Priority Debt	—	(3,672)
Repayments on capital leases	(34)	(29)
Redemptions of preferred interests	(310)	(166)
Financing costs	(34)	(207)
Derivative contracts classified as financing activities	—	70
Other	(2)	2
Net cash used in financing activities	(1,117)	(1,953)
Net decrease in cash and cash equivalents	(744)	(1,064)
Cash and cash equivalents, beginning of period	1,657	1,915
Cash and cash equivalents, end of period	$ 913	$ 851

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

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

	Nine Months Ended September 30,	
	2009	2008
Cash paid (received) during the period for:		
Interest, net of amounts capitalized	$ 563	$ 873
Income taxes	$ 6	$ 16
Reorganization items included in operating activities, net	$ 5	$ 124
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	$ —
Change in capital expenditures included in accounts payable	$ 3	$ 13
Settlement of LSTC through issuance of reorganized Calpine Corporation common stock	$ —	$ 5,200
DIP Facility borrowings converted into exit financing under the First Lien 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.

CALPINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS
September 30, 2009
(Unaudited)

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 economically 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. In accordance with Financial Reporting by Entities in Reorganization under the Bankruptcy Code prescribed by GAAP, certain income, expenses, realized gains and losses and provisions for losses that were realized or incurred in our Chapter 11 cases are recorded in reorganization items on our Consolidated Condensed Statements of Operations. See Note 13 for further information regarding our reorganization items.

Canadian Subsidiaries — As a result of filings by the Canadian Debtors under the CCAA in the Canadian Court, we deconsolidated the Canadian Debtors and their direct and indirect subsidiaries, constituting most of our 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 the Canadian Debtors and the other deconsolidated 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 from Chapter 11 proceedings in the U.S. allowed us to maintain our equity interest in the Canadian Debtors and the other deconsolidated foreign entities, whose principal assets included various working capital items and a 50% ownership interest in Whitby, an equity method investment. As a result, we regained control over the Canadian Debtors and the other deconsolidated 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 use the equity method of accounting to record our net interest in OMEC, a VIE where we have determined that we are not the primary beneficiary, Greenfield LP, a joint venture interest, and Whitby, a less-than-majority-owned company in which we exercise significant influence over operating and financial policies. Our share of net income (loss) is calculated according to our equity ownership or according to the terms of the applicable partnership agreement. See Note 3 for further discussion of our VIEs and unconsolidated investments.

Reclassifications — Certain reclassifications have been made to our December 31, 2008 Consolidated Condensed Balance Sheet, our Consolidated Condensed Statements of Operations for the three and nine months ended September 30, 2008, and our Consolidated Condensed Statement of Cash Flows for the nine months ended September 30, 2008, to conform to the current period presentation. Our reclassifications are summarized as follows:

- We adopted the new accounting requirements under GAAP for noncontrolling interests in consolidated financial statements effective January 1, 2009, and accordingly have 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 "New Accounting Requirements and Disclosures" for a further discussion regarding this requirement.
- Our (income) loss from unconsolidated investments in power plants was previously included within other operating expense, but is now included as a separate line item on our Consolidated Condensed Statements of Operations.
- We have reclassified certain amounts within our cash flows used in operating activities on our Consolidated Condensed Statement of Cash Flows for the nine months ended September 30, 2008, to separately state non-cash debt extinguishment costs previously reflected in depreciation and amortization expense and unrealized mark-to-market activity previously reflected in our changes in derivative instruments, in order to conform to our current period presentation.

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 the Consolidated Condensed Financial Statements. Actual results could differ from those estimates.

Fair Value of Financial Instruments — The carrying values of accounts receivable, accounts payable and other receivables and payables approximate their respective fair values due to their short-term maturities. See Note 6 for disclosures regarding the fair value of our debt instruments.

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 utilities and 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 or their credit rating declines.

Cash and Cash Equivalents — We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. We have certain project finance facilities and lease agreements that require us to establish and maintain segregated cash accounts which have been pledged as security in favor of the lenders under such project finance facilities, and the use of certain cash balances on deposit in such accounts is limited, at least temporarily, to the operations of the respective projects. At September 30, 2009, and December 31, 2008, we had cash and cash equivalents of $232 million and $296 million, respectively, that were subject to such project finance facilities and lease agreements.

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

The table below represents the components of our restricted cash as of September 30, 2009, and December 31, 2008 (in millions):

	September 30, 2009			December 31, 2008		
	Current	Non-Current	Total	Current	Non-Current	Total
Debt service	$ 163	$ 26	$ 189	$ 102	$ 121	$ 223
Rent reserve	38	—	38	34	—	34
Construction/major maintenance	107	9	116	72	18	90
Security/project/insurance	116	1	117	96	1	97
Collateralized letters of credit and other credit support	—	—	—	7	1	8
Other	37	8	45	26	25	51
Total	$ 461	$ 44	$ 505	$ 337	$ 166	$ 503

New Accounting Requirements and Disclosures

Accounting Standards Codification and GAAP Hierarchy — Effective for interim and annual periods ending after September 15, 2009, the Accounting Standards Codification and related disclosure requirements issued by the FASB became the single official source of authoritative, nongovernmental GAAP. The ASC simplifies GAAP, without change, by consolidating the numerous, predecessor accounting standards and requirements into logically organized topics. All other literature not included in the ASC is non-authoritative. We adopted the ASC as of September 30, 2009, which did not have any impact on our results of operations, financial condition or cash flows as it does not represent new accounting literature or requirements; however, it did change our references to authoritative sources of GAAP to the new ASC nomenclature.

Fair Value Measurements of Non-Financial Assets and Non-Financial Liabilities — Effective for interim and annual periods beginning after November 15, 2008, GAAP established new standards related to fair value measurements for non-financial assets and liabilities. These new standards do not apply to assets and liabilities that were not previously required to be recorded at fair value, but do apply when other accounting pronouncements require fair value measurements. The new standards also define fair value, establish a framework for measuring fair value under GAAP and enhance disclosures about fair value measurements. We adopted the new standards with respect to non-financial assets and non-financial liabilities as of January 1, 2009, which did not have a material effect on our results of operations, financial position or cash flows; however, adoption may impact measurements of asset impairments and asset retirement obligations if they occur in the future.

Determining Fair Value in Inactive Markets — Effective for interim and annual periods beginning after June 15, 2009, GAAP established new accounting standards for determining fair value when the volume and level of activity for the asset or liability have significantly decreased and the identifying transactions are not orderly. The new standards apply to all fair value measurements when appropriate. Among other things, the new standards:

- affirm that the objective of fair value, when the market for an asset is not active, is the price that would be received in a sale of the asset in an orderly transaction;
- clarify certain factors and provide 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;
- provide that a transaction for an asset or liability may not be presumed to be distressed (not orderly) simply because there has been a significant decrease in the volume and level of activity for the asset or liability, rather, a company must determine whether a transaction is not orderly based on the weight of the evidence, and provide a non-exclusive list of the evidence that may indicate that a transaction is not orderly; and
- require disclosure in interim and annual periods of the inputs and valuation techniques used to measure fair value and any change in valuation technique (and the related inputs) resulting from the application of the standard, including quantification of its effects, if practicable.

These new accounting standards must be applied prospectively and retrospective application is not permitted. We adopted these new standards as of June 30, 2009, which resulted in a clarification of existing accounting guidance with no change to our accounting policies and had no effect on our results of operations, cash flows or financial position. See Note 7 for disclosure of our fair value measurements.

Interim Disclosures About Fair Value of Financial Instruments — Effective for interim and annual periods ending after June 15, 2009, GAAP established new disclosure requirements for the fair value of financial instruments in both interim and annual financial statements. Previously, the disclosure was only required annually. We adopted the new requirements as of June 30, 2009, which resulted in no change to our accounting policies, and had no effect on our results of operations, cash flows or financial position, but did result in the addition of interim disclosure of the fair values of our financial instruments. See Note 6 for disclosure of the fair value of our debt.

Noncontrolling Interests in Consolidated Financial Statements — Effective for interim and annual periods beginning after December 15, 2008, GAAP established new accounting standards and disclosure requirements for noncontrolling 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 a controlling financial interest in its subsidiary. In addition, the new standards established principles for valuation of retained noncontrolling equity investments and measurement of gain or loss when a subsidiary is deconsolidated as well as disclosure requirements to clearly identify and distinguish between interests of the parent and the interests of the noncontrolling owners. We adopted these new standards as of January 1, 2009, which did not have a material impact on our results of operations, financial position or cash flows; however, adoption did result in the reclassification of minority interest to noncontrolling interest on our Consolidated Condensed Balance Sheets and Statements of Operations.

Disclosures About Derivative Instruments and Hedging Activities — Effective for interim and annual periods beginning after November 15, 2008, GAAP established enhanced disclosure requirements relating to an entity's derivative and hedging activities to enable investors to better understand their effects on the entity's financial position, financial performance, and cash flows. We adopted the new disclosure requirements as of January 1, 2009. Adoption resulted in additional disclosures related to our derivatives and hedging activities including additional disclosures regarding our objectives for entering into derivative transactions, increased balance sheet and financial performance disclosures, volume information and credit enhancement disclosures. See Note 8 for our derivative disclosures.

Disclosures About Credit Derivatives and Certain Guarantees — Effective for interim and annual periods beginning after November 15, 2008, GAAP established enhanced disclosure requirements 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. We adopted the enhanced disclosure requirements as of January 1, 2009. Currently, we do not have instruments that meet the requirements for additional disclosure, and adoption of the new requirements did not have any impact on our results of operations, cash flows or financial position.

Subsequent Events — Effective for interim and annual periods ending after June 15, 2009, GAAP established general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The new requirements do not change the accounting for subsequent events; however, they do require disclosure, on a prospective basis, of the date an entity has evaluated subsequent events. We adopted these new requirements as of June 30, 2009, which had no impact on our results of operations, financial condition or cash flows. We have evaluated subsequent events up to the time of issuance of this Report to the SEC on October 29, 2009.

Consolidation of Variable Interest Entities — Effective for interim and annual periods beginning after November 15, 2009, with earlier application prohibited, GAAP amends the current accounting standards for determining which enterprise has a controlling financial interest in a VIE and amends guidance for determining whether an entity is a VIE. The new standards will also add reconsideration events for determining whether an entity is a VIE and will require ongoing reassessment of which entity is determined to be the VIE's primary beneficiary as well as enhanced disclosures about the enterprise's involvement with a VIE. We are currently assessing the future impact these new standards will have on our results of operations, financial position or cash flows. See Note 3 for a discussion of our VIEs.

2. Property, Plant and Equipment, Net

As of September 30, 2009, and December 31, 2008, the components of property, plant and equipment were stated at cost less accumulated depreciation as follows (in millions):

	September 30, 2009	December 31, 2008
Buildings, machinery and equipment	$ 13,369	$ 13,360
Geothermal properties	1,042	979
Other	238	258
	14,649	14,597
Less: Accumulated depreciation	(3,198)	(2,932)
	11,451	11,665
Land	73	76
Construction in progress	159	167
Property, plant and equipment, net	$ 11,683	$ 11,908

We are in the process of reviewing our accounting policies related to depreciation including our estimates of useful lives and whether other depreciation methods allowed under GAAP may be preferable. Potential changes in depreciation methods being reviewed primarily include, but are not limited to, changing from composite depreciation to component depreciation for a portion of our assets, and changing our Geysers Assets depreciation from the units of production method to the straight line method. In addition, we have recently completed a depreciable life study of our power plants and we are assessing whether an extension of the depreciable lives of our power plants would be appropriate. While management's analysis is not yet complete, we anticipate that it will be finalized during the fourth quarter of 2009. If we determine that other depreciation methods and useful lives are appropriate, we expect to change our accounting methods and useful lives to the other methods, and anticipate that we would account for any such changes on a prospective basis as changes in estimates in accordance with GAAP. Because we have not completed our analysis, we are currently unable to estimate the impact any changes could have on our future financial statements. However, such changes, if any, could be material to future depreciation expense.

3. Variable Interest Entities and Unconsolidated Investments

We consolidate all VIEs where we have determined that we are the primary beneficiary. This determination is made at the inception of our involvement with the VIE and, in accordance with GAAP, is updated only in response to a reconsideration event. Beginning on January 1, 2010, new accounting standards will require us to perform an ongoing reassessment of whether we continue to be the primary beneficiary. 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 of 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, an equity interest, or a portion of the future cash flows generated from an asset. For these VIEs, we determined at the time we entered into the contractual arrangement that consolidation was appropriate because exercise of the option was considered unlikely or would not provide the majority of the risk or reward from the project.

- *Consolidated Subsidiaries with Project Debt* — Certain of our subsidiaries have project debt that contains provisions which we have determined create variability. We retain ownership and absorb the full risk of loss and potential for reward once the project debt is paid in full. Actions by the lender to assume control of collateral can occur only under limited circumstances such as upon the occurrence of an event of default, which we have determined to be unlikely. Accordingly, we are the primary beneficiary of these VIEs. See Note 6 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 are deemed to be a form of subordinated financial support and thus constitute a VIE. 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 tables below detail the assets and liabilities (excluding intercompany balances which are eliminated in consolidation) for our VIEs, combined by VIE classification, that were included in our Consolidated Condensed Balance Sheets as of September 30, 2009, and December 31, 2008 (in millions):

Condensed Combined VIE Assets and Liabilities

	September 30, 2009			
	Purchase Options	Project Debt	PPAs	Other
Assets:				
Current assets	$ 270	$ 347	$ 125	$ 178
Restricted cash, net of current portion	11	7	17	—
Property, plant and equipment, net	2,589	3,086	1,366	—
Other assets	80	57	26	—
Total assets(1)	$ 2,950	$ 3,497	$ 1,534	$ 178
Liabilities:				
Current liabilities	$ 132	$ 122	$ 37	$ 171
Long-term debt	1,092	1,950	10	—
Long-term derivative liabilities	7	8	—	—
Other liabilities	9	12	8	—
Total liabilities(1)	$ 1,240	$ 2,092	$ 55	$ 171

	December 31, 2008			
	Purchase Options	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(1)	$ 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)	$ 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 above VIEs include sale options that are held by us or purchase options held by others, some are for only a minority interest, some are only for a portion of a VIE's total assets and liabilities and some are only effective upon the occurrence of an event of default.

Unconsolidated VIEs and Investments

We do not consolidate OMEC, a VIE where we have determined that we are not the primary beneficiary. We also have a joint venture interest in Greenfield LP and a less-than-majority equity interest in Whitby where we do not have control and therefore do not consolidate. We account for these entities under the equity method of accounting and include our net equity interest in investments on our Consolidated Condensed Balance Sheets as we exercise significant influence over their operating and financial policies. Our equity interest in the net (income) loss from our unconsolidated VIE, joint venture and equity interest is recorded in (income) loss from unconsolidated investments in power plants.

At September 30, 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 September 30, 2009	September 30, 2009	December 31, 2008
OMEC	100%	$ 133	$ 98
Greenfield LP	50%	76	46
Whitby	50%	1	—
Total investments		$ 210	$ 144

The following details our (income) loss and distributions from unconsolidated investments in power plants for the three and nine months ended September 30, 2009 and 2008 (in millions):

	Three Months Ended September 30,			
	2009	2008	2009	2008
	(Income) Loss from Unconsolidated Investments in Power Plants		Distributions	
OMEC	$ 13	$ 9	$ —	$ —
Greenfield LP	(1)	9	—	—
RockGen	—	(5)	—	—
Whitby	1	10	—	3
Auburndale	—	179	—	—
Total	$ 13	$ 202	$ —	$ 3

	Nine Months Ended September 30,			
	2009	2008	2009	2008
	(Income) Loss from Unconsolidated Investments in Power Plants		Distributions	
OMEC	$ (13)	$ (6)	$ —	$ —
Greenfield LP	(11)	17	—	24
RockGen	—	(9)	—	—
Whitby	(3)	8	2	3
Auburndale	—	179	—	—
Total	$ (27)	$ 189	$ 2	$ 27

Our risk of loss related to our unconsolidated VIEs is limited to our investment balance and our operational risks during the period we operate OMEC. The debt on the books of our unconsolidated investments is not reflected on our Consolidated Condensed Balance Sheets. As of September 30, 2009, and December 31, 2008, equity method investee debt was approximately $829 million and $697 million, respectively.

OMEC — OMEC, an indirect wholly owned subsidiary, is the owner of the Otay Mesa Energy Center, a 608 MW natural gas-fired power plant in southern San Diego County, California. OMEC began commercial operations on October 3, 2009. OMEC has a ten-year tolling agreement with SDG&E. We do not consolidate OMEC as a result of a put option held by OMEC to sell the Otay Mesa Energy Center for $280 million to SDG&E, and a call option held by SDG&E to purchase the Otay Mesa Energy Center for $377 million at the end of the tolling agreement. We determined SDG&E has a greater variability of risk compared to us and we are not the primary beneficiary.

OMEC has a $377 million non-recourse project finance facility structured as a construction loan, which converts to a term loan within 30 days of commercial operation of the Otay Mesa Energy Center, and matures in April 2019. We expect the construction loan to convert to a term loan in the fourth quarter of 2009. Borrowings under the project finance facility are initially priced at LIBOR plus 1.5%. Once the construction loan converts to a term loan, the term loan will bear interest at LIBOR plus 1.25%. We contributed $11 million and nil during the three months ended September 30, 2009 and 2008, respectively, and $19 million and $9 million for the nine months ended September 30, 2009 and 2008, respectively, as an additional investment in OMEC.

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 term loan in the amount of CAD $648 million. Borrowings under the project finance facility bear interest at Canadian LIBOR plus 1.125% or Canadian prime rate plus 0.125%. We contributed nil for both the three and nine months ended September 30, 2009, and $6 million for both the three and nine months ended September 30, 2008, as an additional investment in Greenfield LP.

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

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

Auburndale — Auburndale was an unconsolidated subsidiary accounted for under the equity method of accounting for the period from August 21, 2008 through the date of its sale on November 21, 2008. Prior to August 21, 2008, we consolidated Auburndale as we determined that we were Auburndale's primary beneficiary. Pomifer, an unrelated party, held a preferred interest which entitled it to approximately 70% of Auburndale's cash distributions through 2013. Pomifer also held an option which, upon exercise, entitled Pomifer to an additional 20% of Auburndale's cash distributions through 2013, as well as certain drag-along rights that would require us to sell our remaining interest in Auburndale should Pomifer sell its interest in Auburndale. On August 21, 2008, Pomifer exercised its option to the additional 20% of cash distributions, which required us, under GAAP, to reconsider whether we remained Auburndale's primary beneficiary. We determined that we were no longer Auburndale's primary beneficiary and we deconsolidated Auburndale during the third quarter of 2008. On September 30, 2008, Pomifer notified us of their intent to exercise their drag-along rights. Accordingly, we determined that a sale of our remaining interest was probable. We compared our expected proceeds from such sale to the net book value of our interest in Auburndale at September 30, 2008, to determine if an impairment existed and, as a result, recorded an impairment loss of approximately $179 million, which is included in our (income) loss from unconsolidated investments in power plants on our Consolidated Condensed Statement of Operations for the three and nine months ended September 30, 2008. We subsequently sold our remaining interest in Auburndale on November 21, 2008.

Inland Empire Energy Center Put and Call Options — We hold a call option to purchase the Inland Empire Energy Center development project (a 775 MW natural gas-fired power plant located in California) from GE that may be exercised between years 7 and 14 of the life of the power plant. GE holds a put option whereby they can require us to purchase the power plant, if certain plant performance criteria are met during year 15 of the life of the power plant. We determined that we were not the primary beneficiary of the Inland Empire power plant as we do not absorb the majority of the risk of loss associated with the project due to factors including, but not limited to, the fact that GE will continue to manage and fully fund the operation of the power plant. Additionally, if we purchase the power plant under the call or put options, GE will continue to provide critical plant maintenance services throughout the remaining estimated useful life of the power plant.

Significant Subsidiary — OMEC met the criteria of a significant subsidiary as defined under SEC guidelines at December 31, 2008 based upon the relationship of our equity income from our investment in this subsidiary to our consolidated net income before income taxes. The Condensed Statements of Operations for OMEC for the three and nine months ended September 30, 2009 and 2008, are set forth below (in millions):

OMEC
Condensed Statements of Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues[1]	$ —	$ —	$ —	$ —
Operating expenses	1	—	3	—
Loss from operations	(1)	—	(3)	—
Interest (income) expense[2]	11	9	(22)	(6)
Other (income) expense, net	1	—	6	—
Net income (loss)	$ (13)	$ (9)	$ 13	$ 6

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(1) OMEC began commercial operations on October 3, 2009.
(2) Interest (income) expense is the result of unrealized mark-to-market (gains) losses from interest rate swap contracts.

4. 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 by CER Generation LLC of certain liabilities. We recorded a pre-tax gain of approximately $63 million in reorganization items on our Consolidated Condensed Statement of Operations for the nine months ended September 30, 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 by First Energy Generation Corp. of certain liabilities. We recorded a pre-tax gain of approximately $136 million in reorganization items on our Consolidated Condensed Statement of Operations for the nine months ended September 30, 2008.

On August 21, 2008, Pomifer exercised its purchase option to purchase additional cash distributions of 20% through 2013 from Auburndale as further described in Note 3. On September 30, 2008, we received notice that Pomifer had entered into an asset purchase agreement with a third party and that Pomifer intended to exercise its drag-along rights to sell 100% of Auburndale. We recorded an impairment loss of approximately $179 million based upon the anticipated sales proceeds. We sold our remaining interest in Auburndale on November 21, 2008.

The sales of the Hillabee and Fremont development projects and the sale of Auburndale 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.

5. Comprehensive Income (Loss)

Comprehensive income (loss) includes our net income, 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 and nine months ended September 30, 2009 and 2008 (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income	$ 237	$ 135	$ 189	$ 118
Other comprehensive income (loss):				
Gain (loss) on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income	(154)	745	156	173
Reclassification adjustment for cash flow hedges realized in net income	(108)	119	(293)	141
Foreign currency translation gain (loss)	2	(3)	3	(9)
Income tax benefit (expense)	15	(97)	42	(101)
Comprehensive income (loss)	(8)	899	97	322
Add: Comprehensive loss attributable to the noncontrolling interest	1	1	3	1
Comprehensive income (loss) attributable to Calpine	$ (7)	$ 900	$ 100	$ 323

6. Debt

Our debt at September 30, 2009, and December 31, 2008, was as follows (in millions):

	September 30, 2009	December 31, 2008
First Lien Credit Facility	$ 5,875	$ 6,645
Commodity Collateral Revolver	100	100
Project financing	1,568	1,525
CCFC New Notes	957	—
CCFC Old Notes and CCFC Term Loans	—	778
Preferred interests	25	335
Notes payable and other borrowings	254	356
Capital lease obligations	706	733
Total debt	9,485	10,472
Less: Current maturities	421	716
Debt, net of current portion	$ 9,064	$ 9,756

First Lien Credit Facility — As of September 30, 2009, and December 31, 2008, our primary debt facility was the First Lien Credit Facility. The First Lien Credit Facility includes approximately $6.0 billion of senior secured term loans, a $1.0 billion senior secured revolver, and, subject to market conditions, the ability under an "accordion" provision to raise up to $2.0 billion of incremental senior secured term loans in order to repay or redeem secured debt, secured lease obligations or preferred securities of our subsidiaries.

As of September 30, 2009, under the First Lien Credit Facility, we had approximately $5.9 billion outstanding under the term loan facilities and $211 million of letters of credit issued against the revolver. On September 28, 2009 we repaid $725 million previously drawn under our First Lien Credit Facility revolver from cash on hand. Borrowings of term loans under the First Lien 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. First Lien Credit Facility term loans require quarterly payments of principal equal to 0.25% of the original principal amount of First Lien Credit Facility term loans. The First Lien Credit Facility matures on March 29, 2014.

The obligations under the First Lien 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 certain of the guarantors. The obligations under the First Lien Credit Facility are also secured by a pledge of the equity interests of the direct subsidiaries of certain of the guarantors, subject to certain exceptions, including exceptions for equity interests in foreign subsidiaries, existing contractual prohibitions and prohibitions under other legal requirements. The First Lien Credit Facility contains restrictions, including limiting our ability to, among other things:

- incur additional indebtedness and issue certain stock;
- make prepayments on or purchase certain 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 First Lien Credit Facility for non-guarantors (including foreign subsidiaries);
- make certain investments;
- create or incur liens;
- 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;
- pay dividends or make other distributions from certain of our subsidiaries up to Calpine Corporation;
- make capital expenditures beyond specified limits;
- engage in certain business activities;
- enter into certain transactions with our affiliates; and
- acquire power plants or other businesses.

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

2009 Financing Activities

Amendment of First Lien Credit Facility and Issuance of First Lien Notes due 2017 — We executed the First Amendment to Credit Agreement and Second Amendment to Collateral Agency and Intercreditor Agreement dated as of August 20, 2009, which amended both the First Lien Credit Facility Credit Agreement and the First Lien Credit Facility Collateral Agency and Intercreditor Agreement. The amendment provides additional flexibility with our capital structure and First Lien Credit Facility by granting us the option, subject to certain conditions, to buy back debt at a discount using cash on hand via an auction process; to offer first lien bonds in exchange for or to retire First Lien Credit Facility term loans; to issue up to $2.0 billion of first lien bonds in lieu of issuing first lien term loans under the accordion provision of the First Lien Credit Facility; and to extend all or a portion of the revolver and term loan maturities, on revised terms, subject to acceptance by applicable lenders. In addition, the amendment provides for the aggregation of various investment and capital expenditure baskets for covenant purposes. In connection with the amendment, we recorded approximately $5 million in new deferred financing costs on our Consolidated Condensed Balance Sheet.

We subsequently issued approximately $1.2 billion aggregate principal amount of First Lien Notes in a private placement on October 21, 2009. We received no net cash proceeds from the transaction. The offer and sale of the First Lien Notes was consummated as a permitted debt exchange pursuant to the First Lien Credit Facility in exchange for a like principal amount of First Lien Credit Facility term loans. Upon their exchange for First Lien Notes, such term loans were canceled and may not be redrawn. The First Lien Notes bear interest at 7.25% per annum payable on April 15 and October 15 of each year, beginning on April 15, 2010. The First Lien Notes will mature on October 15, 2017; however, among other things, prior to October 15, 2012, we may redeem up to 35% of the aggregate principal amount of the First Lien Notes with the net cash proceeds of certain equity offerings, at a price equal to 107.25% of the aggregate principal amount thereof, plus accrued and unpaid interest. Beginning on October 15, 2013, we may redeem all or a portion of the First Lien Notes at a premium as defined in the indenture governing the First Lien Notes, plus accrued and unpaid interest. The First Lien Notes are guaranteed by each of our current and future domestic subsidiaries that is a borrower or guarantor under our First Lien Credit Facility and the First Lien Notes rank equally in right of payment with all of our and the guarantors' other existing and future senior indebtedness, and will be effectively subordinated in right of payment to all existing and future liabilities of our subsidiaries that do not guarantee the First Lien Notes. The First Lien Notes are secured equally and ratably with indebtedness under our First Lien Credit Facility by a first-priority lien, subject to certain exceptions and permitted liens, on substantially all of our and certain of the guarantors' existing and future assets.

Subject to certain qualifications and exceptions, the First Lien Notes will, among other things, limit our ability and the ability of the guarantors to:

- incur or guarantee additional first lien indebtedness;
- enter into commodity hedge agreements
- enter into sale and leaseback transactions;
- create or incur liens; and
- consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries on a combined basis.

In connection with the issuance of the First Lien Notes, we expect to record approximately $26 million in debt extinguishment costs related to the retirement of the term loans under the First Lien Credit Facility and we also expect to record approximately $20 million in new deferred financing costs on our Consolidated Condensed Balance Sheet in the fourth quarter of 2009. Additionally, we expect that we will record approximately $11 million in additional interest expense during the fourth quarter of 2009 recognizing the fair value of the interest rate swaps hedging the variable interest rates on the retired First Lien Credit Facility term loans that will no longer qualify as cash flow hedges. At September 30, 2009, the fair value of these interest rate swaps was recorded in AOCI.

CCFC Refinancing — On May 19, 2009, our wholly owned subsidiaries, CCFC and CCFC Finance, issued $1.0 billion in aggregate principal amount of CCFC New Notes in a private placement. Interest on the CCFC New Notes accrues at the rate of 8.0% per annum and is payable semi-annually in arrears on each June 1 and December 1, commencing on December 1, 2009. The CCFC New Notes, which mature on June 1, 2016, are guaranteed by two of CCFC's subsidiaries. The CCFC New Notes and the related guarantees are secured, subject to certain exceptions and permitted liens, by all real and personal property of CCFC and CCFC's material subsidiaries (including the CCFC Guarantors), consisting primarily of six natural gas power plants as well as the equity interests in CCFC and the CCFC Guarantors. The CCFC New Notes are not guaranteed by Calpine Corporation and are without recourse to Calpine Corporation or any of our other non-CCFC or CCFC

Finance subsidiaries or assets. The net proceeds received of $939 million, together with CCFC cash on hand of $271 million, were used to:

- repay the $364 million outstanding under the CCFC Term Loans on May 19, 2009;
- redeem the $415 million outstanding principal amount of CCFC Old Notes on June 18, 2009;
- distribute $327 million to CCFC's indirect parent, CCFCP, which was used by CCFCP to redeem its $300 million CCFCP Preferred Shares on or before July 1, 2009; and
- in each case, pay any interest, prepayment penalties and other amounts due through the date of such repayment or redemption.

In connection with the CCFC Refinancing, we recorded $16 million and $49 million in debt extinguishment costs for the three and nine months ended September 30, 2009, respectively. Debt extinguishment costs recorded for the three months ended September 30, 2009 related to prepayment penalties and the write-off of unamortized deferred financing costs for the CCFCP Preferred Shares that were redeemed on July 1, 2009. Debt extinguishment costs for the nine months ended September 30, 2009 are comprised of $7 million from the write-off of unamortized deferred financing costs and unamortized debt discount and $24 million of prepayment penalties related to redemption of the CCFC Old Notes, and $2 million from the write-off of unamortized deferred financing costs and unamortized debt discount and $16 million related to prepayment penalties related to the redemption of the CCFCP Preferred Shares.

We also recorded approximately $21 million in new deferred financing costs on our Consolidated Condensed Balance Sheet upon closing the CCFC Refinancing.

Other — On August 13, 2009, we terminated $200 million of the remaining availability under the Commodity Collateral Revolver in accordance with its terms as energy commodity prices were not expected to exceed stated thresholds in the near future and it was considered unlikely that any of the $200 million remaining availability would be available to us. The $100 million currently outstanding under the Commodity Collateral Revolver will mature on July 8, 2010.

On January 21, 2009, Deer Park, our indirect wholly owned subsidiary, closed on $156 million of senior secured credit facilities, which include a $150 million term facility and a $6 million letter of credit facility. Proceeds received were used to settle an existing commodity contract of approximately $79 million, pay financing and legal fees of approximately $8 million and fund approximately $22 million in restricted cash. The remainder was distributed to Calpine Corporation for general corporate purposes. The senior term loan facility matures on January 21, 2012, and bears interest of LIBOR plus 3.5% or base rate plus 2.5% at Deer Park's option.

Letter of Credit Facilities — The table below represents amounts outstanding under our letter of credit facilities as of September 30, 2009, and December 31, 2008 (in millions):

	September 30, 2009	December 31, 2008
First Lien Credit Facility	$ 211	$ 259
Calpine Development Holdings, Inc.	148	148
Knock-in Facility[1]	—	50
Various project financing facilities	104	99
Total	$ 463	$ 556

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(1) The Knock-in Facility matured on June 30, 2009, and is no longer available.

Fair Value of Debt

We record our debt instruments based on contractual terms, net of any applicable premium or discount. We did not elect to apply the alternative GAAP provisions of the fair value option for recording financial assets and financial liabilities at fair value on our Consolidated Condensed Financial Statements. We measured the fair value of our debt instruments as of September 30, 2009, and December 31, 2008, using market information including credit default swap rates and historical default information, quoted market prices or dealer quotes for the identical liability when traded as an asset and discounted cash flow analyses based on our current borrowing rates for similar types of borrowing arrangements. The following table details the fair values and carrying values of our debt instruments as of September 30, 2009, and December 31, 2008 (in millions):

	September 30, 2009		December 31, 2008	
	Fair Value	**Carrying Value**	**Fair Value**	**Carrying Value**
First Lien Credit Facility	$ 5,317	$ 5,875	$ 4,812	$ 6,645
Commodity Collateral Revolver	90	100	85	100
Project financing	1,528	1,568	1,420	1,525
CCFC New Notes	1,015	957	—	—
CCFC Old Notes and CCFC Term Loans	—	—	727	778
Preferred interests	25	25	305	335
Notes payable and other borrowings	235	254	330	356
Total	$ 8,210	$ 8,779	$ 7,679	$ 9,739

7. Fair Value Measurements

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

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

Our level 2 fair value derivative instruments primarily consist of interest rate swaps and OTC power and natural gas forwards for which market-based pricing inputs are observable. Generally, we obtain our level 2 pricing inputs from markets such as the Intercontinental Exchange. In certain instances, our level 2 derivative instruments may utilize models to measure fair value. These models are primarily industry-standard models that incorporate various assumptions, including quoted interest rates, correlation, volatility, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Our level 3 fair value derivative instruments primarily consist of our OTC power and natural gas forwards and options where pricing inputs are unobservable, as well as other complex and structured transactions. Complex or structured transactions are tailored to our or our customers' needs and can introduce the need for internally-developed model inputs which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in level 3. Our valuation models may incorporate historical correlation information and extrapolate available broker and other information to future periods. In cases where there is no corroborating market information available to support significant model inputs, we initially use the transaction price as the best estimate of fair value. OTC options are valued using industry-standard models, including the Black-Scholes pricing model. At each balance sheet date, we perform an analysis of all instruments subject to fair value measurement and include in level 3 all of those whose fair value is based on significant unobservable inputs.

We utilize market data (such as pricing services and broker quotes) and assumptions that we believe market participants would use in pricing our assets or liabilities including assumptions about risks and the risks inherent to the inputs in the valuation technique. These inputs can be either readily observable, market corroborated or generally unobservable. The market data obtained from broker pricing services is evaluated to determine the nature of the quotes obtained and, where accepted as a reliable quote, used to validate our assessment of fair value; however, other qualitative assessments are used to determine the level of activity in any given market. We primarily apply the market approach and income approach for recurring fair value measurements and utilize what we believe to be the best available information. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observability of those inputs.

The primary factors affecting the fair value of our commodity derivative instruments at any point in time are the volume of open derivative positions (MMBtu and MWh); market price levels, principally for power and natural gas; our credit standing and that of our counterparties; and prevailing interest rates. Prices for power and natural gas are volatile, which can result in material changes in the fair value measurements reported in our financial statements in the future.

The fair value of our derivatives includes consideration of the credit standing of our counterparties and the impact of credit enhancements, if any. We have also recorded credit reserves in the determination of fair value based on our expectation of how market participants would determine fair value. Such valuation adjustments are generally based on market evidence, if available, or our best estimate.

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 approximate fair value.

The following tables present our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2009, and December 31, 2008, by level within the fair value hierarchy. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Assets and Liabilities with Recurring Fair Value Measures as of September 30, 2009			
	Level 1	**Level 2**	**Level 3**	**Total**
		(in millions)		
Assets:				
Cash equivalents(1)	$ 1,163	$ —	$ —	$ 1,163
Margin deposits(2)	341	—	—	341
Commodity instruments	1,839	367	114	2,320
Total assets	$ 3,343	$ 367	$ 114	$ 3,824
Liabilities:				
Margin deposits held by us posted by our counterparties(2)	$ 1	$ —	$ —	$ 1
Commodity instruments	1,883	201	53	2,137
Interest Rate Swaps	—	381	—	381
Total liabilities	$ 1,884	$ 582	$ 53	$ 2,519

	Assets and Liabilities with Recurring Fair Value Measures as of December 31, 2008			
	Level 1	**Level 2**	**Level 3**	**Total**
		(in millions)		
Assets:				
Cash equivalents(1)	$ 2,092	$ —	$ —	$ 2,092
Margin deposits(2)	653	—	—	653
Commodity instruments	3,263	634	160	4,057
Total assets	$ 6,008	$ 634	$ 160	$ 6,802
Liabilities:				
Margin deposits held by us posted by our counterparties(2)	$ 169	$ —	$ —	$ 169
Commodity instruments	3,515	475	55	4,045
Interest rate swaps	—	452	—	452
Total liabilities	$ 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 September 30, 2009, and December 31, 2008, we had cash equivalents of $685 million and $1,597 million included in cash and cash equivalents and $478 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 our counterparties and us 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 and nine months ended September 30, 2009 and 2008 (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Balance, beginning of period	$ 91	$ (649)	$ 105	$ (23)
Realized and unrealized gains (losses):				
Included in net income[1]	(5)	204	5	152
Included in OCI	1	719	13	280
Purchases, issuances and settlements, net	(8)	(15)	(34)	(147)
Transfers in and/or out of level 3[2]	(18)	(5)	(28)	(8)
Balance, end of period	$ 61	$ 254	$ 61	$ 254
Change in unrealized gains and (losses) relating to instruments still held as of September 30, 2009 and 2008[1]	$ (5)	$ 204	$ 5	$ 152

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(1) Includes $(4) million and $86 million recorded in operating revenues (for power contracts and Heat Rate swaps and options) and $(1) million and $118 million recorded in fuel and purchased energy expense (for natural gas contracts) for the three months ended September 30, 2009 and 2008, respectively, and includes $(1) million and $45 million recorded in operating revenues (for power contracts and Heat Rate swaps and options) and $6 million and $107 million recorded in fuel and purchased energy expense (for natural gas contracts) for the nine months ended September 30, 2009 and 2008, respectively, as shown on our Consolidated Condensed Statements of Operations.

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

8. Derivative Instruments

The following tables reflect the amounts that were recorded as derivative assets and liabilities on our Consolidated Condensed Balance Sheets at September 30, 2009, and December 31, 2008, for our derivative instruments (in millions):

	September 30, 2009		
	Interest Rate Swaps	Commodity Instruments	Total Derivative Instruments
Current derivative assets	$ —	$ 2,032	$ 2,032
Long-term derivative assets	—	288	288
Total derivative assets	$ —	$ 2,320	$ 2,320
Current derivative liabilities	$ 211	$ 1,886	$ 2,097
Long-term derivative liabilities	170	251	421
Total derivative liabilities	$ 381	$ 2,137	$ 2,518
Net derivative assets (liabilities)	$ (381)	$ 183	$ (198)

	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 the new accounting requirements related to disclosures about derivative instruments and hedging activities as of January 1, 2009, which required 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 as well as qualitative disclosures about our fair value amounts of gains and losses associated with derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements.

Commodity Instruments — We are exposed 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 by economically hedging a portion of the commodity price risk associated with 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 estimated generation and prevailing 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 act as economic hedges for our interest cash flow.

As of September 30, 2009, the maximum length of our PPAs extend approximately 24 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 3 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 in 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 probable of not 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 probable of not 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 are 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 carrying amount of the hedged item is adjusted by any gain or loss from the hedging instrument and remains 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, natural gas and interest rate transactions that primarily act as economic hedges to our asset portfolio, but either do not qualify as hedges under hedge accounting guidelines or qualify under the hedge accounting guidelines and the hedge accounting designation has not been elected, such as commodity futures, forwards, options, fixed for floating swaps and instruments that settle on power price to natural gas price relationships (Heat Rate swaps and options). Changes in fair value of derivatives not designated as hedging instruments are recognized currently in earnings as a component of operating revenues (for power contracts and Heat Rate swaps and options), fuel and purchased energy expense (for natural gas contracts) and interest expense (for interest rate swaps).

Derivatives Included on Our Consolidated Condensed Balance Sheet

The following table presents the fair values of our net derivative instruments recorded on our Consolidated Condensed Balance Sheet by hedge type and location at September 30, 2009 (in millions):

	Fair Value of Derivative Assets(1)	Fair Value of Derivative Liabilities(2)
Derivatives designated as cash flow hedging instruments:		
Interest rate swaps	$ —	$ 365
Commodity instruments	329	113
Total derivatives designated as cash flow hedging instruments	$ 329	$ 478
Derivatives designated in fair value hedging relationships:		
Commodity instruments, hedging instrument	$ —	$ 2
Commodity instruments, hedged item	2	—
Total derivatives designated in fair value hedging relationships	$ 2	$ 2
Derivatives not designated as hedging instruments:		
Interest rate swaps	$ —	$ 16
Commodity instruments	1,989	2,022
Total derivatives not designated as hedging instruments	$ 1,989	$ 2,038
Total derivatives	$ 2,320	$ 2,518

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(1) Included in derivative assets on our Consolidated Condensed Balance Sheet as of September 30, 2009.
(2) Included in derivative liabilities on our Consolidated Condensed Balance Sheet as of September 30, 2009.

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 September 30, 2009, the net forward notional buy (sell) position of our outstanding commodity and interest rate swap contracts that did not qualify under the normal purchases or normal sales exemption were as follows (in millions):

Derivative Instruments	Notional Volumes
Power (MWh)	(55)
Natural gas (MMBtu)	(59)
Interest rate swaps	$ 7,107

Certain of our derivative instruments contain credit-contingent provisions that require us to maintain our current credit rating or higher from each of the major credit rating agencies. If our credit rating were to be downgraded, it could require us to post additional collateral or could potentially allow our counterparty to request immediate, full settlement on certain derivative instruments in liability positions. The aggregate fair value of our derivative liabilities with credit-contingent provisions as of September 30, 2009, was $64 million for which we have posted collateral of $5 million by posting margin deposits or granted additional first priority liens on the assets currently subject to first priority liens under our First Lien Credit Facility. However, if our credit rating were downgraded, we estimate that any additional collateral would not be material and that no counterparty could request immediate, full settlement.

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.

The following table details the components of our total mark-to-market activity for both the net realized gain (loss) and the net unrealized gain (loss) recognized from our derivative instruments not designated as hedging instruments and the ineffectiveness related to our hedging instruments and where these components were recorded on our Consolidated Condensed Statements of Operations for the three and nine months ended September 30, 2009 and 2008 (in millions):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Realized gain (loss):				
Interest rate swaps(1)	$ (3)	$ (4)	$ (14)	$ (9)
Commodity instruments(2)(3)	1	(29)	(13)	(92)
Total realized gain (loss)	$ (2)	$ (33)	$ (27)	$ (101)
Unrealized gain (loss):				
Interest rate swaps(1)	$ 1	$ 4	$ 7	$ 6
Commodity instruments(3)	43	43	60	(22)
Total unrealized gain (loss)	$ 44	$ 47	$ 67	$ (16)
Total mark-to-market activity	$ 42	$ 14	$ 40	$ (117)

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(1) Included in interest expense on our Consolidated Condensed Statements of Operations.
(2) Balance includes a non-cash gain from amortization of prepaid power sales agreements of approximately $13 million and $33 million for the three and nine months ended September 30, 2008, respectively.
(3) Included in operating revenues and fuel and purchased energy expense on our Consolidated Condensed Statements of Operations.

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 the ineffectiveness related to our hedging instruments, and where these components were recorded on our Consolidated Condensed Statements of Operations for the three and nine months ended September 30, 2009 and 2008 (in millions):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Power contracts included in operating revenues	$ 17	$ 279	$ 8	$ 175
Natural gas contracts included in fuel and purchased energy expense	27	(265)	39	(289)
Interest rate swaps included in interest expense	(2)	—	(7)	(3)
Total mark-to-market activity	$ 42	$ 14	$ 40	$ (117)

The following table details the effect of our net derivative instruments that qualified for hedge accounting treatment on our Consolidated Condensed Statements of Operations, OCI and AOCI for the three and nine months ended September 30, 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)	
	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Interest rate swaps	$ (17)	$ 70	$ (60)(1)	$ (152)(1)	$ —	$ —
Commodity instruments	(245)	(207)	168(2)	445(2)	—(2)(3)	—(2)(3)
Total	$ (262)	$ (137)	$ 108	$ 293	$ —	$ —

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(1) Included in interest expense on our Consolidated Condensed Statements of Operations.
(2) Included in operating revenues and fuel and purchased energy expense on our Consolidated Condensed Statements of Operations.
(3) The ineffective portion of gains reclassified from AOCI into income on commodity hedging instruments was $1 million and $6 million for the three and nine months ended September 30, 2008, respectively.

Assuming constant September 30, 2009 power and natural gas prices and interest rates, we estimate that pre-tax net losses of $46 million would be reclassified from AOCI into earnings during the next 12 months as the hedged transactions settle; however, the actual amounts that will be reclassified will likely vary based on changes in natural gas and power prices as well as interest rates. Therefore, we are unable to predict what the actual reclassification from AOCI to earnings (positive or negative) will be for the next 12 months.

9. Use of Collateral

We use margin deposits, prepayments and letters of credit as credit support with and from our counterparties for commodity procurement and risk management activities. In addition, we have granted additional first priority liens on the assets currently subject to first priority liens under the First Lien Credit Facility as collateral under certain of our power and natural gas agreements that qualify as "eligible commodity hedge agreements" under the First Lien 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 First Lien 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 September 30, 2009, and December 31, 2008 (in millions):

	September 30, 2009	December 31, 2008
Margin deposits(1)	$ 341	$ 653
Natural gas and power prepayments	42	60
Total margin deposits and natural gas and power prepayments with our counterparties(2)	$ 383	$ 713
Letters of credit issued	$ 370	$ 455
First priority liens under power and natural gas agreements(3)	—	—
First priority liens under interest rate swap agreements	375	477
Total letters of credit and first priority liens with our counterparties	$ 745	$ 932
Margin deposits held by us posted by our counterparties(1)(4)	$ 1	$ 169
Letters of credit posted with us by our counterparties	182	95
Total margin deposits and letters of credit posted with us by our counterparties	$ 183	$ 264

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(1) Balances are subject to master netting agreements and presented on a gross basis on our Consolidated Condensed Balance Sheets.
(2) $363 million and $693 million were included in margin deposits and other prepaid expense on our Consolidated Condensed Balance Sheets at September 30, 2009 and December 31, 2008, respectively, and $20 million were included in other assets at September 30, 2009 and December 31, 2008.
(3) The fair value of our commodity derivatives collateralized by first priority liens included assets of $128 million and $201 million at September 30, 2009 and December 31, 2008, respectively; therefore, there is no collateral exposure at September 30, 2009 and December 31, 2008.
(4) Included in other current liabilities on our Consolidated Condensed Balance Sheets.

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

10. Income Taxes

As of September 30, 2009, our federal income tax reporting group was comprised primarily of two groups, CCFC and its subsidiaries, which we refer to as the CCFC group, and Calpine Corporation and its subsidiaries other than CCFC, which we refer to as the Calpine group. In 2005, CCFCP issued the CCFCP Preferred Shares, which resulted in the deconsolidation of the CCFC group for income tax purposes. On July 1, 2009, the CCFCP Preferred Shares were redeemed; however, CCFCP continues to be a partnership and therefore, the CCFC group remains deconsolidated from Calpine Corporation for federal income tax reporting purposes. As of September 30, 2009, the CCFC group did not have a valuation allowance recorded against its deferred tax assets, whereas the Calpine group continued to have a valuation allowance. For the three and nine months ended September 30, 2009, we used the effective rate method to determine both the CCFC and Calpine groups' tax provision; however, our income tax rates did not bear a customary relationship to statutory income tax rates primarily as a result of the impact of state income taxes, changes in unrecognized tax benefits, the Calpine group valuation allowance, adjustments to each group's federal taxable income for 2008 and prior years as a result of the finalization and filing of their respective 2008 federal income tax returns, and intraperiod tax allocations discussed below. For the three and nine months ended September 30, 2008, we determined that the effective rate method for computing the Calpine group 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 tax provision for the three and nine months ended September 30, 2008, based on an actual, or discrete, method. Under this method, we determined the Calpine group tax expense based upon actual results as if the interim period were an annual period. For the three and nine months ended September 30, 2008, the CCFC group utilized the effective rate method to determine its income tax expense. Under both of these methods, our imputed tax rate was (3)% and (145)% for the three months ended September 30, 2009 and 2008, respectively, and 8% and (103)% for the nine months ended September 30, 2009 and 2008, respectively.

Our consolidated income tax expense (benefit) was $(7) million and $(80) million for the three months ended September 30, 2009 and 2008, respectively, and $17 million and $(60) million for the nine months ended September 30, 2009 and 2008, respectively. Our income tax expense (benefit) included intraperiod tax allocation provisions of $15 million and $(101) million for the three months ended September 30, 2009 and 2008, respectively, and $42 million and $(101) million for the nine months ended September 30, 2009 and 2008, respectively, with an offsetting tax benefit (expense) to OCI.

GAAP requires that we consider all available evidence, both positive and negative, and tax planning strategies to determine whether, based on the weight of that evidence, a valuation allowance is needed to reduce the benefit of the deferred tax assets. Future realization of the tax benefit of an existing deductible temporary difference or carryforward ultimately depends on the existence of sufficient taxable income of the appropriate character within the carryback or carryforward periods available under the tax law. In prior periods, we provided a valuation allowance on certain federal, state and foreign tax jurisdiction deferred tax assets of the Calpine group to reduce the gross amount of these assets to the extent necessary to result in an amount that more likely than not will be 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 in prior periods; however, we have not released any additional previously recorded valuation allowance in 2009.

We remain subject to various audits and reviews by state taxing authorities; however, we do not expect these will have a material effect on our tax provision. Any NOLs we claim in future years to reduce taxable income could be subject to IRS examination regardless of when the NOLs occurred. Due to significant NOLs, any adjustment of state returns or federal returns from 2006 and forward would likely result in a reduction of deferred tax assets rather than a cash payment of income taxes.

As of September 30, 2009, we had unrecognized tax benefits of $98 million. If recognized, $50 million of our unrecognized tax benefits could impact the annual effective tax rate and $48 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 $17 million for income tax matters as of September 30, 2009 and if our unrecognized tax benefit is realized could also impact the annual effective tax rate. The amount of unrecognized tax benefits increased by $8 million for the nine months ended September 30, 2009, primarily as a result of an increase of approximately $10 million for withholding taxes and reductions of approximately $2 million for settlements with various state taxing authorities. We believe it is reasonably possible that a decrease of up to $4 million in unrecognized tax benefits could occur within the next 12 months, primarily related to penalties and interest for federal and foreign tax filings, as well as state tax liabilities, as a result of settlements with tax authorities.

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

To 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. As of the filing of this Report, neither circumstance was met. Accordingly, the transfer restrictions are not currently operative; however, they could become operative in the future if both of the foregoing events were to occur together and our Board of Directors were to elect 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 36% of our common stock at September 30, 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 which would meet one of the two circumstances, as described above, that would allow our Board of Directors to impose certain trading restrictions on our common stock.

11. Earnings 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 allowed as of the Effective Date, are unresolved. To the extent that any of the reserved shares remain undistributed upon resolution of the disputed claims, such shares will not be returned to us but rather will be distributed pro rata to claimants with allowed claims to increase their recovery. Therefore, pursuant to 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. We also include restricted stock units for which no future service is required as a condition to the delivery of the underlying common stock in our calculation of weighted average shares outstanding.

Reconciliations of the amounts used in the basic and diluted earnings per common share computations for the three and nine months ending September 30, 2009 and 2008, are:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
		(shares in thousands)		
Diluted weighted average shares calculation:				
Weighted average shares outstanding (basic)	485,736	485,076	485,619	485,027
Restricted stock awards	841	668	552	561
Employee stock options	8	—	—	—
Weighted average shares outstanding (diluted)	486,585	485,744	486,171	485,588

We excluded the following potentially dilutive securities from our calculation of diluted earnings per common share for the three and nine months ended September 30, 2009 and 2008:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(shares in thousands)			
Restricted stock awards(1)	—	1	—	—
Employee stock options(1)	13,203	8,860	13,115	5,407
Common stock warrants(1)(2)	—	29,519	—	34,160

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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 GAAP.

(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.

12. Stock-Based Compensation

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.

The equity awards granted under the Calpine Equity Incentive Plans include both graded and cliff vesting options which vest over periods between one and five years, contain contractual terms of seven and ten years and are subject to forfeiture provisions under certain circumstances, including termination of employment prior to vesting. 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 nine months ended September 30, 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.

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 and restricted stock units, we use our closing stock price on the date of grant, or the last trading day preceding the grant date for restricted stock granted on non-trading days, as the fair value for measuring compensation expense. Stock-based compensation expense is recognized over the period in which the related employee services are rendered. The service period is generally presumed to begin on the grant date and end when the equity award is fully vested. We use the graded vesting attribution method to recognize fair value of the equity award over the service period. For example, the graded vesting attribution method views one three-year option grant with annual graded vesting as three separate sub-grants, each representing 33 1/3% of the total number of stock options granted. The first sub-grant vests over one year, the second sub-grant vests over two years and the third sub-grant vests over three years. A three-year option grant with cliff vesting is viewed as one grant vesting over three years.

Stock-based compensation expense recognized was $8 million and $17 million for the three months ended September 30, 2009 and 2008, respectively, and $30 million and $36 million for the nine months ended September 30, 2009 and 2008, respectively. We did not record any tax benefits related to stock-based compensation expense in any period as we are not benefiting from a significant portion of our deferred tax assets, including deductions related to stock-based compensation expense. In addition, we did not capitalize any stock-based compensation expense as part of the cost of an asset for the three and nine months ended September 30, 2009 and 2008. At September 30, 2009, there was unrecognized compensation cost of $34 million related to options, $14 million related to restricted shares and nil related to restricted stock units, which is expected to be recognized over a weighted average period of 2.1 years for options, 2.0 years for restricted shares and 0.6 years for restricted stock units. 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 nine months ended September 30, 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	911,500	$ 9.42		
Exercised	—	$ —		
Forfeited	225,889	$ 17.65		
Expired	195,576	$ 17.28		
Outstanding – September 30, 2009	13,330,789	$ 19.08	6.8	$ 2
Exercisable – September 30, 2009	4,139,940	$ 18.83	7.2	$ —
Vested and expected to vest – September 30, 2009	13,132,612	$ 19.15	6.8	$ 2

There were no employee stock options exercised during the nine months ended September 30, 2009 and 2008.

The fair value of options granted during the nine months ended September 30, 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 – 6.5	5.0 – 6.1
Risk-free interest rate(2)	2.3 – 2.9%	2.7 – 3.3%
Expected volatility(3)	60.1 – 73.0%	35.9 – 48.2%
Dividend yield(4)	—	—
Weighted average grant-date fair value (per option)	$ 5.66	$ 6.48

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(1) Expected term calculated using the simplified method prescribed by the SEC.
(2) Zero Coupon U.S. Treasury rate or equivalent based on expected term.
(3) For the nine months ended September 30, 2009, we calculated volatility using the implied volatility of our exchange traded stock options. For the nine months ended September 30, 2008, we calculated volatility using the weighted average implied volatility of our industry peers' exchange traded stock options.
(4) We are currently prohibited under the First Lien Credit Facility and certain of our other debt agreements from paying any cash dividends on our common stock.

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 nine months ended September 30, 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	1,468,616	$ 9.49
Forfeited	204,435	$ 14.03
Vested	898,750	$ 16.64
Nonvested – September 30, 2009	2,107,673	$ 11.96

The total fair value of our restricted stock and restricted stock units that vested during the nine months ended September 30, 2009 and 2008, was $8 million and $3 million, respectively.

13. 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 440 million shares have been distributed to holders of allowed unsecured claims and approximately 45 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.

Reorganization Items — Reorganization items represent the direct and incremental costs related to our Chapter 11 cases. These include professional and trustee 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. We expect to continue to pay professional and trustee fees related to our Chapter 11 cases through 2009 and thereafter until the claims resolution process is completed and our Chapter 11 case is formally dismissed by the U.S. Bankruptcy Court.

The table below lists the significant components of reorganization items for the three and nine months ended September 30, 2009 and 2008 (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Provision for expected allowed claims	$ (5)	$ (1)	$ (3)	$ (55)
Professional and trustee fees	(3)	4	1	80
Gains on asset sales	—	(1)	—	(204)
Gain on reconsolidation of the Canadian Debtors and other deconsolidated foreign entities	—	(4)	—	(69)
Interest (income) on accumulated cash	—	—	—	(7)
Other	—	—	—	(8)
Total reorganization items	$ (8)	$ (2)	$ (2)	$ (263)

Provision for expected allowed claims — During the nine months ended September 30, 2008, our provision for expected allowed claims consisted primarily of a $62 million credit related to the settlement of claims with the Canadian Debtors and other deconsolidated foreign entities.

Gains on asset sales, net of equipment impairments — Represents gains on the sales of the Hillabee and Fremont development projects for the nine months ended September 30, 2008. See Note 4 for further discussion of our sales of Hillabee and Fremont.

14. Commitments and Contingencies

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 U.S. Debtors and the Canadian 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 13 for information regarding our emergence from our Chapter 11 and our 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. 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 to the extent there was insurance coverage available to Calpine Corporation.

The parties attended mediation on June 1, 2009 and settlement discussions continued thereafter. On October 12, 2009, the parties executed a Stipulation of Settlement, which settled the matter for $43 million contingent upon court approval. Pursuant to the December 19, 2007 agreement, Calpine Corporation’s portion of the settlement is to be satisfied solely from applicable insurance coverage. Preliminary approval of the class action settlement was granted by Santa Clara Superior Court on October 26, 2009. A final approval hearing is expected to be scheduled in early 2010.

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 the Pit River Tribe 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 the BLM and the 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. The Pit River Tribe timely appealed the Court's December 22, 2008 order. 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. However, we have not yet proceeded with providing the necessary technical information to BLM which would allow it to commence preparing a programmatic environmental impact statement. The Pit River Tribe filed its appellate brief on August 21, 2009. The U.S. Department of Justice and Calpine filed their response briefs on September 22, 2009. The Pit River Tribe's reply brief was filed October 21, 2009. A hearing date for the appeal has not been set.

In addition, the Pit River Tribe 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 River 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 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. In addition, 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 that motion on August 27, 2008. The parties have briefed the merits of Mr. Felluss' appeal and the Second Circuit recently scheduled oral argument for November 10, 2009.

Environmental Matters

We are subject to complex and stringent environmental laws and regulations related to the operation of our power plants. On occasion, we may incur environmental fees, penalties and fines associated with the normal operation of our power plants. We do not, however, have environmental violations or other matters that would have a material impact on our financial condition, results of operations or cash flows or that would significantly change our operations of our power plants. A summary of our larger environmental matters are as follows:

Texas City and Clear Lake Environmental Matters. As part of an internal review of our Texas City and Clear Lake power plants, we determined that these power plants were in violation of the requirements of the Acid Rain Program found in 40 CFR Parts 72-78. These power plants were originally exempt from these provisions because each plant was a qualifying cogeneration power plant in operation before November 1990 with qualifying original PPAs in place. However, the PPAs expired in 2002 for our Texas City power plant and 1999 for our Clear Lake power plant. To remedy the violations, the power plants are required to retire the number of SO_2 emission allowances equal to actual SO_2 emitted since the expiration of the exemption and remit an excess emission fee for each ton of SO_2 emitted during the period of non-compliance. We self-reported the excess emissions to the TCEQ and the EPA, and paid the appropriate fees. Compliance agreements between each power plant and the TCEQ were executed on September 26, 2008, and limit enforcement by the TCEQ. The EPA does have authority and discretion to issue substantial fines that could be material; however, based on the circumstances and on consideration of recent cases addressed by the agencies involved, we do not believe that the maximum penalty will be assessed or that penalties, if any, resulting from these matters will have a material adverse effect on our business, financial condition or results of operations.

San Diego Air Pollution Control District. The San Diego Air Pollution Control District issued OMEC a notice of violation on August 28, 2009 for failing to install an auxiliary boiler required by the permit issued by the San Diego Air Pollution Control District. OMEC entered into a compliance agreement on September 18, 2009 under which it paid the San Diego Air Pollution Control District a civil penalty, made a contribution to the San Diego Air Pollution Control District's Air Quality Improvement Trust Fund, and agreed to install an auxiliary boiler by November 30, 2009 and to install control system software to reduce emissions occurring during gas turbine startup.

Other Contingencies

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.

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 are rejected are uncertain and would represent an unsecured bankruptcy claim with Lyondell. 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. The percentage of recovery on unsecured claims in the Lyondell bankruptcy is unknown at this time, but is expected to be low.

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

15. 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). We continue to evaluate the optimal manner in which we assess our performance including our segments and future changes may result.

Commodity Margin includes our power and steam revenues, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, RGGI compliance costs, and cash settlements from our marketing, hedging and optimization activities that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other 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 to include the allocation (based upon each regional segment's MWh) of revenues and expenses from our fuel management, TMG, certain non-region specific natural gas marketing and optimization and other corporate activities, which had formerly been separately reported as our "Other" segment. 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 period presentation. Financial data for our segments were as follows (in millions):

	Three Months Ended September 30, 2009					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Revenues from external customers	$ 912	$ 530	$ 238	$ 167	$ —	$ 1,847
Intersegment revenues	5	6	24	—	(35)	—
Total operating revenues	$ 917	$ 536	$ 262	$ 167	$ (35)	$ 1,847
Commodity Margin	$ 393	$ 187	$ 92	$ 96	$ —	$ 768
Add: Mark-to-market commodity activity, net and other revenue(1)	41	2	(4)	21	(12)	48
Less:						
Plant operating expense	99	35	27	18	17	196
Depreciation and amortization expense	49	27	17	16	(1)	108
Other cost of revenue(2)	18	6	3	10	(18)	19
Gross profit	268	121	41	73	(10)	493
Other operating expenses	31	14	8	3	—	56
Income from operations	237	107	33	70	(10)	437
Interest expense, net of interest income						195
Debt extinguishment costs and other (income) expense, net						20
Income before reorganization items and income taxes						222
Reorganization items						(8)
Income before income taxes						$ 230

	Three Months Ended September 30, 2008					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Revenues from external customers	$ 1,198	$ 1,433	$ 336	$ 223	$ —	$ 3,190
Intersegment revenues	15	92	75	3	(185)	—
Total operating revenues	$ 1,213	$ 1,525	$ 411	$ 226	$ (185)	$ 3,190
Commodity Margin	$ 372	$ 233	$ 95	$ 100	$ —	$ 800
Add: Mark-to-market commodity activity, net and other revenue(1)	(45)	188	3	(69)	(9)	68
Less:						
Plant operating expense	96	56	31	23	(8)	198
Depreciation and amortization expense	48	31	16	15	—	110
Other cost of revenue(2)	19	3	5	8	(9)	26
Gross profit (loss)	164	331	46	(15)	8	534
Other operating expenses	28	25	189	20	—	262
Income (loss) from operations	136	306	(143)	(35)	8	272
Interest expense, net of interest income						201
Debt extinguishment costs and other (income) expense, net						18
Income before reorganization items and income taxes						53
Reorganization items						(2)
Income before income taxes						$ 55

	Nine Months Ended September 30, 2009					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Revenues from external customers	$ 2,589	$ 1,386	$ 589	$ 431	$ —	$ 4,995
Intersegment revenues	22	59	79	13	(173)	—
Total operating revenues	$ 2,611	$ 1,445	$ 668	$ 444	$ (173)	$ 4,995
Commodity Margin	$ 994	$ 505	$ 233	$ 215	$ —	$ 1,947
Add: Mark-to-market commodity activity, net and other revenue(1)	120	(48)	2	37	(35)	76
Less:						
Plant operating expense	326	163	94	61	10	654
Depreciation and amortization expense	150	88	50	47	(5)	330
Other cost of revenue(2)	45	11	7	23	(28)	58
Gross profit	593	195	84	121	(12)	981
Other operating expenses	44	51	23	—	—	118
Income from operations	549	144	61	121	(12)	863
Interest expense, net of interest income						602
Debt extinguishment costs and other (income) expense, net						57
Income before reorganization items and income taxes						204
Reorganization items						(2)
Income before income taxes						$ 206

	Nine Months Ended September 30, 2008					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Revenues from external customers	$ 3,335	$ 3,123	$ 1,015	$ 496	$ —	$ 7,969
Intersegment revenues	40	212	169	15	(436)	—
Total operating revenues	$ 3,375	$ 3,335	$ 1,184	$ 511	$ (436)	$ 7,969
Commodity Margin	$ 965	$ 587	$ 208	$ 228	$ —	$ 1,988
Add: Mark-to-market commodity activity, net and other revenue(1)	(30)	114	6	(24)	(20)	46
Less:						
Plant operating expense	309	178	84	73	(8)	636
Depreciation and amortization expense	143	94	54	40	(2)	329
Other cost of revenue(2)	54	9	23	21	(19)	88
Gross profit	429	420	53	70	9	981
Other operating expenses	61	65	202	30	—	358
Income (loss) from operations	368	355	(149)	40	9	623
Interest expense, net of interest income						799
Debt extinguishment costs and other (income) expense, net						29
Loss before reorganization items and income taxes						(205)
Reorganization items						(263)
Income before income taxes						$ 58

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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.

(2) Excludes $1 million and nil of RGGI compliance costs for the three months ended September 30, 2009 and 2008, respectively, and $5 million and nil for the nine months ended September 30, 2009 and 2008, respectively, which were included as a component of Commodity Margin.

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 economically 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 77 operating power plants, with an aggregate generation capacity of approximately 24,795 MW and our net interest of about 400 MW in Russell City Energy Center in advanced development and the planned expansion of 120 MW to our Los Esteros power plant. 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), 15,570 MW of intermediate load capacity from our combined-cycle combustion turbines and 5,145 MW of peaking capacity from our simple-cycle combustion turbines and duct-fired capability.

We assess our business on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and other factors impacting supply and demand. Our reportable segments are West (including geothermal), Texas, Southeast and North (including Canada). In these segments we have an aggregate generation capacity of 7,854 MW in the West, 7,487 MW in Texas, 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.

Operational Developments

During 2009, we have continued to implement our strategy for excellence in operations and the optimization of our existing assets. We have made some notable achievements that are listed below:

- During the quarter, our plant operating personnel exceeded the first quartile performance for employee lost time incident rate for fossil fuel electric power generator companies with 1,000 or more employees, achieved high unit availability (over 97%) and disciplined cost controls.
- OMEC, located in San Diego, California achieved commercial operations on October 3, 2009, adding 608 MW in summer capacity to our fleet.
- Our customer origination focus has delivered several significant new transactions, including in California, amendments to existing PPAs extending the duration and quantity of those contracts and new PPAs, some of which must be approved by the CPUC.
- Under one of the new PPAs, we will modernize and upgrade our Los Esteros power plant to add 120 MW by converting it from simple-cycle (peaking) to combined-cycle technology, increasing the efficiency and environmental performance of the power plant.
- We successfully restructured and streamlined our power and commercial operations as well as our corporate functions to more effectively manage our business and reduce expenses.

Capital Management

We have opportunistically completed several financing transactions to improve our flexibility and management of our capital structure. Significant 2009 actions include, but are not limited to, the following:

- We amended our First Lien Credit Facility and related collateral agency and intercreditor agreement in several respects to give us greater flexibility, including allowing us to exchange First Lien Credit Facility term loans for First Lien Notes.
- On October 21, 2009, we issued approximately $1.2 billion aggregate principal amount of First Lien Notes in a private placement as a permitted debt exchange pursuant to the First Lien Credit Facility, which retired an aggregate principal amount of term loans under the First Lien Credit Facility equal to the aggregate principal amount of First Lien Notes issued. As a result of the issuance of the First Lien Notes, we were able to extend the maturities of approximately $1.2 billion in debt, at the same time converting it from a variable to a fixed interest rate.
- Our wholly owned subsidiaries, CCFC and CCFC Finance, issued $1.0 billion aggregate principal amount of CCFC New Notes in a private placement. The net proceeds were used to repay the CCFC Term Loans, CCFC Old Notes and CCFCP Preferred Shares. As a result of the CCFC Refinancing transactions, we were able to extend the maturities of approximately $1.0 billion of debt by several years, at the same time converting it from a variable to a fixed interest rate and lowering our effective interest rates.
- We closed on our Deer Park $156 million senior secured credit facilities, which included 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, fund additional restricted cash and for general corporate purposes.

Legislative and Regulatory Update

We are subject to complex and stringent energy, environmental and other governmental laws and regulations at the federal, state and local levels in connection with the development, ownership and operation of our power plants. 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. Such changes could have positive or negative impacts on our existing business. We are actively participating in these debates at the federal, regional and state levels. For a further discussion of the environmental and other governmental regulations that affect us, 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 June 26, 2009, the U.S. House of Representatives passed "The American Clean Energy and Security Act of 2009," a climate change and clean energy bill. The legislation includes, among other provisions:

- An economy-wide carbon cap-and-trade program that:

  i. sets reduction targets for carbon emissions from capped sources in several sectors of the economy, including the power sector, starting at a 3% reduction from 2005 levels by 2012, increasing to 17% by 2020, 42% by 2030 and 83% by 2050,
  ii. starts in 2012 for the power sector and establishes the point of regulation at the power plant,
  iii. distributes 85% of emissions allowances for free, with 35.85% going to the power sector, including 1.5% to eligible generation facilities with qualifying long-term power and steam sales contracts,
  iv. requires an auction of the remaining 15% of emissions allowances with the proceeds of such auctions distributed to low- and moderate-income families, and
  v. delegates authority to FERC to regulate the cash market in emissions allowances and offsets and to the CFTC to regulate the associated derivatives market.
- A federal energy efficiency and renewable electricity standard which requires retail electricity suppliers to meet the needs of a specific percentage of their load from renewable energy resources and electricity savings.

If this bill were to become law, we would have the obligation to obtain emissions allowances for the operation of our fossil-fuel power plants. While we expect the costs to acquire allowances to be a factor that will impact market price, there can be no assurance that market price will fully reflect these costs. With respect to our existing long-term steam and power contracts under which we would not be able to recover costs to acquire allowances from our customers, the bill allocates a pool of free allowances to generators with qualifying contracts to mitigate such costs. However, there can be no assurance there will be a sufficient number of free allowances in the pool to fully cover emissions related to generation under such contracts.

On October 23, 2009, draft climate change legislation entitled the Clean Energy Jobs and American Power Act, was released in the Senate. The legislation is similar to the House passed legislation, though its focus is primarily on climate change, not energy. The legislation sets reduction targets for carbon emissions of 20% by 2020 rather than the 17% included in The American Clean Energy and Security Act of 2009; distributes a substantial portion of emissions allowances for free, with some going to the power sector, including to eligible power plants with qualifying long-term power and steam sales contracts; requires an auction of 25% of emissions allowances with the proceeds dedicated for consumer protections and deficit reduction; states that there will be one regulatory body that has market oversight authority, though it does not specify which agency will have that authority; directs the administrator of the EPA to establish an incentives payment program that promotes generation projects that have lower GHG emissions; and provides grants for research and development for advanced natural gas-fired generation technology.

The Senate Environment and Public Works Committee commenced legislative hearings on October 27, 2009 with the stated goal of passing legislation out of the committee by the end of November. Although we cannot predict the effect and ultimate content of final climate change legislation and regulations, if any, on our business, we continue to monitor and actively participate in the process where we anticipate an impact on our business.

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 starting with mobile sources, and later including larger stationary sources such as power plants. 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.

In a separate case, on September 21, 2009 the U.S. Court of Appeals for the Second Circuit issued an order in *State of Connecticut, et al. v. American Electric Power Company Inc., et al.*, reversing a lower court's dismissal of two public nuisance claims filed by various states, municipalities and private entities against operators of coal-fired power plants. Plaintiffs argued that the power plant defendants contribute to global warming by emitting 650 million tons per year of carbon dioxide and these emissions are causing and will continue to cause serious harms affecting human health and natural resources. The lower court held that plaintiffs' claims presented a non-legal political question and dismissed the complaints. The Second Circuit vacated the lower court's ruling and remanded the cases to the lower court for further proceedings. On October 16, 2009, the U.S. Court of Appeals for the Fifth Circuit made a similar ruling, finding that private property owners may bring claims of public and private nuisance against GHG-emitting oil and chemical companies. We cannot predict at this time the outcome of these cases or what impact the precedent of these cases could have on our business.

Texas

The Sunset review process, implemented by the Texas Legislature in 1977, is the regular assessment of the need for a state agency to exist and to consider new and innovative changes to improve each agency's operations and activities. The Sunset process works by setting a date on which an agency will be abolished unless legislation is passed to continue its functions. The Sunset review process began in September for the PUCT and ERCOT. It is expected to be concluded by April 2010. The TCEQ review will begin in April 2010 and is scheduled to be completed by November 2010 when the compliance phase for all agencies will begin. We will monitor the Sunset review process of these entities and will seek to participate in these processes where we anticipate an impact on our business.

California

At the end of the California legislative session, the legislature passed a bill to increase the state's RPS to 33% by 2020. The governor of California vetoed the bill. In a separate move, the governor signed an executive order directing CARB under its authority granted by Assembly Bill 32 to adopt regulations consistent with a 33% RPS by 2020. Implementation details of the executive order are yet to be determined; however, it directs CARB to adopt regulations by July 31, 2010.

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 includes approximately $787.0 billion in federal tax cuts, expansion of unemployment benefits and other social welfare provisions, and increased domestic spending for education, healthcare and infrastructure, including the energy sector. Approximately $43.0 billion will be available for loans and investments into green energy technology and a number of other renewable energy incentives that can impact our growth and development, particularly our geothermal assets. Specifically, the Stimulus Bill:

- extends the placed-in-service deadline through 2013 for geothermal projects to qualify for “production tax credits”;
- allows geothermal developers to elect to receive a 30% “investment tax credit” in lieu of production tax credits with respect to certain “qualified property” placed in service during 2009 or 2010 (or, in certain cases, after 2010), or a cash grant in lieu of investment tax credits or production tax credits with respect to such qualified property (subject to satisfying certain procedural and other requirements mandated by recently-issued Department of Treasury guidance); and
- designates $6.0 billion in funds to serve as a loss reserve and source of funding for a federal loan guarantee program anticipated to backstop renewable energy project financing.

We expect that any new geothermal power plant development of our Geysers Assets will qualify for the 30% investment tax credit from the IRS, and our re-powering of our existing plants to qualify for the 10% investment tax credit.

Financial Regulatory Reform and Derivatives

In August 2009, the Obama Administration released draft financial regulatory reform language that, among other things, could significantly change how derivative markets and their participants are regulated. The House Financial Services Committee voted out a bill on October 15, 2009 to regulate OTC derivatives trading, and the House Agriculture Committee voted out a similar bill on October 21, 2009. The two committee bills must be combined and brought to the House floor for a vote. The stated goal is to have a House floor vote by late November. The regulatory reform topics related to derivatives being considered include, among other things: "standardized" OTC energy derivatives be traded on registered exchanges regulated by the CFTC, new and potentially higher capital and margin requirements, volume and position limits, increased regulation and supervision from the CFTC and the SEC, and additional business conduct, record-keeping and reporting requirements. The leadership of the relevant Senate committees has not yet made clear either their legislative priorities with respect to financial regulatory reform, or their anticipated schedule for hearings and markups. Although we cannot predict the effect and ultimate content of final derivatives legislation, if any, some of the new proposed regulatory requirements could make our hedging and optimization activities more difficult and more costly, which could have an adverse impact on our ability to hedge risks associated with our business. We intend to actively monitor and participate in this process where we anticipate an impact on our business.

Geothermal Operations

In 2009, as part of a joint private and federally funded geothermal technology research project, a company unrelated to us commenced deepening an existing geothermal well on a property neighboring our Geysers Assets and reportedly was attempting to drill into the hot, low or non-permeable base rock that underlies the existing geothermal steam reservoir at The Geysers to engineer or create a “multilayered heat extraction system” below the reservoir by injecting water under very high pressure, fracturing the rock. This process has spawned public and political concern regarding increased seismicity risk. As a consequence, in July 2009, the Department of Energy temporarily halted funding of its portion of that project pending further seismicity studies.

In addition, the Department of Energy and residents located near our Geysers Assets have expressed concern regarding induced seismicity associated with geothermal operations. In response to those concerns, it is possible that government entities or agencies will seek to more stringently regulate the exploration, development, and operation of geothermal facilities, including our Geysers Assets, in order to mitigate induced seismicity resulting from geothermal operations.

Results of Operations for the Three Months Ended September 30, 2009 and 2008

Below are the results of operations for the three months ended September 30, 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 period 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	$ 1,830	$ 2,960	$ (1,130)	(38) %
Mark-to-market activity(1)	12	218	(206)	(94)
Other revenue	5	12	(7)	(58)
Operating revenues	1,847	3,190	(1,343)	(42)
Cost of revenue:				
Fuel and purchased energy expense:				
Commodity expense	1,061	2,160	1,099	51
Mark-to-market activity(1)	(31)	162	193	#
Fuel and purchased energy expense	1,030	2,322	1,292	56
Plant operating expense	196	198	2	1
Depreciation and amortization expense	108	110	2	2
Other cost of revenue(2)	20	26	6	23
Total cost of revenue	1,354	2,656	1,302	49
Gross profit	493	534	(41)	(8)
Sales, general and other administrative expense	38	58	20	34
Loss from unconsolidated investments in power plants	13	202	189	94
Other operating expense	5	2	(3)	#
Income from operations	437	272	165	61
Interest expense	198	212	14	7
Interest (income)	(3)	(11)	(8)	(73)
Debt extinguishment costs	16	—	(16)	—
Other (income) expense, net	4	18	14	78
Income before reorganization items and income taxes	222	53	169	#
Reorganization items	(8)	(2)	6	#
Income before income taxes	230	55	175	#
Income tax benefit	(7)	(80)	(73)	(91)
Net income	237	135	102	76
Net loss attributable to the noncontrolling interest	1	1	—	—
Net income attributable to Calpine	$ 238	$ 136	$ 102	75

Operating Performance Metrics:	2009	2008	Change	% Change
MWh generated (in thousands)(3)	28,051	25,773	2,278	9 %
Average availability	97.1%	96.6%	0.5	1
Average total MW in operation	23,423	23,064	359	2
Average capacity factor, excluding peakers	60.7%	55.2%	5.5	10
Steam Adjusted Heat Rate	7,268	7,274	6	—

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\# Variance of 100% or greater

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

(2) Includes $1 million and nil of RGGI compliance costs for the three months ended September 30, 2009 and 2008, respectively, which is a component of Commodity Margin.

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

Commodity revenue, net of commodity expense, decreased $31 million for the three months ended September 30, 2009 compared to the same period in 2008, primarily due to a decrease in Commodity Margin in Texas of $46 million resulting from lower market spark spreads caused by lower natural gas prices partially offset by higher Market Heat Rates and higher average availability. The overall decrease was partially offset by an increase of $21 million in Commodity Margin in the West due to higher hedge prices and the higher Market Heat Rate component of spark spread where we had hedged the corresponding gas open position. In addition, Commodity Margin in the Southeast and North decreased $3 million and $4 million, respectively, for the three months ended September 30, 2009 compared to 2008.

Net unrealized mark-to-market activity primarily resulting from our portfolio hedging activities that did not qualify for hedge accounting decreased $13 million for the three months ended September 30, 2009, compared to the same period in 2008. The decrease in revenues from mark-to-market activity was primarily driven by the impact of 2008 where rapidly falling power prices resulted in a gain on our short hedge positions in operating revenues. Similarly, the decrease in expenses from mark-to-market activity was primarily driven by the impact of 2008 where rapidly falling natural gas prices resulted in losses on our long hedge positions in fuel and purchased energy expense.

Other revenue decreased for the three months ended September 30, 2009 compared to the same period in 2008, primarily related to a $4 million decrease in revenue from operation and maintenance contracts and a $1 million decrease in revenue from construction management projects completed in 2008.

Normal, recurring costs in plant operating expense decreased for the three months ended September 30, 2009 compared to the same period in 2008, after accounting for $15 million in reimbursements for insurance claims from prior periods that reduced expenses in the three months ended September 30, 2008.

Other cost of revenue decreased for the three months ended September 30, 2009 compared to the three months ended September 30, 2008, as a result of a decrease of $3 million related to the discontinuation of the amortization of other assets associated with the 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 spot market power prices in the third quarter of 2009 compared to the same period in 2008. The decrease was partially offset by an increase of $1 million in expenses related to RGGI compliance in the Northeast which was initiated in 2009.

Sales, general and other administrative expense decreased for the three months ended September 30, 2009 compared to the same period in 2008, due to a $9 million decrease in personnel costs and stock-based compensation expense resulting primarily from a lower headcount in 2009 as well as a $9 million decrease in legal and consulting expenses.

Our loss from unconsolidated investments in power plants decreased for the three months ended September 30, 2009 compared to the three months ended September 30, 2008, primarily due to an impairment loss of $179 million related to our equity interest in Auburndale recorded during the third quarter of 2008. Also contributing to the decrease was income from our investment in Greenfield LP of $1 million for the three months ended September 30, 2009, which is due to Greenfield LP achieving commercial operations in October 2008, compared to a loss of $9 million from interest rate hedging for the three months ended September 30, 2008.

Interest expense decreased for the three months ended September 30, 2009 compared to the three months ended September 30, 2008, primarily resulting from lower average interest rates on our variable rate debt due to a decrease in LIBOR over the same periods. The annualized effective interest rates on our consolidated debt, excluding the impacts of capitalized interest and unrealized mark-to-market gains (losses) on interest rate swaps, after amortization of deferred financing costs and debt discounts, were 7.7% and 8.7% for the three months ended September 30, 2009 and 2008, respectively. The decrease in interest expense was partially offset by the negative period over period impact of $30 million related to our interest rate swaps on our First Lien Credit Facility resulting from a decrease in LIBOR.

Interest income decreased for the three months ended September 30, 2009 compared to the three months ended September 30, 2008, largely resulting from lower average interest rates earned on our cash balances which were primarily invested in U.S. Treasury securities or government-backed securities for the three months ended September 30, 2009 compared to our cash balances primarily invested in institutional-backed money market accounts for the three months ended September 30, 2008.

Debt extinguishment costs increased for the three months ended September 30, 2009 compared to the same period in 2008, due to $16 million in debt extinguishment costs associated with the CCFCP Preferred Shares that were redeemed in July 2009.

Other (income) expense, net had a favorable variance primarily as a result of a $13 million loss incurred during the three months ended September 30, 2008 related to our settlement with Panda.

Reorganization items decreased for the three months ended September 30, 2009 compared to the three months ended September 30, 2008, primarily resulting from a credit of approximately $6 million related to a favorable settlement during the third quarter of 2009 from a disputed claim on a PPA contract that was terminated in January 2006.

For the three months ended September 30, 2009 we recorded an income tax benefit of $7 million compared to a benefit of $80 million for the three months ended September 30, 2008. Our 2009 income tax benefit was due to a $27 million benefit from the CCFC group partially offset by $15 million in expense of reversing intraperiod tax allocations and $5 million of other tax expense. In 2008, our income tax benefit included $101 million intraperiod tax allocation benefits resulting from 2008 OCI losses. See Note 10 of the Notes to Consolidated Condensed Financial Statements for further information.

Results of Operations for the Nine Months Ended September 30, 2009 and 2008

Below are the results of operations for the nine months ended September 30, 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 period 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	$ 4,882	$ 7,920	$ (3,038)	(38) %
Mark-to-market activity[1]	97	14	83	#
Other revenue	16	35	(19)	(54)
Operating revenues	4,995	7,969	(2,974)	(37)
Cost of revenue:				
Fuel and purchased energy expense:				
Commodity expense	2,930	5,932	3,002	51
Mark-to-market activity[1]	37	3	(34)	#
Fuel and purchased energy expense	2,967	5,935	2,968	50
Plant operating expense	654	636	(18)	(3)
Depreciation and amortization expense	330	329	(1)	—
Other cost of revenue[2]	63	88	25	28
Total cost of revenue	4,014	6,988	2,974	43
Gross profit	981	981	—	—
Sales, general and other administrative expense	131	154	23	15
(Income) loss from unconsolidated investments in power plants	(27)	189	216	#
Other operating expense	14	15	1	7
Income from operations	863	623	240	39
Interest expense	615	837	222	27
Interest (income)	(13)	(38)	(25)	(66)
Debt extinguishment costs	49	13	(36)	#
Other (income) expense, net	8	16	8	50
Income (loss) before reorganization items and income taxes	204	(205)	409	#
Reorganization items	(2)	(263)	(261)	(99)
Income before income taxes	206	58	148	#
Income tax expense (benefit)	17	(60)	(77)	#
Net income	189	118	71	60
Net loss attributable to the noncontrolling interest	3	1	2	#
Net income attributable to Calpine	$ 192	$ 119	$ 73	61

Operating Performance Metrics:	2009	2008	Change	% Change
MWh generated (in thousands)[3]	66,717	67,890	(1,173)	(2) %
Average availability	92.9%	90.8%	2.1	2
Average total MW in operation	23,423	23,097	326	1
Average capacity factor, excluding peakers	49.0%	49.0%	—	—
Steam Adjusted Heat Rate	7,246	7,237	(9)	—

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\# Variance of 100% or greater

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

(2) Includes $5 million and nil of RGGI compliance costs for the nine months ended September 30, 2009 and 2008, respectively, which is a component of Commodity Margin.

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

Commodity revenue, net of commodity expense, decreased $36 million for the nine months ended September 30, 2009 compared to the same period in 2008, primarily due to the following regional factors:

- *West* — Commodity Margin increased 3% as a result of higher hedge levels, higher average hedge prices, sales of surplus emission allowances in the first quarter of 2009 and an unfavorable natural gas storage inventory price adjustment in September 2008 with no similar adjustments in 2009.
- *Texas* — Commodity Margin decreased 14% due to weaker natural gas prices and Market Heat Rates as well as the comparative impact of congestion-driven pricing observed in the second quarter of 2008 that was much greater than the comparable period in 2009.
- *Southeast* — Commodity Margin increased 12% due to higher average hedge prices, higher hedge levels and higher Market Heat Rates related to our open positions. These factors were partially offset by the negative impact from an unfavorable arbitration ruling on a stream contract during the second quarter of 2009 and a gain of $21 million related to the temporary assignment of a transmission capacity contract in the second quarter of 2008.
- *North* — Commodity Margin decreased 6% due to lower average hedge prices in 2009 compared to 2008.

Net unrealized mark-to-market activity primarily resulting from our portfolio hedging activities that do not qualify for hedge accounting increased $49 million for the nine months ended September 30, 2009, compared to the same period in 2008. The increase in revenues from mark-to-market activity was primarily driven by the impact of current year falling power prices and the resulting gain on our short hedge positions in operating revenues. Similarly, the increase in expenses from mark-to-market activity was primarily driven by the impact of the increase in natural gas prices since our hedges used to economically hedge a portion of our 2010 and 2011 spark spread were executed.

Other revenue decreased for the nine months ended September 30, 2009 compared to the same period in 2008, primarily related to a $10 million decrease in revenue from operation and maintenance contracts and a $7 million decrease in revenue from construction management projects completed in 2008.

Normal, recurring costs in plant operating expense decreased for the nine months ended September 30, 2009 compared to the same period in 2008, after accounting for $30 million in reimbursements for insurance claims from prior periods that reduced expenses in the nine months ended September 30, 2008 partially offset by a $6 million increase in 2009 major maintenance costs resulting from our plant outage schedule.

Other cost of revenue decreased for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008, as a result of a decrease of $17 million related to the discontinuation of the amortization of other assets associated with the deconsolidation and subsequent sale of Auburndale in 2008 as well as a $10 million decrease in royalty expense due to lower revenues from our Geysers Assets resulting from lower spot market power prices in the nine months ended September 30, 2009 compared to the same period in 2008. The decrease was partially offset by an increase of $5 million in expenses related to RGGI compliance in the Northeast which was initiated in 2009.

Sales, general and other administrative expense decreased for the nine months ended September 30, 2009 compared to the same period in 2008, due to a $9 million decrease in personnel costs and stock-based compensation expense resulting primarily from a lower headcount in 2009 as well as a $12 million decrease in legal and consulting expenses.

Our (income) loss from unconsolidated investments in power plants increased for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008, primarily due to an impairment loss of $179 million related to our equity interest in Auburndale recorded during the third quarter of 2008. Also contributing to the increase was income from our investment in Greenfield LP of $11 million for the nine months ended September 30, 2009, which is due to Greenfield LP achieving commercial operations in October 2008, compared to a loss of $17 million from interest rate hedging for the nine months ended September 30, 2008.

Due to the changes in our capital structure on the Effective Date, our interest expense for the nine months ended September 30, 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 and $27 million for settlement obligations related to the Canadian Debtors and other deconsolidated foreign entities recorded prior to their reconsolidation in February 2008. In addition, interest expense decreased for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008, due to lower average interest rates on our variable rate debt resulting from a decrease in LIBOR over the same periods. The annualized effective interest rates on our consolidated debt, excluding the impacts of capitalized interest and unrealized mark-to-market gains (losses) on interest rate swaps, after amortization of deferred financing costs and debt discounts, were 7.9% and 8.9% for the nine months ended September 30, 2009 and 2008, respectively. The decrease in interest expense was partially offset by the negative period over period impact of $90 million related to our interest rate swaps on our First Lien Credit Facility resulting from a decrease in LIBOR.

Interest income decreased for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008, largely resulting from lower average interest rates earned on our cash balances which were primarily invested in U.S. Treasury securities or government-backed securities for the nine months ended September 30, 2009 compared to primarily invested in institutional-backed money market accounts for the nine months ended September 30, 2008.

Debt extinguishment costs increased for the nine months ended September 30, 2009 compared to the same period in 2008, primarily due to $49 million in debt extinguishment costs associated with the refinancing of our CCFC Old Notes and CCFC Term Loans in May and June 2009 and the CCFCP Preferred Shares that were redeemed on or before July 1, 2009. This increase was partially offset by $13 million in debt extinguishment costs for the write-off of unamortized deferred financing costs and other costs associated with the refinancing of all outstanding indebtedness under the existing Blue Spruce term loan facility in February 2008 as well as the refinancing of our Metcalf term loan facility and preferred interests in June 2008.

Other (income) expense, net had a favorable variance primarily as a result of a $13 million loss incurred during the nine months ended September 30, 2008 related to our settlement with Panda partially offset by a $3 million unfavorable change in foreign exchange gains and losses in the same period in 2009.

During the nine months ended September 30, 2009, reorganization items primarily consisted of a credit of approximately $6 million related to a favorable settlement during the third quarter of 2009 from a disputed claim on a PPA contract that was terminated in January 2006, partially offset by charges related to other disputed claims settled in 2009. During the nine months ended September 30, 2008, reorganization items primarily consisted of $204 million in gains on asset sales, a $69 million gain on the reconsolidation of the Canadian Debtors and other deconsolidated foreign entities, a $62 million credit related to the settlement of claims with the Canadian Debtors and other deconsolidated foreign entities and $80 million in professional and trustee fees related to activity managed by our third party advisors for our Chapter 11 and CCAA cases.

For the nine months ended September 30, 2009, we recorded income tax expense of $17 million compared to a benefit of $60 million for the nine months ended September 30, 2008. Our 2009 income tax expense was due to the effect of $42 million of reversing intraperiod tax allocations and $1 million of other tax expense partially offset by a $26 million benefit from the CCFC group. In 2008, we recorded a $101 benefit resulting from 2008 OCI losses. See Note 10 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 September 30, 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, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, RGGI compliance costs, and cash settlements from our marketing, hedging and optimization activities that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other 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 15 of the Notes to Consolidated Condensed Financial Statements for a reconciliation of Commodity Margin to income (loss) from operations by segment.

The following tables show our Commodity Margin and related operating performance metrics by segment for the three months ended September 30, 2009 and 2008. During the first quarter of 2009, we began assessing the performance of our regional segments to include the allocation (based upon each regional segment's MWh) of revenues and expenses from our fuel management, TMG, certain non-region specific natural gas marketing and optimization and other corporate activities, which had formerly been separately reported as our "Other" segment. 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 period presentation. In the "Change" and "% Change" columns below, favorable variances are shown without brackets while unfavorable variances are shown with brackets.

	Three Months Ended September 30,			
West:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 393	$ 372	$ 21	6 %
Commodity Margin per MWh generated	$ 37.62	$ 35.22	$ 2.40	7
MWh generated (in thousands)	10,447	10,563	(116)	(1)
Average availability	95.2%	95.8%	(0.6)	(1)
Average total MW in operation	7,246	7,246	—	—
Average capacity factor, excluding peakers	73.0%	73.9%	(0.9)	(1)
Steam Adjusted Heat Rate	7,302	7,314	12	—

West — Commodity Margin in our West segment increased by $21 million, or 6%, for the three months ended September 30, 2009 compared to the same period in 2008. Despite on-peak spark spreads in California settling substantially lower for the three months ended September 30, 2009 compared to the same period in 2008, Commodity Margin increased primarily as a result of higher hedge prices and, although spark spreads were lower overall, the higher Market Heat Rate component of spark spread where we had hedged the corresponding open natural gas position. The higher Market Heat Rates were primarily in the Pacific Northwest region, which experienced high market generation outages and warmer weather. In addition, the current period benefited from the non-recurrence in 2009 of an unfavorable natural gas storage inventory pricing adjustment in September 2008. Generation decreased 1% for the three months ended September 30, 2009 compared to the same period in 2008, due in part to a 1% decrease in average availability.

	Three Months Ended September 30,			
Texas:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 187	$ 233	$ (46)	(20) %
Commodity Margin per MWh generated	$ 18.25	$ 23.70	$ (5.45)	(23)
MWh generated (in thousands)	10,246	9,830	416	4
Average availability	97.5%	96.9%	0.6	1
Average total MW in operation	7,251	7,251	—	—
Average capacity factor, excluding peakers	64.0%	61.4%	2.6	4
Steam Adjusted Heat Rate	7,227	7,147	(80)	(1)

Texas — Commodity Margin in our Texas segment decreased by $46 million, or 20%, for the three months ended September 30, 2009 compared to the same period in 2008, primarily resulting from weaker spark spreads caused by lower natural gas prices, which declined 64% in the third quarter of 2009 compared to 2008. The decrease in Commodity Margin was also attributable to reduced steam sales and a relative period on period decline in the optimization margin that benefited us during Hurricane Ike in September 2008 when it was more advantageous to buy as opposed to generate power to cover our hedges given the extremely low power prices. The adverse impact of the lower spark spreads in 2009 was partially offset by an increase in Market Heat Rates and higher average availability. Generated volumes increased 4% resulting from the impact of increased off-peak generation in response to higher off-peak spark spreads combined with a relative increase in September 2009 generation due to the market disruption of Hurricane Ike in September 2008. The increase in generated volumes was partially offset by a decrease in on-peak generation as a result of weaker on-peak spark spreads.

Southeast:	Three Months Ended September 30, 2009	2008	Change	% Change
Commodity Margin (in millions)	$ 92	$ 95	$ (3)	(3) %
Commodity Margin per MWh generated	$ 15.32	$ 25.31	$ (9.99)	(39)
MWh generated (in thousands)	6,006	3,753	2,253	60
Average availability	98.2%	97.4%	0.8	1
Average total MW in operation	6,104	6,205	(101)	(2)
Average capacity factor, excluding peakers	51.0%	29.8%	21.2	71
Steam Adjusted Heat Rate	7,187	7,335	148	2

Southeast — Commodity Margin in our Southeast segment decreased by $3 million, or 3%, resulting from lower on-peak spark spreads related to open positions in the third quarter of 2009 compared to the same period in 2008, which was largely offset by the positive impact of higher hedge volumes and hedge prices, as well as a new tolling contract, for the three months ended September 30, 2009 compared to 2008. Generated volumes increased 60% for the three months ended September 30, 2009 compared to the same period in 2008, primarily due to significantly higher off-peak dispatch in response to higher off-peak spark spreads; however, the extra generation in the third quarter of 2009 provided relatively less incremental Commodity Margin than in prior quarters due to the lower off-peak margin and the fact that many of our power plants in the Southeast have tolling contracts. The strength in off-peak spark spreads was attributed to higher natural gas generation displacement of coal generation in certain sub-markets in our Southeast segment, as well as the favorable impact of an off-take agreement at one of our power plants. The 101 MW, or 2%, decrease in our average total MW in operation for the three months ended September 30, 2009 compared to 2008, was due to the deconsolidation of Auburndale in the third quarter of 2008.

North:	Three Months Ended September 30, 2009	2008	Change	% Change
Commodity Margin (in millions)	$ 96	$ 100	$ (4)	(4) %
Commodity Margin per MWh generated	$ 71.01	$ 61.46	$ 9.55	16
MWh generated (in thousands)	1,352	1,627	(275)	(17)
Average availability	98.5%	96.7%	1.8	2
Average total MW in operation	2,822	2,362	460	19
Average capacity factor, excluding peakers	31.5%	39.1%	(7.6)	(19)
Steam Adjusted Heat Rate	7,758	7,722	(36)	—

North — Commodity Margin in our North segment decreased by $4 million, or 4%, primarily due to lower average hedge prices during the three months ended September 30, 2009 compared to the same period in 2008. Despite a 2% increase in our average availability and an increase of 460 MW in operation, generation declined by 17% in the third quarter of 2009 compared to the same period in 2008. The 460 MW, or 19%, increase in our average total MW in operation for the three months ended September 30, 2009 compared to the same period in 2008, was due to the reconsolidation of RockGen in December 2008. Commodity Margin per MWh generated increased 16% due in part to the effect of our portfolio hedge value being allocated across a reduced number of generated MWh in the three months ended September 30, 2009 as compared to the same period in 2008.

Commodity Margin by Segment for the Nine Months Ended September 30, 2009 and 2008

The following tables show our Commodity Margin and related operating performance metrics by segment for the nine months ended September 30, 2009 and 2008. Our 2008 Commodity Margin by segment information has been recast to conform to the current period presentation. In the "Change" and "% Change" columns below, favorable variances are shown without brackets while unfavorable variances are shown with brackets.

West:	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	Change	% Change
Commodity Margin (in millions)	$ 994	$ 965	$ 29	3 %
Commodity Margin per MWh generated	$ 38.07	$ 34.84	$ 3.23	9
MWh generated (in thousands)	26,108	27,702	(1,594)	(6)
Average availability	92.3%	89.6%	2.7	3
Average total MW in operation	7,246	7,246	—	—
Average capacity factor, excluding peakers	62.3%	65.9%	(3.6)	(5)
Steam Adjusted Heat Rate	7,299	7,287	(12)	—

West — Commodity Margin in our West segment increased by $29 million, or 3%, for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008. Spark spreads for the nine months ended September 30, 2009 settled substantially lower compared to the same period in 2008, primarily as a result of lower natural gas prices combined with weak power demand and conservative ISO operations during the launch of MRTU in 2009. Despite this, Commodity Margin in the West improved primarily as a result of higher hedge levels, higher average hedge prices and sales of surplus emission allowances in the first quarter of 2009. In addition, the current period benefited from the non-recurrence in 2009 of an unfavorable natural gas storage inventory price adjustment in September 2008. Consistent with the weaker price conditions, generation decreased 6% for the nine months ended September 30, 2009 compared to the same period in 2008, despite a 3% increase in our average availability. Commodity Margin per MWh generated increased 9% due in part to the effect of our positive portfolio hedge value being allocated across a reduced number of generated MWh in the nine months ended September 30, 2009 as compared to the same period in 2008.

Texas:	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	Change	% Change
Commodity Margin (in millions)	$ 505	$ 587	$ (82)	(14) %
Commodity Margin per MWh generated	$ 21.90	$ 21.70	$ 0.20	1
MWh generated (in thousands)	23,058	27,048	(3,990)	(15)
Average availability	92.1%	90.1%	2.0	2
Average total MW in operation	7,251	7,251	—	—
Average capacity factor, excluding peakers	48.5%	56.7%	(8.2)	(14)
Steam Adjusted Heat Rate	7,149	7,090	(59)	(1)

Texas — Commodity Margin in our Texas segment decreased by $82 million, or 14%, for the nine months ended September 30, 2009 compared to the same period in 2008. This decrease is primarily attributable to weaker natural gas prices that were 62% lower in 2009 compared to the nine months ended September 30, 2008, a decline in Market Heat Rates that were 23% lower than the congestion-driven pricing environment of the second quarter of 2008 and lower steam sales resulting from weaker industrial demand. Despite a 2% increase in average availability, generation decreased 15% on softer demand in the first half of 2009 and weaker Market Heat Rates in the second quarter of 2009. Commodity Margin per MWh generated increased 1% due in part to the effect of our portfolio hedge value being allocated across a reduced number of generated MWh in the nine months ended September 30, 2009 as compared to the same period in 2008.

Southeast:	Nine Months Ended September 30, 2009	2008	Change	% Change
Commodity Margin (in millions)	$ 233	$ 208	$ 25	12 %
Commodity Margin per MWh generated	$ 16.83	$ 22.96	$ (6.13)	(27)
MWh generated (in thousands)	13,842	9,058	4,784	53
Average availability	93.3%	92.6%	0.7	1
Average total MW in operation	6,104	6,238	(134)	(2)
Average capacity factor, excluding peakers	40.0%	24.5%	15.5	63
Steam Adjusted Heat Rate	7,214	7,409	195	3

Southeast — Commodity Margin in our Southeast segment increased by $25 million, or 12%, driven primarily by higher average hedge prices, higher hedge levels and higher Market Heat Rates related to our open positions in the nine months ended September 30, 2009 compared to the same period in 2008. Generated volumes increased by 53% for the nine months ended September 30, 2009 compared to the same period in 2008, primarily resulting from significantly higher off-peak dispatch in response to higher off-peak spark spreads in the 2009 period. The strength in off-peak spark spreads was attributed to higher natural gas generation displacement of coal generation in certain sub-markets in our Southeast segment, as well as the favorable impact of an off-take agreement at one of our power plants. The benefit from these positive performance factors was partially offset by an unfavorable arbitration ruling on a steam contract, which adversely impacted operating revenues during the second quarter of 2009. In addition, a gain of $21 million related to the temporary assignment of a transmission capacity contract in the second quarter of 2008 led a reduction in relative year over year performance. The 134 MW, or 2%, decrease in our average total MW in operation for the nine months ended September 30, 2009 compared to 2008, was due to the deconsolidation of Auburndale in the third quarter of 2008.

North:	Nine Months Ended September 30, 2009	2008	Change	% Change
Commodity Margin (in millions)	$ 215	$ 228	$ (13)	(6) %
Commodity Margin per MWh generated	$ 57.97	$ 55.85	$ 2.12	4
MWh generated (in thousands)	3,709	4,082	(373)	(9)
Average availability	95.5%	92.0%	3.5	4
Average total MW in operation	2,822	2,362	460	19
Average capacity factor, excluding peakers	30.1%	33.8%	(3.7)	(11)
Steam Adjusted Heat Rate	7,693	7,596	(97)	(1)

North — Commodity Margin in our North segment decreased by $13 million, or 6%, primarily due to lower average hedge prices during the nine months ended September 30, 2009 compared to 2008. Despite a 4% increase in our average availability and an increase of 460 MW in operation, generation declined by 9% in the nine months ended September 30, 2009 compared to the same period in 2008. The 460 MW, or 19%, increase in our average total MW in operation for the nine months ended September 30, 2009 compared to the same period in 2008, was due to the reconsolidation of RockGen in December 2008. Commodity Margin per MWh generated increased 4% due in part to the effect of our portfolio hedge value being allocated across a reduced number of generated MWh in the nine months ended September 30, 2009 as compared to the same period in 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 First Lien 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 includes non-cash gains and losses 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 gains and losses on dispositions of assets are useful in evaluating our overall performance and therefore we adjust for 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 represents EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortization) adjusted for the income effects of non-cash gains or losses on sales, dispositions or impairments of assets, any unrealized gains or losses and any non-cash realized gains or losses from accounting for derivatives, stock-based compensation expense, operating lease expense, non-cash gains and losses from intercompany foreign currency translations, reorganization items, major maintenance expense, gains or losses on the repurchase or extinguishment of debt and any other extraordinary, unusual or non-recurring items plus adjustments to reflect the Adjusted EBITDA from our unconsolidated investments. We exclude these items 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 as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends, as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations, and in communications with our Board of Directors, shareholders, creditors, analysts and investors concerning our financial performance.

The tables below provide a reconciliation of Adjusted EBITDA to our income (loss) from operations on a segment basis and to net income attributable to Calpine on a consolidated basis for the three and nine months ended September 30, 2009 and 2008 (in millions).

	Three Months Ended September 30, 2009					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 238
Net loss attributable to noncontrolling interest						(1)
Income tax benefit						(7)
Reorganization items						(8)
Other (income) expense and debt extinguishment costs, net						20
Interest expense, net						195
Income from operations	$ 237	$ 107	$ 33	$ 70	$ (10)	$ 437
Add:						
Adjustments to reconcile income from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs[1]	50	29	17	16	(2)	110
Major maintenance expense	11	4	5	2	—	22
Operating lease expense	6	—	—	6	—	12
Unrealized (gains) losses on commodity derivative mark-to-market activity	(34)	3	7	(19)	—	(43)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments[2][3]	13	—	—	15	—	28
Stock-based compensation expense	3	3	2	—	—	8
Non-cash loss on dispositions of assets	4	6	2	—	—	12
Other	1	—	—	(1)	—	—
Adjusted EBITDA	$ 291	$ 152	$ 66	$ 89	$ (12)	$ 586

	Three Months Ended September 30, 2008[4]					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 136
Net loss attributable to noncontrolling interest						(1)
Income tax benefit						(80)
Reorganization items						(2)
Other (income) expense and debt extinguishment costs, net						18
Interest expense, net						201
Income (loss) from operations	$ 136	$ 306	$ (143)	$ (35)	$ 8	$ 272
Add:						
Adjustments to reconcile income (loss) from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs[1]	49	33	21	16	(2)	117
Impairment loss[2]	—	—	179	—	—	179
Major maintenance expense	10	4	5	3	—	22
Operating lease expense	5	—	—	7	—	12
Non-cash realized gains on derivatives	—	(13)	—	—	—	(13)
Unrealized (gains) losses on commodity derivative mark-to-market activity	56	(170)	(1)	72	—	(43)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments[2][3]	9	—	2	23	—	34
Stock-based compensation expense	8	6	2	1	—	17
Non-cash loss (gain) on dispositions of assets	(2)	—	3	—	—	1
Other	—	(2)	(1)	(1)	—	(4)
Adjusted EBITDA	$ 271	$ 164	$ 67	$ 86	$ 6	$ 594

	Nine Months Ended September 30, 2009					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 192
Net loss attributable to noncontrolling interest						(3)
Income tax expense						17
Reorganization items						(2)
Other (income) expense and debt extinguishment costs, net						57
Interest expense, net						602
Income from operations	$ 549	$ 144	$ 61	$ 121	$ (12)	$ 863
Add:						
Adjustments to reconcile income from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	152	92	53	47	(5)	339
Major maintenance expense	69	33	21	1	—	124
Operating lease expense	16	—	—	19	—	35
Unrealized (gains) losses on commodity derivative mark-to-market activity	(95)	63	5	(33)	—	(60)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(2)(3)	(13)	—	—	24	—	11
Stock-based compensation expense	13	10	5	2	—	30
Non-cash loss on dispositions of assets	10	13	4	2	—	29
Other	3	—	—	—	—	3
Adjusted EBITDA	$ 704	$ 355	$ 149	$ 183	$ (17)	$ 1,374

	Nine Months Ended September 30, 2008(4)					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 119
Net loss attributable to noncontrolling interest						(1)
Income tax benefit						(60)
Reorganization items						(263)
Other (income) expense and debt extinguishment costs, net						29
Interest expense, net						799
Income (loss) from operations	$ 368	$ 355	$ (149)	$ 40	$ 9	$ 623
Add:						
Adjustments to reconcile income (loss) from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	146	99	75	41	(4)	357
Impairment loss	6	—	179(2)	—	—	185
Major maintenance expense	55	36	18	9	—	118
Operating lease expense	16	—	—	19	—	35
Non-cash realized gains on derivatives	—	(33)	—	—	—	(33)
Unrealized (gains) losses on commodity derivative mark-to-market activity	62	(68)	(1)	29	—	22
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(2)(3)	(6)	—	2	33	—	29
Stock-based compensation expense	17	12	5	2	—	36
Non-cash loss (gain) on dispositions of assets	5	1	4	—	(1)	9
Other	(6)	3	(1)	(3)	—	(7)
Adjusted EBITDA	$ 663	$ 405	$ 132	$ 170	$ 4	$ 1,374

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

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

(3) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include $14 million and $12 million in unrealized (gains) losses on mark-to-market activity for the three months ended September 30, 2009 and 2008, respectively, and $(14) million and $4 million for the nine months ended September 30, 2009 and 2008, respectively.

(4) Adjusted EBITDA for the three and nine months ended September 30, 2008, has been recast to conform to our current period definition.

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.

Liquidity — As of September 30, 2009, we had $913 million in cash and cash equivalents and $505 million of restricted cash. On September 28, 2009 we repaid $725 million previously drawn under our First Lien Credit Facility revolver on October 2, 2008 from cash on hand. Our availability under our First Lien Credit Facility revolver as of September 30, 2009, is $789 million for future letters of credit or cash borrowings. The following table provides a summary of our liquidity position at September 30, 2009, and December 31, 2008 (in millions):

	September 30, 2009	December 31, 2008
Cash and cash equivalents, corporate(1)	$ 681	$ 1,361
Cash and cash equivalents, non-corporate	232	296
Total cash and cash equivalents	913	1,657
Restricted cash	505	503
Letter of credit availability(2)	2	2
Revolver availability	789	16
Total current availability(3)	$ 2,209	$ 2,178

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(1) Includes $1 million and $169 million of margin deposits held by us posted by our counterparties as of September 30, 2009, and December 31, 2008, respectively.
(2) Includes available balances for Calpine Development Holdings, Inc.
(3) Excludes contingent amounts of $150 million under the Knock-in Facility and $200 million under the Commodity Collateral Revolver as of December 31, 2008.

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 are unable to predict the length or severity of the economic downturn; but 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.

Additionally, 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 economically hedged a substantial portion of our Commodity Margin for the remainder of 2009. Additionally, we have economically hedged much of 2010 and therefore do not expect further declines in natural gas prices to result in a material detriment to 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:

- improving the profitability of our operations;
- continued compliance with the covenants under our First Lien Credit Facility, First Lien Notes and other existing financing obligations;
- stabilizing and increasing future contractual cash flows; and
- our significant counterparties performing under their contracts with us.

Liquidity Sensitivity — Significant changes in commodity prices and Market Heat Rates can have an impact on our liquidity as we use margin deposits, cash prepayments and letters of credit as credit support (collateral) with and from our counterparties for commodity procurement and risk management activities. Utilizing our portfolio of transactions subject to collateral exposure, we estimate that as of October 16, 2009, an increase of $1/MMBtu in natural gas prices would result in an increase of collateral required of approximately $150 million. If natural gas prices decreased by $1/MMBtu, we estimate that our collateral requirements would decrease by approximately $146 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 October 16, 2009, an increase of 170 Btu/KWh in the Market Heat Rate would result in an increase in collateral required of approximately $35 million. If Market Heat Rates were to fall at a similar rate, we estimate that our collateral required would decrease by $33 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 First Lien Credit Facility to collateralize our obligations under certain of our power and natural gas agreements that qualify as "eligible commodity hedge agreements" under the First Lien 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 First Lien Credit Facility and First Lien Notes. During 2009, we have increased our usage of these additional liens in order to help manage cash collateral that would otherwise be required. See Note 9 of the Notes to Consolidated 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 the Commodity Collateral Revolver to increase our liquidity available to collateralize obligations to counterparties under eligible commodity hedge agreements during periods of increasing energy commodity prices. The Commodity Collateral Revolver provided up to a total maximum availability of $300 million contingent on mark-to-market exposure amounts under certain reference transactions. We received an initial advance of $100 million in 2008; however, on August 13, 2009, we terminated $200 million of the remaining availability under the Commodity Collateral Revolver in accordance with its terms as energy commodity prices were not expected to exceed stated thresholds in the near future and it was considered unlikely that any of the remaining $200 million availability would be available to us. The $100 million outstanding under the Commodity Collateral Revolver will mature on July 8, 2010.

We believe that we have adequate resources from a combination of cash and cash equivalents on hand and cash expected to be generated from future operations to continue to meet our obligations as they become due. Despite the current volatility in the financial markets and relative illiquidity, we were opportunistically able to amend our credit agreement to our First Lien Credit Facility and close significant financings during 2009 as further described below. If investor and creditor markets improve and more confidence returns, we may continue to refinance additional portions of our nearer term maturities or more costly debt.

Amendment of First Lien Credit Facility and Issuance of First Lien Notes due 2017 — We executed the First Amendment to Credit Agreement and Second Amendment to Collateral Agency and Intercreditor Agreement dated as of August 20, 2009, which amended both the First Lien Credit Facility Credit Agreement and the First Lien Credit Facility Collateral Agency and Intercreditor Agreement. The amendment provides additional flexibility with our capital structure and First Lien Credit Facility by granting us the option, subject to certain conditions, to buy back debt at a discount using cash on hand via an auction process; to offer first lien bonds in exchange for or to retire First Lien Credit Facility term loans; to issue up to $2.0 billion of first lien bonds in lieu of issuing first lien term loans under the accordion provision of the First Lien Credit Facility; and to extend all or a portion of the revolver and term loan maturities, on revised terms, subject to acceptance by applicable lenders. In addition, the amendment provides for the aggregation of various investment and capital expenditure baskets for covenant purposes.

We subsequently issued approximately $1.2 billion aggregate principal amount of First Lien Notes in a private placement on October 21, 2009. We received no net cash proceeds from the transaction. The offer and sale of the First Lien Notes was consummated as a permitted debt exchange pursuant to the First Lien Credit Facility in exchange for a like principal amount of First Lien Credit Facility term loans. Upon their exchange for First Lien Notes, such term loans were canceled and may not be redrawn. The First Lien Notes bear interest at 7.25% per annum payable on April 15 and October 15 of each year, beginning on April 15, 2010. The First Lien Notes will mature on October 15, 2017; however, among other things, prior to October 15, 2012, we may redeem up to 35% of the aggregate principal amount of the First Lien Notes with the net cash proceeds of certain equity offerings, at a price equal to 107.25% of the aggregate principal amount thereof, plus accrued and unpaid interest. Beginning on October 15, 2013, we may redeem all or a portion of the First Lien Notes at a premium as defined in the indenture governing the First Lien Notes. The First Lien Notes are guaranteed by each of our current and future domestic subsidiaries that is a borrower or guarantor under our First Lien Credit Facility and the First Lien Notes rank equally in right of payment with all of our and the guarantors' other existing and future senior indebtedness, and will be effectively subordinated in right of payment to all existing and future liabilities of our subsidiaries that do not guarantee the First Lien Notes. The First Lien Notes are secured equally and ratably with indebtedness under our First Lien Credit Facility by a first-priority lien, subject to certain exceptions and permitted liens, on substantially all of our and certain of the guarantors' existing and future assets.

Subject to certain qualifications and exceptions, the First Lien Notes will, among other things, limit our ability and the ability of the guarantors to:

- incur or guarantee additional first lien indebtedness;
- enter into commodity hedge agreements;
- enter into sale and leaseback transactions;
- create or incur liens; and
- consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries on a combined basis.

CCFC Refinancing — On May 19, 2009, our wholly owned subsidiaries, CCFC and CCFC Finance, issued $1.0 billion in aggregate principal amount of CCFC New Notes in a private placement. Interest on the CCFC New Notes accrues at the rate of 8.0% per annum and is payable semi-annually in arrears on each June 1 and December 1, commencing on December 1, 2009. The CCFC New Notes, which mature on June 1, 2016, are guaranteed by two of CCFC's subsidiaries. The CCFC New Notes and the related guarantees are secured, subject to certain exceptions and permitted liens, by all real and personal property of CCFC and CCFC's material subsidiaries (including the CCFC Guarantors), consisting primarily of six natural gas power plants as well as the equity interests in CCFC and the CCFC Guarantors. The CCFC New Notes are not guaranteed by Calpine Corporation and are without recourse to Calpine Corporation or any of our other non-CCFC or CCFC Finance subsidiaries or assets. The net proceeds received of $939 million, together with CCFC cash on hand of $271 million, were used to:

- repay the $364 million outstanding under the CCFC Term Loans on May 19, 2009;
- redeem the $415 million outstanding principal amount of CCFC Old Notes on June 18, 2009;
- distribute $327 million to CCFC's indirect parent, CCFCP, which was used by CCFCP to redeem its $300 million CCFCP Preferred Shares on or before July 1, 2009; and
- in each case, pay any interest, prepayment penalties and other amounts due through the date of such repayment or redemption.

In connection with the CCFC Refinancing, we recorded $16 million and $49 million in debt extinguishment costs for the three and nine months ended September 30, 2009, respectively. Debt extinguishment costs recorded for the three months ended September 30, 2009 related to prepayment penalties and the write-off of unamortized deferred financing costs for the CCFCP Preferred Shares that were redeemed on July 1, 2009. Debt extinguishment costs for the nine months ended September 30, 2009 are comprised of $7 million from the write-off of unamortized deferred financing costs and unamortized debt discount and $24 million of prepayment penalties related to redemption of the CCFC Old Notes, and $2 million from the write-off of unamortized deferred financing costs and unamortized debt discount and $16 million related to prepayment penalties related to the redemption of the CCFCP Preferred Shares.

We also recorded approximately $21 million in new deferred financing costs on our Consolidated Condensed Balance Sheet upon closing the CCFC Refinancing.

As a result of the CCFC Refinancing transactions, we were able to extend the maturities of approximately $1.0 billion of debt by several years, at the same time converting it from a floating to a fixed interest rate and lowering our interest rate on such debt to 8.0% from a current weighted average interest rate of approximately 9.4% with respect to the CCFC Term Loans, CCFC Old Notes and CCFCP Preferred Shares.

Concurrent with the CCFC Refinancing, we replaced various intercompany agreements with our CCFC subsidiaries for the related sales and purchases of power, natural gas and the operation and maintenance of our CCFC power plants, which did not materially impact our results of operations, financial condition or cash flows on a consolidated basis.

Deer Park Financing — On January 21, 2009, Deer Park, our indirect wholly owned subsidiary, closed on $156 million of senior secured credit facilities, which include a $150 million term facility and a $6 million letter of credit facility. Proceeds received were used to settle an existing commodity contract of approximately $79 million, pay financing and legal fees of approximately $8 million and fund approximately $22 million in restricted cash. The remainder was distributed to Calpine Corporation for general corporate purposes. The senior term loan facility matures on January 21, 2012, and bears interest of LIBOR plus 3.5% or base rate plus 2.5% at Deer Park's option.

Letter of Credit Facilities — The table below represents amounts outstanding under our letter of credit facilities as of September 30, 2009 (in millions):

		2009
First Lien Credit Facility	$	211
Calpine Development Holdings, Inc.		148
Various project financing facilities		104
Total	$	463

Cash Management — We manage our cash in accordance with our intercompany cash management system subject to the requirements of the First Lien 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 most of our money market accounts invest in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. government, its agencies or instrumentalities.

We do not expect to pay any cash dividends on our common stock for the foreseeable future because we are currently prohibited under the First Lien Credit Facility and certain of our other debt agreements from paying cash dividends. 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 applicable carryover periods. Our federal and state income tax reporting group is comprised primarily of two groups, CCFC and its subsidiaries, which we refer to as the CCFC group and Calpine Corporation and its subsidiaries other than CCFC, which we refer to as the Calpine group. As of December 31, 2008, our consolidated federal NOLs totaled approximately $7.5 billion, which consists of approximately $7.1 billion from the Calpine group and approximately $396 million from the CCFC group. During 2009, the Calpine group reduced its NOLs approximately $324 million and the CCFC group increased its NOLs approximately $5 million. The changes in each group's NOLs resulted from the cancellation of debt income resulting from the Calpine group's emergence from Chapter 11 and adjustments to each group's federal taxable income for 2008 and prior years as a result of the finalization and filing of their respective 2008 federal income tax returns. Accordingly, our adjusted consolidated federal NOLs at December 31, 2008 totaled approximately $7.2 billion, which consisted of approximately $6.8 billion from the Calpine group and approximately $401 million from the CCFC group. The 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. Approximately $5.5 billion of our NOLs have annual limitations under Section 382 of the IRC. Subject to limitations, Section 382 amounts not used can be carried forward to succeeding years. We expect to generate approximately $90 million to $100 million in federal NOLs in 2009 from our consolidated groups. In addition, as of September 30, 2009 we have approximately $1.0 billion in foreign NOLs and $4.6 billion in state NOLs on a consolidated basis.

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.

OMEC began commercial operations on October 3, 2009. The completion of OMEC added approximately 608 MW of baseload (with peaking) capacity representing our unconsolidated net interest in the power plant.

Russell City Energy Center, remains in advanced development. 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. 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, through certain of our wholly owned subsidiaries, amended certain PPAs and entered into new PPAs with PG&E, and entered into a PPA with Southern California Edison related to certain of our power plants in California. The amended and new PPAs are all on mutually beneficial terms and many are subject to regulatory approvals and, among other things, provide for the following:

- We and PG&E have agreed to an extension of the term and an increase in the volume under the existing contracts for delivery of power from our Geysers Assets. The Geysers Assets currently provide PG&E 375 MW of power under two contracts. We have agreed to increase the volume to 425 MW through 2017, and, from 2018 through the end of 2021, our Geysers Assets will supply PG&E 250 MW of renewable energy.
- Our wholly owned subsidiaries, Gilroy Energy Center, LLC, Creed Energy Center, LLC, and Goose Haven Energy Center, LLC, have entered into a replacement contract with PG&E, whereby PG&E will have greater dispatch flexibility for all 11 of our peaker power plants in California through 2017 and for seven of our peaker power plants through 2021.
- We and PG&E negotiated a new agreement to replace the existing California Department of Water Resources contract and facilitate the upgrade of our Los Esteros power plant from a 180 MW simple-cycle generation power plant to a 300 MW combined-cycle generation power plant. In addition to the increase in capacity, the upgrade will increase the efficiency and environmental performance of the power plant by lowering the Heat Rate. While the upgrade is under construction, we will provide capacity from our Gilroy Cogeneration power plant. Upon completion of the upgrade, PG&E will purchase all of the capacity from our Los Esteros power plant for a term of ten years.
- We have entered into a new tolling arrangement with PG&E for all of the capacity from our Delta power plant beginning January 1, 2011 and ending December 31, 2013.
- We executed a resource adequacy agreement for all of the capacity from our Pastoria power plant with Southern California Edison for 2012 and 2013.

In addition to the above, we believe that upgrades and expansions to our current assets offer proven and financially disciplined opportunities to improve our operations, capacity and efficiencies. We are in the process of upgrading certain of our turbines to increase our generation and efficiencies beginning in the fourth quarter of 2009 and extending through 2013 with estimated additional capital expenditures of approximately $100 million.

Cash Flow Activities — The following table summarizes our cash flow activities for the nine months ended September 30, 2009 and 2008 (in millions):

	Nine Months Ended September 30,	
	2009	2008
Beginning cash and cash equivalents	$ 1,657	$ 1,915
Net cash provided by (used in):		
Operating activities	537	355
Investing activities	(164)	534
Financing activities	(1,117)	(1,953)
Net decrease in cash and cash equivalents	(744)	(1,064)
Ending cash and cash equivalents	$ 913	$ 851

Net Cash Provided By Operating Activities

Cash flows provided by operating activities for the nine months ended September 30, 2009, improved to $537 million compared to $355 million for the nine months ended September 30, 2008. Our improvement in cash flows provided by operating activities was primarily due to:

- Interest paid — Cash paid for interest decreased by $310 million, to $563 million for the nine months ended September 30, 2009, as compared to $873 million for the same period in 2008, primarily due to the repayment of the Second Priority Debt, the one-time payments of post-petition interest of $135 million related to pre-emergence debt and $27 million in post-petition interest paid by our Canadian subsidiaries as a result of our emergence from Chapter 11 on January 31, 2008 and, to a lesser extent, lower interest rates for the comparable period in 2009.
- Reorganization costs — Cash payments for reorganization items decreased by $119 million.

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

- Gross profit — Gross profit, excluding unrealized changes in mark-to-market activity, depreciation expense and loss on disposal of assets, decreased by $28 million for the nine months ended September 30, 2009, as compared to the same period in 2008. This was primarily attributable to lower Commodity Margin largely due to lower natural gas prices and lower Market Heat Rates, which was partially offset by the positive impact of our hedging activities and higher Market Heat Rates in the Southeast.
- Working capital — Working capital employed increased by approximately $202 million for the 2009 period compared to the 2008 period, after adjusting for debt-related balances and derivative activities, which did not impact cash provided by operating activities. The increase was primarily due to a reduction in assets held for sale for the nine months ended September 30, 2008.
- Debt extinguishment costs — Cash payments for debt extinguishment costs in the 2009 period were $40 million related to the CCFC Refinancing, compared to cash payments of $6 million related to the refinancing of Blue Spruce and Metcalf for the comparable period in 2008.
- Cash taxes – Cash received for tax refunds was $43 million for the nine months ended September 30, 2009 compared to $78 million for the nine months ended September 30, 2008, a decrease of $35 million. The decrease in refunds was partially offset by cash paid for taxes, which was $6 million for the nine months ended September 30, 2009 compared to $16 million for the nine months ended September 30, 2008, a decrease of $10 million.

Net Cash Provided By (Used In) Investing Activities

Cash flows used in investing activities for the nine months ended September 30, 2009, were $164 million compared to cash flows provided by investing activities of $534 million for the nine months ended September 30, 2008. The decrease in cash flows from investing activities was primarily due to:

- Sale of power plants, turbines and investments — We had no significant asset sales in 2009 compared to $398 million of cash received from the sales of the Fremont and Hillabee development projects in 2008.
- Reconsolidation of the Canadian Debtors and other deconsolidated foreign entities — In 2008, we had a favorable cash effect of $64 million from the reconsolidation of the Canadian Debtors and other deconsolidated foreign entities.
- Return of investment from unconsolidated investments — For the nine months ended September 30, 2009, we received distributions of nil compared to $26 million for the nine months ended September 30, 2008.
- Capital expenditures — Net capital expenditures (capital expenditures offset by proceeds from asset disposals) increased by $48 million in 2009 resulting from our maintenance programs and environmental upgrades.
- Restricted cash requirements — Restricted cash increased $2 million in 2009, compared to a favorable $145 million decrease for the same period in 2008.

Net Cash Used In Financing Activities

Due to our emergence from Chapter 11 during the first quarter of 2008, our financing activities are not directly comparable. Cash flows used in financing activities for the nine months ended September 30, 2009, resulted in outflows of approximately $1.1 billion compared to outflows of approximately $2.0 billion for the same period in 2008. Our significant 2009 and 2008 financing transactions are described below:

- During the nine months ended September 30, 2009, we had net cash borrowings of approximately $1.0 billion from the issuance of the CCFC New Notes and from the refinancing of Deer Park, and we repaid $725 million previously drawn under our First Lien Credit Facility revolver, $779 million of CCFC Old Notes and CCFC Term Loans and $300 million of CCFC Preferred Shares. We also made scheduled repayments of approximately $45 million under the First Lien Credit Facility term loans and $260 million on notes payable, other project debt and capital lease obligations.
- During the 2008 period, we borrowed approximately $3.6 billion under our First Lien Facilities and used that borrowing and cash on hand to repay approximately $3.7 billion of the Second Priority Debt, $1.1 billion on the First Lien Credit Facility revolver, $300 million on the Bridge Facility, and $128 million of First Lien Credit Facility term loans under our First Lien Facilities. In addition, we received proceeds of $355 million from refinancing Metcalf and Blue Spruce and repaid $567 million of other project financing, capital leases and notes payable.
- We incurred finance costs of $34 million in 2009 to facilitate an amendment to our First Lien Credit Facility and for the CCFC and Deer Park refinancings. During the nine months ended September 30, 2008, we incurred $207 million of financing costs primarily related to the closing on our First Lien Facilities.
- We received $70 million from the settlement of derivatives with an other-than-insignificant financing element for the nine months ended September 30, 2008.

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, Power Contract Financing , L.L.C., Power Contract Financing III, LLC, 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.), CCFCP, and Russell City Energy Company, LLC.

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 include physical commodity contracts and financial commodity instruments such as swaps, 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 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 exposed to commodity price movements (both profits and losses) in connection with these transactions. These positions are included in and subject to our consolidated risk management portfolio position limits and controls structure. Changes in fair value of commodity positions that do not qualify for either hedge accounting or the normal purchase normal sale exemption are recognized currently in earnings in mark-to-market activity within operating revenues in the case of power transactions, and within fuel and purchased energy expense, in the case of natural gas transactions. Our future hedged status, and marketing and optimization activities are subject to change as determined by our commercial operations group, Chief Risk Officer, Risk Management Committee of senior management and Board of Directors.

We have economically hedged a substantial portion of our generation and natural gas portfolio mostly through power and natural gas forward physical and financial transactions for the remainder of 2009 and much of 2010. 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 September 30, 2009, the maximum length of our PPAs extends 24 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 3 and 17 years, respectively. Assuming constant September 30, 2009, power and natural gas prices and interest rates, we estimate that pre-tax net losses of $46 million would be reclassified from AOCI into earnings during the next 12 months as the hedged transactions settle; however, the actual amounts that will be reclassified will vary based on changes in natural gas and power prices as well as interest rates. Therefore, we are unable to predict what the actual reclassification from AOCI 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 futures, forwards, options, fixed for floating swaps, instruments that settle on power price to natural gas price relationships (Heat Rate swaps and 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 require 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, counterparty credit risk and changes in interest rates. Because 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 decreased to $2.3 billion and $(2.5) billion at September 30, 2009, compared to $4.1 billion and $(4.5) billion at December 31, 2008, respectively. As of September 30, 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 and nine months ended September 30, 2009, have reflected this as discussed below.

The change in fair value of our outstanding commodity and interest rate derivative instruments from January 1, 2009, through September 30, 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 recognized or otherwise settled during the period	128(1)	198(2)	326
Fair value attributable to new contracts	(2)	(116)	(118)
Changes in fair value attributable to price movements	(7)	90	83
Changes in fair value attributable to nonperformance risk	(48)	(1)	(49)
Fair value of contracts outstanding at September 30, 2009(3)	$ (381)	$ 183	$ (198)

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(1) Interest rate settlements consist of recognized losses from interest rate cash flow hedges of $(116) million and recognized losses from undesignated interest rate swaps of $(12) million (represents a portion of interest expense as reported on our Consolidated Condensed Statements of Operations).

(2) Settlement of commodity contracts not designated as hedging instruments of $(134) million (represents a portion of operating revenues and fuel and purchased energy expense as reported on our Consolidated Condensed Statements of Operations) and $(64) million related to recognition of gains from cash flow hedges, previously reflected in OCI, offset by other changes in derivative assets and liabilities not reflected in OCI or net income.

(3) Net commodity and interest rate derivative assets and liabilities reported in Notes 7 and 8 of the Notes to Consolidated 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) from our commodity instruments and interest rate swaps for the three and nine months ended September 30, 2009 and 2008, are outlined below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Realized gain (loss)(1)	$ (2)	$ (33)	$ (27)	$ (101)
Unrealized gain (loss)	44	47	67	(16)
Total mark-to-market gain (loss)	$ 42	$ 14	$ 40	$ (117)

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(1) Balance includes a non-cash gain from amortization of prepaid power sales agreements of approximately $13 million and $33 million for the three and nine months ended September 30, 2008, respectively.

Our change in AOCI from an accumulated loss of $(158) million at December 31, 2008, to an accumulated loss of $(250) million at September 30, 2009, was primarily driven by the effect of a decrease in power and natural gas prices, reclassification adjustment for cash flow hedges realized in net income, a decrease 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 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 and non-derivative instruments.

The fair value of outstanding derivative commodity instruments at September 30, 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	$ 123	$ (223)	$ —	$ —	$ (100)
Prices provided by other external sources	149	121	12	—	282
Prices based on models and other valuation methods	—	—	—	1	1
Total fair value	$ 272	$ (102)	$ 12	$ 1	$ 183

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 and nine months ended September 30, 2009 and 2008, as well as our VAR at September 30, 2009 and 2008 (in millions):

	2009	2008
Three months ended September 30:		
High	$ 50	$ 66
Low	$ 36	$ 44
Average	$ 44	$ 57
Nine months ended September 30:		
High	$ 59	$ 70
Low	$ 36	$ 39
Average	$ 49	$ 52
As of September 30	$ 45	$ 47

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.

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 September 30, 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 September 30, 2009)	2009	2010-2011	2012-2013	After 2013	Total
Investment grade	$ 272	$ (100)	$ 14	$ —	$ 186
Non-investment grade	—	(2)	(2)	—	(4)
No external ratings	—	—	—	1	1
Total fair value	$ 272	$ (102)	$ 12	$ 1	$ 183

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 September 30, 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. As of September 30, 2009, approximately $11 million was recorded in AOCI for interest rate swaps that were hedging the variable interest rates on the retired First Lien Credit Facility term loans, which were exchanged for First Lien Notes on October 21, 2009. We expect that these interest rate swaps will no longer qualify as cash flow hedges.

The issuance of our First Lien Notes and our CCFC Refinancing have reduced our exposure to fluctuating interest rates by refinancing approximately $2.3 billion in variable interest rate debt (including our CCFCP Preferred Shares) with $2.2 billion of fixed interest rate debt. The following table summarizes the contract terms as well as the fair values of our significant financial instruments exposed to interest rate risk as of September 30, 2009. All outstanding balances and fair market values are shown gross of applicable premium or discount, if any (in millions):

	2009	2010	2011	2012	2013	Thereafter	Total	Fair Value September 30, 2009
Debt by Maturity Date:								
Fixed Rate	$ 4	$ 217	$ 71	$ 21	$ 24	$ 1,132	$ 1,469	$ 1,453
Average Interest Rate	9.5%	6.5%	6.9%	9.6%	9.6%	7.9%		
Variable Rate	$ 19	$ 184	$ 960	$ 207	$ 77	$ 5,910	$ 7,357	$ 6,757
Average Interest Rate(1)	2.9%	3.6%	3.7%	4.5%	4.6%	6.5%		

(1) Projection based upon anticipated LIBOR rates.

New Accounting Requirements and Disclosures

See Note 1 of the Notes to Consolidated Condensed Financial Statements for a discussion of new accounting requirements and disclosures.

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 third 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 14 of the Notes to Consolidated Condensed Financial Statements for a description of our legal proceedings.

Item 1A. ***Risk Factors***

Various risk factors could have a negative effect on our business, financial position, cash flows and results of operations. These include the following risk factors, in addition to the risk factors set forth in "Item 1A. Risk Factors" in our 2008 Form 10-K:

Existing and future anticipated GHG/Carbon legislation could adversely affect our operations.

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

In 2009, ten states in the northeast began the compliance period of a cap-and-trade program, RGGI, to regulate CO_2 emissions from power plants. California is in the process of creating implementation plans for Assembly Bill 32 which places a statewide cap on GHG emissions and requires the state to return to 1990 emission levels by 2020.

In 2008, there were several bills introduced in the U.S. Congress concerning climate change. On June 26, 2009, the House of Representatives passed The American Clean Energy and Security Act of 2009, a climate change and clean energy bill, which, among other provisions, would establish an economy-wide carbon cap-and-trade program and set carbon emission reduction targets in several sectors of the economy, including the power sector. For the power sector, 2012 is set as the initial year for compliance. On October 23, 2009, draft climate change legislation entitled the Clean Energy Jobs and American Power Act, was released in the Senate. The legislation is similar to The American Clean Energy and Security Act of 2009 in that it also includes, among other provisions, an economy-wide carbon cap-and-trade program.

If either bill were to become law, we would have the obligation to obtain emissions allowances for the operation of our fossil-fuel power plants. While we expect the costs to acquire allowances to be a factor that will impact market price, there can be no assurance that market price will fully reflect these costs which could adversely affect our Commodity Margin. With respect to our existing long-term steam and power contracts under which we would not be able to recover costs to acquire allowances from our customers, the bill allocates a pool of free allowances to generators with qualifying contracts to mitigate such costs. However, there can be no assurance there will be a sufficient number of free allowances in the pool to fully cover emissions related to generation under such contracts which could adversely impact our Commodity Margin.

Although we cannot predict the effect and ultimate content of final climate change legislation and regulations, if any, on our business, we continue to expect climate change legislation efforts to proceed at the federal level, and that proposed legislation will take the form of a cap-and-trade program, although it is possible that legislation may take other forms, such as a carbon tax on each unit of CO_2 or GHG emitted in excess of mandated limits. As a result of requirements for GHG emissions reduction, we could be required under any climate change legislation or related regulations ultimately enacted to purchase allowances or offsets to emit GHGs or other regulated pollutants or to pay taxes on such emissions. These requirements, as well as the possibility that market or contract prices will not fully reflect costs of compliance, or that we may not be able to obtain free allowances or recoup our costs to obtain allowances or to reduce emissions, could have a material impact on our business or results of operations.

Claims that some geothermal plants cause increased risk of seismic activity could delay or increase the cost of further development at The Geysers.

In 2009, as part of a joint private and federally-funded geothermal technology research project, a company unrelated to us commenced deepening an existing geothermal well on a property neighboring our Geysers Assets in northern California, and reportedly was attempting to drill into the hot, low or non-permeable base rock that underlies the existing geothermal steam reservoir at The Geysers to engineer or create a "multilayered heat extraction system" below the reservoir by injecting water under very high pressure, fracturing the rock. While there is general agreement that the operation of certain geothermal plants may cause low level seismic activity, the fracturing of deep bedrock caused by the multilayered heat extraction system is believed to create a greater risk of more serious seismic activity and has spawned public and political concern due to this risk. As a consequence, in June 2009, the Department of Energy began requiring all geothermal research grant applicants to comply with a published seismic mitigation protocol, and, in July 2009, the Department of Energy temporarily halted funding of its portion of that research project pending further seismicity studies. Although our geothermal operations do not include attempts to engineer or create new reservoirs from hot, low or non-permeable rock, the concerns regarding induced seismicity from geothermal operations could delay or otherwise adversely impact our Department of Energy grant applications. In addition, it is possible that government entities or agencies will seek to more stringently regulate the exploration, development and operation of geothermal facilities, including operations of our Geysers Assets, in order to mitigate induced seismicity resulting from geothermal operations, or that operators of geothermal power plants could be subject to property damage claims resulting from increased seismic activity. Any of these events could increase the cost of operating the existing Geysers Assets and may delay or increase further exploration and any further development of our Geysers Assets.

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 third quarter of 2009, we withheld a total of 27,642 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
July	—	$ —	—	n/a
August	27,642	$ 13.00	—	n/a
September	—	$ —	—	n/a
Total	27,642	$ 13.00	—	n/a

Item 6. ***Exhibits***

The following exhibits are filed herewith unless otherwise indicated:

EXHIBIT INDEX

Exhibit Number	Description
1.1	Underwriting Agreement, dated September 22, 2009, among Calpine Corporation, the selling stockholder named therein and Morgan Stanley & Co. Incorporated, the underwriter named therein (incorporated by reference to Exhibit 1.1 to our Current Report on Form 8-K/A filed with the SEC on September 23, 2009).
3.1	Amended and Restated Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed with the SEC on February 1, 2008).
3.2	Amended and Restated Bylaws of the Company (as amended through May 7, 2009) (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, filed with the SEC on July 31, 2009).
4.1	Indenture, dated October 21, 2009, between Calpine Corporation and Wilmington Trust Company, as trustee, including form of 7.25% senior secured notes due 2017 (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed with the SEC on October 26, 2009).
10.1	Credit Agreement, dated as of January 31, 2008, among Calpine Corporation, as borrower, Goldman Sachs Credit Partners L.P., Credit Suisse, Deutsche Bank Securities Inc. and Morgan Stanley Senior Funding, Inc., as co-documentation agents and as co-syndication agents, General Electric Capital Corporation, as sub-agent for the revolving lenders, Goldman Sachs Credit Partners L.P., as administrative agent and as collateral agent and each of the financial institutions from time to time party thereto (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on February 1, 2008).
10.2	First Amendment to Credit Agreement and Second Amendment to Collateral Agency and Intercreditor Agreement, dated as of August 20, 2009, among Calpine Corporation, certain of Calpine Corporation's subsidiaries as guarantors, the financial institutions party thereto as lenders and Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent. (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed with the SEC on August 26, 2009).
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.

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: October 29, 2009

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

Date: October 29, 2009

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10.2	First Amendment to Credit Agreement and Second Amendment to Collateral Agency and Intercreditor Agreement, dated as of August 20, 2009, among Calpine Corporation, certain of Calpine Corporation's subsidiaries as guarantors, the financial institutions party thereto as lenders and Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent. (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed with the SEC on August 26, 2009).
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* Filed herewith.

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: October 29, 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: October 29, 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 September 30, 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: October 29, 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.