CALPINE CORP
Form 10-Q
May 02, 2013

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

Form 10-Q
(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2013

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) 830-2000
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. Yes [X] No [ ]

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

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

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

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

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

Indicate the number of shares outstanding of each of the registrant’s classes of common stock, as of the latest practicable date: 455,255,545 shares of common stock, par value $0.001, were outstanding as of April 30, 2013.

CALPINE CORPORATION AND SUBSIDIARIES
REPORT ON FORM 10-Q
For the Quarter Ended March 31, 2013
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DEFINITIONS

As used in this report for the quarter ended March 31, 2013 (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
2012 Form 10-K	Calpine Corporation's Annual Report on Form 10-K for the year ended December 31, 2012, filed with the SEC on February 12, 2013.
2017 First Lien Notes	The $1.2 billion aggregate principal amount of 7.25% senior secured notes due 2017, issued October 21, 2009, of which 10% of the aggregate principal amount was redeemed on November 7, 2012 in connection with the issuance of the 2019 First Lien Term Loan
2018 First Lien Term Loans	Collectively, the $1.3 billion first lien senior secured term loan dated March 9, 2011 and the $360 million first lien senior secured term loan dated June 17, 2011
2019 First Lien Notes	The $400 million aggregate principal amount of 8.0% senior secured notes due 2019, issued May 25, 2010, of which 10% of the aggregate principal amount was redeemed on November 7, 2012 in connection with the issuance of the 2019 First Lien Term Loan
2019 First Lien Term Loan	The $835 million first lien senior secured term loan, dated October 9, 2012, among Calpine Corporation, as borrower, and the lenders party hereto, and Morgan Stanley Senior Funding, Inc., as administrative agent and Goldman Sachs Credit Partners L.P., as collateral agent
2020 First Lien Notes	The $1.1 billion aggregate principal amount of 7.875% senior secured notes due 2020, issued July 23, 2010, of which 10% of the aggregate principal amount was redeemed on November 7, 2012 in connection with the issuance of the 2019 First Lien Term Loan
2021 First Lien Notes	The $2.0 billion aggregate principal amount of 7.50% senior secured notes due 2021, issued October 22, 2010, of which 10% of the aggregate principal amount was redeemed on November 7, 2012 in connection with the issuance of the 2019 First Lien Term Loan
2023 First Lien Notes	The $1.2 billion aggregate principal amount of 7.875% senior secured notes due 2023, issued January 14, 2011, of which 10% of the aggregate principal amount was redeemed on November 7, 2012 in connection with the issuance of the 2019 First Lien Term Loan
AB 32	California Assembly Bill 32
Adjusted EBITDA	EBITDA as adjusted for the effects of (a) impairment charges, (b) major maintenance expense, (c) operating lease expense, (d) unrealized gains or losses on commodity derivative mark-to-market activity, (e) adjustments to reflect only

	the Adjusted EBITDA from our unconsolidated investments, (f) stock-based compensation expense, (g) gains or losses on sales, dispositions or retirements of assets, (h) non-cash gains and losses from foreign currency translations, (i) gains or losses on the repurchase or extinguishment of debt and (j) other extraordinary, unusual or non-recurring items
AOCI	Accumulated Other Comprehensive Income
Average availability	Represents the total hours during the period that our plants were in-service or available for service as a percentage of the total hours in the period
Average capacity factor, excluding peakers	A measure of total actual generation as a percent of total potential generation. It is calculated by dividing (a) total MWh generated by our power plants, excluding peakers, by (b) the product of multiplying (i) the average total MW in operation, excluding peakers, during the period by (ii) the total hours in the period
Broad River	Broad River Energy LLC, formerly an indirect, wholly-owned subsidiary of Calpine that leases the Broad River Energy Center, an 847 MW natural gas-fired, peaking power plant located in Gaffney, South Carolina, from the BR Owner Lessors

ABBREVIATION	DEFINITION
BR Owner Lessors	Broad River OL-1, LLC, a Delaware limited liability company, Broad River OL-2, LLC, a Delaware limited liability company, Broad River OL-3, LLC, a Delaware limited liability company, and Broad River OL-4, LLC, a Delaware limited liability company, each of which is an indirect, wholly-owned subsidiary of Calpine Corporation, which lease the Broad River Energy Center (i) from Cherokee County, South Carolina and (ii) to Broad River
Btu	British thermal unit(s), a measure of heat content
CAA	Federal Clean Air Act, U.S. Code Title 42, Chapter 85
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
Calpine Equity Incentive Plans	Collectively, the Director Plan and the Equity Plan, which provide for grants of equity awards to Calpine non-union employees and non-employee members of Calpine’s Board of Directors
Cap-and-trade	A government imposed emissions reduction program that would place a cap on the amount of emissions that can be emitted from certain sources, such as power plants. In its simplest form, the cap amount is set as a reduction from the total emissions during a base year and for each year over a period of years the cap amount would be reduced to achieve the targeted overall reduction by the end of the period. Allowances or credits for emissions in an amount equal to the cap would be issued or auctioned to companies with facilities, permitting them to emit up to a certain amount of emissions during each applicable period. After allowances have been distributed or auctioned, they can be transferred or traded
CARB	California Air Resources Board
CCFC	Calpine Construction Finance Company, L.P., an indirect, wholly-owned subsidiary of Calpine
CCFC Finance	CCFC Finance Corp.
CCFC Notes	The $1.0 billion aggregate principal amount of 8.0% senior secured notes due 2016, issued May 19, 2009, by CCFC and CCFC Finance
CDHI	Calpine Development Holdings, Inc., an indirect, wholly-owned subsidiary of Calpine
Chapter 11	Chapter 11 of the U.S. Bankruptcy Code
CO2	Carbon dioxide
COD	Commercial operations date

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 expense	The sum of our expenses from fuel and purchased energy expense, fuel transportation expense, transmission expense, environmental compliance expense and realized settlements from our marketing, hedging and optimization activities including natural gas transactions hedging future power sales, but excludes the unrealized portion of our mark-to-market activity

ABBREVIATION	DEFINITION
Commodity Margin	Non-GAAP financial measure that includes power and steam revenues, sales of purchased power and physical natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, environmental compliance expense, and realized settlements from our marketing, hedging and optimization activities including natural gas transactions hedging future power sales, 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 physical natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and realized settlements from our marketing, hedging and optimization activities, but excludes the unrealized portion of our mark-to-market activity
Company	Calpine Corporation, a Delaware corporation, and its subsidiaries
Corporate Revolving Facility	The $1.0 billion aggregate amount revolving credit facility credit agreement, dated as of December 10, 2010, among Calpine Corporation, Goldman Sachs Bank USA, as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, the lenders party thereto and the other parties thereto
CPUC	California Public Utilities Commission
Creed	Creed Energy Center, LLC
Director Plan	The Amended and Restated Calpine Corporation 2008 Director Incentive Plan
Dodd-Frank Act	The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
EBITDA	Net income (loss) attributable to Calpine before net (income) loss attributable to the noncontrolling interest, interest, taxes, depreciation and amortization
EPA	U.S. Environmental Protection Agency
Equity Plan	The Amended and Restated Calpine Corporation 2008 Equity Incentive Plan
ERCOT	Electric Reliability Council of Texas
Exchange Act	U.S. Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FDIC	U.S. Federal Deposit Insurance Corporation
FERC	U.S. Federal Energy Regulatory Commission
First Lien Credit Facility	Credit Agreement, dated as of January 31, 2008, as amended by the First Amendment to Credit Agreement and Second Amendment to Collateral Agency

	and Intercreditor Agreement, dated as of August 20, 2009, among Calpine Corporation, as borrower, certain subsidiaries of the Company named therein, as guarantors, the lenders party thereto, Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent, and the other agents named therein
First Lien Notes	Collectively, the 2017 First Lien Notes, the 2019 First Lien Notes, the 2020 First Lien Notes, the 2021 First Lien Notes and the 2023 First Lien Notes
First Lien Term Loans	Collectively, the 2018 First Lien Term Loans and the 2019 First Lien Term Loan

ABBREVIATION	DEFINITION
GE	General Electric International, Inc.
Geysers Assets	Our geothermal power plant assets, including our steam extraction and gathering assets, located in northern California consisting of 15 operating power plants and one plant not in operation
GHG(s)	Greenhouse gas(es), primarily carbon dioxide (CO2), and including methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs)
Goose Haven	Goose Haven Energy Center, LLC
Greenfield LP	Greenfield Energy Centre LP, a 50% partnership interest between certain of our subsidiaries and a third party which operates the Greenfield Energy Centre, a 1,038 MW natural gas-fired, combined-cycle power plant in Ontario, Canada
Heat Rate(s)	A measure of the amount of fuel required to produce a unit of power
IOUs	Investor Owned Utilities
IRS	U.S. Internal Revenue Service
ISO(s)	Independent System Operator(s)
KWh	Kilowatt hour(s), a measure of power produced, purchased or sold
LIBOR	London Inter-Bank Offered Rate
Market Heat Rate(s)	The regional power price divided by the corresponding regional natural gas price
MMBtu	Million Btu
MW	Megawatt(s), a measure of plant capacity
MWh	Megawatt hour(s), a measure of power produced, purchased or sold
NAAQS	National Ambient Air Quality Standards
NOL(s)	Net operating loss(es)
NOX	Nitrogen oxides
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OTC	Over-the-Counter

PG&E	Pacific Gas & Electric Company
PJM	PJM Interconnection is a RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia

ABBREVIATION	DEFINITION
PPA(s)	Any term power purchase agreement or other contract for a physically settled sale (as distinguished from a financially settled future, option or other derivative or hedge transaction) of any power product, including power, capacity and/or ancillary services, in the form of a bilateral agreement or a written or oral confirmation of a transaction between two parties to a master agreement, including sales related to a tolling transaction in which the purchaser provides the fuel required by us to generate such power and we receive a variable payment to convert the fuel into power and steam
PUCT	Public Utility Commission of Texas
PUHCA 2005	U.S. Public Utility Holding Company Act of 2005
PURPA	U.S. Public Utility Regulatory Policies Act of 1978
QF(s)	Qualifying facility(ies), which are cogeneration facilities and certain small power production facilities eligible to be “qualifying facilities” under PURPA, provided that they meet certain power and thermal energy production requirements and efficiency standards. QF status provides an exemption from the books and records requirement of PUHCA 2005 and grants certain other benefits to the QF
REC(s)	Renewable energy credit(s)
Reserve margin(s)	The measure of how much the total generating capacity installed in a region exceeds the peak demand for power in that region
Risk Management Policy	Calpine’s policy applicable to all employees, contractors, representatives and agents which defines the risk management framework and corporate governance structure for commodity risk, interest rate risk, currency risk and other risks
RPS	Renewable Portfolio Standards
RTO(s)	Regional Transmission Organization(s)
SEC	U.S. Securities and Exchange Commission
Securities Act	U.S. Securities Act of 1933, as amended
SO2	Sulfur dioxide
Spark Spread(s)	The difference between the sales price of power per MWh and the cost of fuel to produce it
Steam Adjusted Heat Rate	The adjusted Heat Rate for our natural gas-fired power plants, excluding peakers, calculated by dividing (a) the fuel consumed in Btu reduced by the net equivalent Btu in steam exported to a third party by (b) the KWh generated. Steam Adjusted Heat Rate is a measure of fuel efficiency, so the lower our Steam Adjusted Heat Rate, the lower our cost of generation

TCEQ	Texas Commission on Environmental Quality
TSR	Total shareholder return

ABBREVIATION	DEFINITION
U.S. GAAP	Generally accepted accounting principles in the U.S.
VAR	Value-at-risk
VIE(s)	Variable interest entity(ies)
Whitby	Whitby Cogeneration Limited Partnership, a 50% partnership interest between certain of our subsidiaries and a third party which operates Whitby, a 50 MW natural gas-fired, simple-cycle cogeneration power plant located in Ontario, Canada

Forward-Looking Statements

In addition to historical information, this Report contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act, and Section 21E of the Exchange Act. Forward-looking statements may appear throughout this Report, including without limitation, the "Management's Discussion and Analysis" section. We use words such as "believe," "intend," "expect," "anticipate," "plan," "may," "will," "sh "estimate," "potential," "project" and similar expressions to identify forward-looking statements. Such statements include, among others, those concerning our expected financial performance and strategic and operational plans, as well as all assumptions, expectations, predictions, intentions or beliefs about future events. You are cautioned that any such forward-looking statements are not guarantees of future performance and that a number of risks and uncertainties could cause actual results to differ materially from those anticipated in the forward-looking statements. Such risks and uncertainties include, but are not limited to:

- Financial results that may be volatile and may not reflect historical trends due to, among other things, fluctuations in prices for commodities such as natural gas and power, changes in U.S. macroeconomic conditions, fluctuations in liquidity and volatility in the energy commodities markets and our ability to hedge risks;
- Laws, regulation and market rules in the markets in which we participate and our ability to effectively respond to changes in laws, regulations or market rules or the interpretation thereof including those related to the environment, derivative transactions and market design in the regions in which we operate;
- Our ability to manage our liquidity needs and to comply with covenants under our First Lien Notes, Corporate Revolving Facility, First Lien Term Loans, CCFC Notes and other existing financing obligations;
- Risks associated with the operation, construction and development of power plants including unscheduled outages or delays and plant efficiencies;
- Risks related to our geothermal resources, including the adequacy of our steam reserves, unusual or unexpected steam field well and pipeline maintenance requirements, variables associated with the injection of wastewater to the steam reservoir and potential regulations or other requirements related to seismicity concerns that may delay or increase the cost of developing or operating geothermal resources;
- The unknown future impact on our business from the Dodd-Frank Act and the rules to be promulgated thereunder;
- Competition, including risks associated with marketing and selling power in the evolving energy markets;
- The expiration or early termination of our PPAs and the related results on revenues;
- Future capacity revenues may not occur at expected levels;
- Natural disasters, such as hurricanes, earthquakes and floods, acts of terrorism or cyber attacks that may impact our power plants or the markets our power plants serve and our corporate headquarters;
- Disruptions in or limitations on the transportation of natural gas, fuel oil and transmission of power;
- Our ability to manage our customer and counterparty exposure and credit risk, including our commodity positions;
- Our ability to attract, motivate and retain key employees;
- Present and possible future claims, litigation and enforcement actions; and
- Other risks identified in this Report and in our 2012 Form 10-K.

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

Where You Can Find Other Information

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

PART I — FINANCIAL INFORMATION
Item 1. Financial Statements

CALPINE CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31,	
	2013	2012
	(in millions, except share and per share amounts)	
Operating revenues:		
Commodity revenue	$1,308	$1,212
Unrealized mark-to-market gain (loss)	(71)	22
Other revenue	4	2
Operating revenues	1,241	1,236
Operating expenses:		
Fuel and purchased energy expense:		
Commodity expense	835	691
Unrealized mark-to-market (gain)	(14)	(56)
Fuel and purchased energy expense	821	635
Plant operating expense	227	221
Depreciation and amortization expense	146	140
Sales, general and other administrative expense	33	33
Other operating expenses	18	21
Total operating expenses	1,245	1,050
(Income) from unconsolidated investments in power plants	(8)	(9)
Income from operations	4	195
Interest expense	176	185
Loss on interest rate derivatives	—	14
Interest (income)	(2)	(3)
Debt extinguishment costs	—	12
Other (income) expense, net	5	2
Loss before income taxes	(175)	(15)
Income tax benefit	(50)	(6)
Net loss	(125)	(9)
Net income attributable to the noncontrolling interest	—	—
Net loss attributable to Calpine	$(125)	$(9)
Basic and diluted loss per common share attributable to Calpine:		
Weighted average shares of common stock outstanding (in thousands)	451,706	478,106
Net loss per common share attributable to Calpine — basic and diluted	$(0.28)	$(0.02)

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

CALPINE CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF COMPREHENSIVE LOSS
(Unaudited)

	Three Months Ended March 31,	
	2013	2012
	(in millions)	
Net loss	$(125)	$(9)
Cash flow hedging activities:		
Gain on cash flow hedges before reclassification adjustment for cash flow hedges realized in net loss	4	10
Reclassification adjustment for (gain) loss on cash flow hedges realized in net loss	9	(10)
Foreign currency translation gain (loss)	(2)	3
Income tax benefit	1	2
Other comprehensive income	12	5
Comprehensive loss	(113)	(4)
Comprehensive (income) attributable to the noncontrolling interest	—	—
Comprehensive loss attributable to Calpine	$(113)	$(4)

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

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CALPINE CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	March 31, 2013	December 31, 2012
	(in millions, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents ($151 and $109 attributable to VIEs)	$962	$1,284
Accounts receivable, net of allowance of $2 and $6	483	437
Margin deposits and other prepaid expense	303	244
Restricted cash, current ($63 and $53 attributable to VIEs)	142	193
Derivative assets, current	514	339
Inventory and other current assets	352	335
Total current assets	2,756	2,832
Property, plant and equipment, net ($4,226 and $4,192 attributable to VIEs)	13,052	13,005
Restricted cash, net of current portion ($56 and $59 attributable to VIEs)	57	60
Investments in power plants	92	81
Long-term derivative assets	149	98
Other assets	463	473
Total assets	$16,569	$16,549
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$437	$382
Accrued interest payable	134	180
Debt, current portion ($81 and $39 attributable to VIEs)	144	115
Derivative liabilities, current	595	357
Other current liabilities	203	284
Total current liabilities	1,513	1,318
Debt, net of current portion ($2,682 and $2,660 attributable to VIEs)	10,633	10,635
Long-term derivative liabilities	289	293
Other long-term liabilities	257	247
Total liabilities	12,692	12,493
Commitments and contingencies (see Note 10)		
Stockholders' equity:		
Preferred stock, $0.001 par value per share; authorized 100,000,000 shares, none issued and outstanding	—	—
Common stock, $0.001 par value per share; authorized 1,400,000,000 shares, 494,762,280 and 492,495,100 shares issued, respectively, and 455,000,065 and 457,048,970 shares outstanding, respectively	1	1
Treasury stock, at cost, 39,762,215 and 35,446,130 shares, respectively	(675)	(594)
Additional paid-in capital	12,351	12,335
Accumulated deficit	(7,625)	(7,500)
Accumulated other comprehensive loss	(236)	(248)
Total Calpine stockholders' equity	3,816	3,994

Noncontrolling interest	61	62
Total stockholders' equity	3,877	4,056
Total liabilities and stockholders' equity	$16,569	$16,549

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

CALPINE CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31,	
	2013	2012
	(in millions)	
Cash flows from operating activities:		
Net loss	$(125)	$(9)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation and amortization expense[1]	158	151
Deferred income taxes	(7)	(1)
Loss on disposition of assets	2	2
Unrealized mark-to-market activity, net	55	(224)
(Income) from unconsolidated investments in power plants	(8)	(9)
Stock-based compensation expense	8	6
Other	(2)	—
Change in operating assets and liabilities:		
Accounts receivable	(45)	211
Derivative instruments, net	(36)	(66)
Other assets	(73)	20
Accounts payable and accrued expenses	(91)	(153)
Settlement of non-hedging interest rate swaps	—	151
Other liabilities	7	(8)
Net cash provided by (used in) operating activities	(157)	71
Cash flows from investing activities:		
Purchases of property, plant and equipment	(176)	(181)
Settlement of non-hedging interest rate swaps	—	(151)
Decrease in restricted cash	54	23
Purchases of deferred transmission credits	—	(8)
Other	—	3
Net cash used in investing activities	(122)	(314)
Cash flows from financing activities:		
Repayment under First Lien Term Loans	(6)	(4)
Borrowings from project financing, notes payable and other	73	114
Repayments of project financing, notes payable and other	(36)	(34)
Financing costs	(9)	(5)
Stock repurchases	(75)	(6)
Proceeds from exercises of stock options	9	—
Other	1	(4)
Net cash provided by (used in) financing activities	(43)	61
Net decrease in cash and cash equivalents	(322)	(182)
Cash and cash equivalents, beginning of period	1,284	1,252
Cash and cash equivalents, end of period	$962	$1,070

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

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CALPINE CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS — (CONTINUED)
(Unaudited)

	Three Months Ended March 31,	
	2013	2012
	(in millions)	
Cash paid during the period for:		
Interest, net of amounts capitalized	$213	$226
Income taxes	$5	$6
Supplemental disclosure of non-cash investing activities:		
Change in capital expenditures included in accounts payable	$17	$47

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(1) Includes depreciation and amortization included in fuel and purchased energy 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
March 31, 2013
(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

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

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 normal, recurring 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 U.S. 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, 2012, included in our 2012 Form 10-K. The results for interim periods are not necessarily indicative of the results for the entire year primarily due to acquisitions and disposals of assets, seasonal fluctuations in our revenues, timing of major maintenance expense, variations resulting from the application of the method to calculate the provision for income tax for interim periods, volatility of commodity prices and unrealized gains and losses from commodity and interest rate derivative contracts.

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

Reclassification — We reclassified environmental compliance expense previously recorded in other operating expenses of $3 million to Commodity expense on our Consolidated Condensed Statements of Operations for the three months ended March 31, 2012 to conform to the current period presentation. We also reclassified repayments under First Lien Term Loans previously reported in repayments of project financing, notes payable and other of $4 million within our cash flows provided by financing activities on our Consolidated Condensed Statements of Cash Flows for the three months ended March 31, 2012 to conform to the current period presentation.

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 March 31, 2013 and December 31, 2012, we had cash and cash equivalents of $176 million and $131 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 is restricted. These amounts are held by depository banks in order to comply with the contractual provisions requiring reserves for payments such as for debt service, rent, major maintenance and debt repurchases or with applicable regulatory requirements. Funds that can be used to satisfy obligations due during the next 12 months are classified as current restricted cash, with the remainder classified as non-current restricted cash. Restricted cash is generally invested in accounts earning market rates; therefore, the carrying value approximates fair value. Such cash is excluded from cash and cash equivalents on our Consolidated Condensed Balance Sheets and Statements of Cash Flows.

The table below represents the components of our restricted cash as of March 31, 2013 and December 31, 2012 (in millions):

	March 31, 2013			December 31, 2012		
	Current	Non-Current	Total	Current	Non-Current	Total
Debt service[(1)]	$11	$41	$52	$11	$41	$52
Rent reserve	3	—	3	—	—	—
Construction/major maintenance	30	10	40	32	14	46
Security/project/insurance	69	3	72	101	3	104
Other	29	3	32	49	2	51
Total	$142	$57	$199	$193	$60	$253

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(1) At March 31, 2013 and December 31, 2012, amounts restricted for debt service included approximately $24 million and $25 million, respectively, of repurchase agreements with a financial institution containing maturity dates greater than one year.

Inventory — At March 31, 2013 and December 31, 2012, we had inventory of $299 million and $301 million, respectively. Inventory primarily consists of spare parts, stored natural gas and fuel oil, emission reduction credits and natural gas exchange imbalances. Inventory, other than spare parts, is stated primarily at the lower of cost or market value under the weighted average cost method. Spare parts inventory is valued at weighted average cost and is expensed to plant operating expense or capitalized to property, plant and equipment as the parts are utilized and consumed.

Property, Plant and Equipment, Net — At March 31, 2013 and December 31, 2012, the components of property, plant and equipment are stated at cost less accumulated depreciation as follows (in millions):

	March 31, 2013	December 31, 2012	Depreciable Lives
Buildings, machinery and equipment	$14,783	$14,774	3 – 47 Years
Geothermal properties	1,248	1,243	13 – 59 Years
Other	155	142	3 – 47 Years
	16,186	16,159	
Less: Accumulated depreciation	4,516	4,390	
	11,670	11,769	
Land	98	98	
Construction in progress	1,284	1,138	
Property, plant and equipment, net	$13,052	$13,005	

Capitalized Interest — The total amount of interest capitalized was $12 million and $8 million for the three months ended March 31, 2013 and 2012, respectively.

Treasury Stock — During the three months ended March 31, 2013, we repurchased common stock with a value of $75 million under our previously announced share repurchase program and withheld shares with a value of $6 million to satisfy tax withholding obligations associated with the vesting of restricted stock awarded to employees under the Equity Plan.

New Accounting Standards and Disclosure Requirements

Disclosures about Offsetting Assets and Liabilities — In December 2011, the FASB issued Accounting Standards Update 2011-11, “Balance Sheet - Disclosures about Offsetting Assets and Liabilities” to enhance disclosure requirements relating to the offsetting of assets and liabilities on an entity’s balance sheet. The update requires enhanced disclosures regarding assets and liabilities that are presented net or gross in the statement of financial position when the right of offset exists, or that are subject to an enforceable master netting arrangement. In January 2013, the FASB issued Accounting Standards Update 2013-01, “Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities” to provide clarification that the scope previously defined in Accounting Standards Update 2011-11 applies to derivatives, repurchase agreements, reverse repurchase agreements and securities borrowing and lending transactions that are subject to an enforceable master netting arrangement or similar agreement. The new disclosure requirements relating to these updates are retrospective and effective for annual and interim periods beginning on or

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after January 1, 2013. We adopted Accounting Standards Updates 2011-11 and 2013-01 as of January 1, 2013. As these updates only required additional disclosures, adoption of these standards did not have a material impact on our financial condition, results of operations or cash flows. See Note 5 for disclosures regarding our assets and liabilities that are presented gross on our Consolidated Condensed Balance Sheets when the right of offset exists, or that are subject to an enforceable master netting arrangement.

Comprehensive Income — In February 2013, the FASB issued Accounting Standards Update 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income" to amend the reporting of reclassifications out of AOCI to require an entity to report the effect of significant reclassifications out of AOCI on the respective line items in net income if the amount reclassified is required under U.S. GAAP to be reclassified in its entirety to net income in the same reporting period. An entity shall provide this information together in one location, either on the face of the statement where net income is presented, or as a separate disclosure in the notes to the financial statements. The new disclosure requirements relating to this update are prospective and effective for interim and annual periods beginning after December 15, 2012, with early adoption permitted. We adopted Accounting Standards Update 2013-02 as of January 1, 2013. As this update only required additional disclosures, adoption of this standard did not have a material impact on our financial condition, results of operations or cash flows. See Note 5 for disclosures on the affect of significant reclassifications out of AOCI on the respective line items on our Consolidated Condensed Statements of Operations.

2. Variable Interest Entities and Unconsolidated Investments in Power Plants

We consolidate all of our VIEs where we have determined that we are the primary beneficiary. There were no changes to our determination of whether we are the primary beneficiary of our VIEs for the three months ended March 31, 2013. See Note 5 in our 2012 Form 10-K for further information regarding our VIEs.

VIE Disclosures

Our consolidated VIEs include natural gas-fired power plants with an aggregate capacity of 8,255 MW at both March 31, 2013 and December 31, 2012. For these VIEs, we may provide other operational and administrative support through various affiliate contractual arrangements among the VIEs, Calpine Corporation and its other wholly owned subsidiaries whereby we support the VIE through the reimbursement of costs and/or the purchase and sale of energy. In addition to amounts contractually required, Calpine Corporation provided support to these VIEs in the form of cash and other contributions of nil during each of the three months ended March 31, 2013 and 2012.

U.S. GAAP requires separate disclosure on the face of our Consolidated Condensed Balance Sheets of the significant assets of a consolidated VIE that can be used only to settle obligations of the consolidated VIE and the significant liabilities of a consolidated VIE for which creditors (or beneficial interest holders) do not have recourse to the general credit of the primary beneficiary. In determining which assets of our VIEs meet the separate disclosure criteria, we consider that this separate disclosure requirement is met where Calpine Corporation is substantially limited or prohibited from access to assets (primarily cash and cash equivalents, restricted cash and property, plant and equipment), and where our VIEs had project financing that prohibits the VIE from providing guarantees on the debt of others. In determining which liabilities of our VIEs meet the separate disclosure criteria, we consider that this separate disclosure requirement is met where there are agreements that prohibit the debt holders of the VIEs from recourse to the general credit of Calpine Corporation and where the amounts were material to our financial statements.

Unconsolidated VIEs and Investments in Power Plants

We have a 50% partnership interest in Greenfield LP and in Whitby. Greenfield LP and Whitby are also VIEs; however, we do not have the power to direct the most significant activities of these entities and therefore do not consolidate them. We account for these entities under the equity method of accounting and include our net equity interest in investments in power plants on our Consolidated Condensed Balance Sheets. At March 31, 2013 and December 31, 2012, our equity method investments included on our Consolidated Condensed Balance Sheets were comprised of the following (in millions):

	Ownership Interest as of March 31, 2013	March 31, 2013	December 31, 2012

Greenfield LP	50%	$76	$69
Whitby	50%	16	12
Total investments in power plants		$92	$81

Our risk of loss related to our unconsolidated VIEs is limited to our investment balance. Holders of the debt of our unconsolidated investments do not have recourse to Calpine Corporation and its other subsidiaries; therefore, the debt of our

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unconsolidated investments is not reflected on our Consolidated Condensed Balance Sheets. At March 31, 2013 and December 31, 2012, equity method investee debt was approximately $432 million and $448 million, respectively, and based on our pro rata share of each of the investments, our share of such debt would be approximately $216 million and $224 million at March 31, 2013 and December 31, 2012, respectively.

Our equity interest in the net income from Greenfield LP and Whitby for the three months ended March 31, 2013 and 2012, is recorded in (income) from unconsolidated investments in power plants. The following table sets forth details of our (income) from unconsolidated investments in power plants for the periods indicated (in millions):

	Three Months Ended March 31,	
	2013	2012
Greenfield LP	$(4)	$(6)
Whitby	(4)	(3)
Total	$(8)	$(9)

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 1,038 MW natural gas-fired, combined-cycle power plant located in Ontario, Canada. We and Mitsui & Co., Ltd. each hold a 50% interest in Greenfield LP. Greenfield LP holds an 18-year term loan with an original principal 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%. Distributions from Greenfield LP were nil during each of the three months ended March 31, 2013 and 2012.

Whitby — Whitby is a limited partnership between certain of our subsidiaries and Atlantic Packaging Ltd., which operates the Whitby facility, a 50 MW natural gas-fired, simple-cycle cogeneration power plant located in Ontario, Canada. We and Atlantic Packaging Ltd. each hold a 50% partnership interest in Whitby. Distributions from Whitby were nil during each of the three months ended March 31, 2013 and 2012.

Inland Empire Energy Center Put and Call Options — We hold a call option to purchase the Inland Empire Energy Center (a 775 MW natural gas-fired power plant located in California which achieved COD on May 3, 2010) from GE that may be exercised between years 2017 and 2024. GE holds a put option whereby they can require us to purchase the power plant, if certain plant performance criteria are met by 2025. We determined that we are not the primary beneficiary of the Inland Empire power plant, and we do not consolidate it due to the fact that GE directs the most significant activities of the power plant including operations and maintenance.

3. Debt

At March 31, 2013 and December 31, 2012, our debt was as follows (in millions):

	March 31, 2013	December 31, 2012
First Lien Notes	$5,304	$5,303
First Lien Term Loans	2,456	2,463
Project financing, notes payable and other	1,826	1,789
CCFC Notes	980	978
Capital lease obligations	211	217
Total debt	10,777	10,750
Less: Current maturities	144	115
Debt, net of current portion	$10,633	$10,635

Our annual effective interest rate on our consolidated debt, excluding the impacts of capitalized interest and unrealized gains (losses) on interest rate swaps, decreased to 7.0% for the three months ended March 31, 2013, from 7.4% for the three months ended March 31, 2012. The issuance of our 2019 First Lien Term Loan in October 2012 allowed us to reduce our overall cost of debt by replacing a portion of our First Lien Notes and variable rate project debt with a corporate level term loan carrying a lower variable interest rate. Also, in February 2013, we repriced our First Lien Term Loans by lowering the LIBOR floor by 0.25% to 1.0% and lowering the LIBOR margin by 0.25% to 3.0%.

First Lien Notes

Our First Lien Notes are summarized in the table below (in millions):

	March 31, 2013	December 31, 2012
2017 First Lien Notes	$1,080	$1,080
2019 First Lien Notes	360	360
2020 First Lien Notes	984	983
2021 First Lien Notes	1,800	1,800
2023 First Lien Notes	1,080	1,080
Total First Lien Notes	$5,304	$5,303

First Lien Term Loans

Our First Lien Term Loans are summarized in the table below (in millions):

	March 31, 2013	December 31, 2012
2018 First Lien Term Loans	$1,625	$1,630
2019 First Lien Term Loan	831	833
Total First Lien Term Loans	$2,456	$2,463

CCFC Refinancing

On April 22, 2013, we announced that CCFC, our indirect, wholly-owned subsidiary, is pursuing a potential debt refinancing whereby CCFC will enter into a new senior secured term loan and the funds will be used to repay the CCFC Notes. The timing, size and terms of any potential refinancing and the use of proceeds thereof are subject to market and other conditions and we make no assurance that such actions will take place.

Corporate Revolving Facility and Other Letters of Credit Facilities

The table below represents amounts issued under our letter of credit facilities at March 31, 2013 and December 31, 2012 (in millions):

	March 31, 2013	December 31, 2012
Corporate Revolving Facility[1]	$222	$243
CDHI	250	253
Various project financing facilities	131	130
Total	$603	$626

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(1) The Corporate Revolving Facility represents our primary revolving facility.

CDHI

We have a $300 million letter of credit facility related to CDHI. As a result of the completion of the sale of Riverside Energy Center, LLC, a wholly-owned subsidiary of CDHI, on December 31, 2012, we are required to cash collateralize letters of credit issued in excess of $225 million until replacement collateral is contributed to the CDHI collateral package, which we are in the process of arranging. At March 31, 2013, we had $25 million in outstanding letters of credit issued in excess of $225 million under our CDHI letter of credit facility that were collateralized by cash. We do not expect this change to have a material impact on our liquidity.

Fair Value of Debt

We record our debt instruments based on contractual terms, net of any applicable premium or discount. We did not elect to apply the alternative U.S. GAAP provisions of the fair value option for recording financial assets and financial liabilities. The following table details the fair values and carrying values of our debt instruments at March 31, 2013 and December 31, 2012 (in millions):

	March 31, 2013		December 31, 2012	
	Fair Value	Carrying Value	Fair Value	Carrying Value
First Lien Notes	$5,801	$5,304	$5,863	$5,303
First Lien Term Loans	2,486	2,456	2,489	2,463
Project financing, notes payable and other(1)	1,661	1,691	1,599	1,629
CCFC Notes	1,050	980	1,075	978
Total	$10,998	$10,431	$11,026	$10,373

(1) Excludes a lease that is accounted for as a failed sale-leaseback transaction under U.S. GAAP.

We measure the fair value of our First Lien Notes, First Lien Term Loans and CCFC Notes using market information, including quoted market prices or dealer quotes for the identical liability when traded as an asset (categorized as level 2). We measure the fair value of our project financing, notes payable and other debt instruments using discounted cash flow analyses based on our current borrowing rates for similar types of borrowing arrangements (categorized as level 3). We do not have any debt instruments with fair value measurements categorized as level 1 within the fair value hierarchy.

4. Assets and Liabilities with Recurring Fair Value Measurements

Cash Equivalents — Highly liquid investments which meet the definition of cash equivalents, primarily investments in money market accounts, are included in both our cash and cash equivalents and our restricted cash on our Consolidated Condensed Balance Sheets. Certain of our money market accounts invest in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. Government, its agencies or instrumentalities. Our cash equivalents are classified within level 1 of the fair value hierarchy.

Margin Deposits and Margin Deposits Posted with Us by Our Counterparties — Margin deposits and margin deposits posted with us by our counterparties represent cash collateral paid between our counterparties and us to support our commodity contracts. Our margin deposits and margin deposits posted with us by our counterparties are generally cash and cash equivalents and are classified within level 1 of the fair value hierarchy.

Derivatives — The primary factors affecting the fair value of our derivative instruments at any point in time are the volume of open derivative positions (MMBtu, MWh and $ notional amounts); changing commodity market prices, primarily for power and natural gas; our credit standing and that of our counterparties for energy commodity derivatives; and prevailing interest rates for our interest rate swaps. Prices for power and natural gas and interest rates are volatile, which can result in material changes in the fair value measurements reported in our financial statements in the future.

We utilize market data, such as pricing services and broker quotes, and assumptions that we believe market participants would use in pricing our assets or liabilities including assumptions about 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. We use other qualitative assessments to determine the level of activity in any given market. We primarily apply the market approach and income approach for recurring fair value measurements and utilize what we believe to be the best available information. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observability of those inputs.

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

Our level 1 fair value derivative instruments primarily consist of power and natural gas swaps, futures and options traded on the NYMEX or Intercontinental Exchange.
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 market sources such as the Intercontinental Exchange and Bloomberg. To the extent we obtain prices from brokers in the marketplace, we have procedures in place to ensure that prices represent executable prices for market participants. In certain instances, our level 2 derivative instruments may utilize models to measure fair value. These models are primarily industry-standard models that incorporate various assumptions, including quoted interest rates, correlation, volatility, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.
Our level 3 fair value derivative instruments may consist of 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 option-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.
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 our estimate of the fair value of our assets and liabilities and their placement within the fair value hierarchy levels. The following tables present our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2013 and December 31, 2012, by level within the fair value hierarchy:

	Assets and Liabilities with Recurring Fair Value Measures as of March 31, 2013			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Cash equivalents[1]	$ 1,124	$ —	$ —	$ 1,124
Margin deposits	257	—	—	257
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	594	—	—	594
Commodity forward contracts[2]	—	43	21	64
Interest rate swaps	—	5	—	5
Total assets	$ 1,975	$ 48	$ 21	$ 2,044
Liabilities:				
Margin deposits posted with us by our counterparties	$ 1	$ —	$ —	$ 1
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	655	—	—	655
Commodity forward contracts[2]	—	33	8	41
Interest rate swaps	—	188	—	188
Total liabilities	$ 656	$ 221	$ 8	$ 885

	Assets and Liabilities with Recurring Fair Value Measures as of December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Cash equivalents[1]	$1,502	$—	$—	$1,502
Margin deposits	196	—	—	196
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	385	—	—	385
Commodity forward contracts[2]	—	24	24	48
Interest rate swaps	—	4	—	4
Total assets	$2,083	$28	$24	$2,135
Liabilities:				
Margin deposits posted with us by our counterparties	$11	$—	$—	$11
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	424	—	—	424
Commodity forward contracts[2]	—	18	8	26
Interest rate swaps	—	200	—	200
Total liabilities	$435	$218	$8	$661

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(1) As of March 31, 2013 and December 31, 2012, we had cash equivalents of $952 million and $1,274 million included in cash and cash equivalents and $172 million and $228 million included in restricted cash, respectively.
(2) Includes OTC swaps and options.

At March 31, 2013 and December 31, 2012, the derivative instruments classified as level 3 primarily included a longer-term OTC traded commodity contract extending through 2014. This contract is classified as level 3 because the contract terms exceed the period for which liquid market rate information is available. As such, the fair value of the contract incorporates extrapolation assumptions made in the determination of the market price for future delivery periods in which applicable commodity prices were either not observable or lacked corroborative market data. The fair value of the net derivative position classified as level 3 is predominantly driven by market commodity prices; however, given the nature of our net derivative position, we do not believe that a significant change in market commodity prices would have a material impact on our level 3 net fair value. The following table presents quantitative information for the unobservable inputs used in our most significant level 3 fair value measurements at March 31, 2013 and December 31, 2012:

	Quantitative Information about Level 3 Fair Value Measurements			
	March 31, 2013			
	Fair Value, Net Asset (Liability)	Valuation Technique	Significant Unobservable Input	Range
	(in millions)			
Physical Power	$8	Discounted cash flow	Market price (per MWh)	$31.75 — $56/MWh
	December 31, 2012			
	Fair Value, Net Asset (Liability)	Valuation Technique	Significant Unobservable Input	Range
	(in millions)			
Physical Power	$11	Discounted cash flow	Market price (per MWh)	$23.75 — $53.82/MWh

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The following table sets forth a reconciliation of changes in the fair value of our net derivative assets (liabilities) classified as level 3 in the fair value hierarchy for the periods indicated (in millions):

	Three Months Ended March 31,	
	2013	2012
Balance, beginning of period	$16	$17
Realized and unrealized gains (losses):		
Included in net loss:		
Included in operating revenues[1]	1	10
Included in fuel and purchased energy expense[2]	—	(4)
Included in OCI	—	4
Purchases, issuances and settlements:		
Purchases	—	1
Issuances	—	(1)
Settlements	(3)	(6)
Transfers in and/or out of level 3[3]:		
Transfers into level 3[4]	—	—
Transfers out of level 3[5]	(1)	(4)
Balance, end of period	$13	$17
Change in unrealized gains relating to instruments still held at end of period	$1	$6

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(1) For power contracts and Heat Rate swaps and options, included on our Consolidated Condensed Statements of Operations.

(2) For natural gas contracts, swaps and options, included on our Consolidated Condensed Statements of Operations.

(3) We transfer amounts among levels of the fair value hierarchy as of the end of each period. There were no transfers into or out of level 1 during the three months ended March 31, 2013 and 2012.

(4) There were no transfers out of level 2 into level 3 for the three months ended March 31, 2013 and 2012.

(5) We had $1 million and $4 million in gains transferred out of level 3 into level 2 for the three months ended March 31, 2013 and 2012, respectively, due to changes in market liquidity in various power markets.

5. Derivative Instruments

Types of Derivative Instruments and Volumetric Information

Commodity Instruments — We are exposed to changes in prices for the purchase and sale of power, natural gas and other energy commodities. We use derivatives, which include physical commodity contracts and financial commodity instruments such as OTC and exchange traded swaps, futures, options, forward agreements and instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) or instruments that settle on power price relationships between delivery points for the purchase and sale of power and natural gas to attempt to maximize the risk-adjusted returns by economically hedging a portion of the commodity price risk associated with our assets. By entering into these transactions, we are able to economically hedge a portion of our Spark Spread at estimated generation and prevailing price levels.

Interest Rate Swaps — A portion of our debt is indexed to base rates, primarily LIBOR. We have historically used interest rate swaps to adjust the mix between fixed and floating rate debt to hedge our interest rate risk for potential adverse changes in interest rates. As of March 31, 2013, the maximum length of time over which we were hedging using interest rate derivative instruments designated as cash flow hedges was 11 years.

As of March 31, 2013 and December 31, 2012, the net forward notional buy (sell) position of our outstanding commodity and interest rate swap contracts that did not qualify under the normal purchase normal sale exemption were as follows (in millions):

Derivative Instruments	Notional Amounts	
	March 31, 2013	December 31, 2012
Power (MWh)	(16)	(16)
Natural gas (MMBtu)	162	66
Interest rate swaps	$1,599	$1,602

Certain of our derivative instruments contain credit risk-related contingent provisions that require us to maintain collateral balances consistent with our credit ratings. If our credit rating were to be downgraded, it could require us to post additional collateral or could potentially allow our counterparty to request immediate, full settlement on certain derivative instruments in liability positions. Currently, we do not believe that it is probable that any additional collateral posted as a result of a one credit notch downgrade from its current level would be material. The aggregate fair value of our derivative liabilities with credit risk-related contingent provisions as of March 31, 2013, was $6 million for which we have posted collateral of $1 million by posting margin deposits or granting additional first priority liens on the assets currently subject to first priority liens under our First Lien Notes, First Lien Term Loans and Corporate Revolving Facility. However, if our credit rating were downgraded by one notch from its current level, we estimate that no additional collateral would be required and that no counterparty could request immediate, full settlement.

Accounting for Derivative Instruments

We recognize all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for, and we elect, the normal purchase normal sale exemption. For transactions in which we elect the normal purchase normal sale exemption, gains and losses are not reflected on our Consolidated Condensed Statements of Operations until the period of delivery. In order to simplify our reporting, we elected to discontinue the application of hedge accounting treatment during the first quarter of 2012 for all commodity derivatives, including the remaining commodity derivatives previously accounted for as cash flow hedges. Accordingly, prospective changes in fair value from the date of this election are reflected in unrealized mark-to-market gain/loss on our Consolidated Condensed Statements of Operations and could create more volatility in our earnings. Revenues and fuel costs derived from instruments that qualified for hedge accounting or represent an economic hedge are recorded in the same financial statement line item as the item being hedged. Although we have discontinued the application of hedge accounting treatment for our commodity derivative instruments, prior to this change and for our interest rate swaps, 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 (or economically hedged) within operating activities or investing activities (in the case of settlements for our interest rate swaps formerly hedging our First Lien Credit Facility term loans) 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 recognized currently in earnings and are separately stated on our Consolidated Condensed Statements of Operations in unrealized mark-to-market gain/loss as a component of operating revenues (for power contracts and swaps) and fuel and purchased energy expense (for natural gas contracts and swaps). Gains and losses due to ineffectiveness on interest rate hedging instruments are recognized currently in earnings as a component of interest expense (for interest rate swaps except as discussed below). If it is determined that the forecasted transaction is no longer probable of occurring, then hedge accounting will be discontinued prospectively and future changes in fair value are recorded in earnings. If the hedging instrument is terminated or de-designated prior to the occurrence of the hedged forecasted transaction, the net accumulated gain or loss associated with the changes in fair value of the hedge instrument remains deferred in AOCI until such time as the forecasted

transaction impacts earnings or until it is determined that the forecasted transaction is probable of not occurring.
Derivatives Not Designated as Hedging Instruments — We enter into power, natural gas and interest rate transactions that primarily act as economic hedges to our asset and interest rate portfolio, but either do not qualify as hedges under the hedge accounting guidelines or qualify under the hedge accounting guidelines and the hedge accounting designation has not been elected. Changes in fair value of commodity derivatives not designated as hedging instruments are recognized currently in earnings and are separately stated on our Consolidated Condensed Statements of Operations in unrealized mark-to-market gain/loss as a

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component of operating revenues (for power contracts and Heat Rate swaps and options) and fuel and purchased energy expense (for natural gas contracts, swaps and options). Changes in fair value of interest rate derivatives not designated as hedging instruments are recognized currently in earnings as interest expense (for interest rate swaps except as discussed below).

Interest Rate Swaps Formerly Hedging our First Lien Credit Facility — On March 26, 2012, we terminated the legacy interest rate swaps formerly hedging our First Lien Credit Facility and recorded the fair value of the swaps totaling approximately $156 million. Approximately $14 million of the settlement amount was recorded as a component of loss on interest rate derivatives on our Consolidated Condensed Statement of Operations for the three months ended March 31, 2012, and approximately $142 million reflected the realization of losses recorded in prior periods.

Derivatives Included on Our Consolidated Condensed Balance Sheets

During the first quarter of 2012, we de-designated our remaining commodity derivative cash flow hedges; therefore, as of March 31, 2013 and December 31, 2012, we do not have any designated commodity derivative cash flow hedges. The following tables present the fair values of our net derivative instruments recorded on our Consolidated Condensed Balance Sheets by location and hedge type at March 31, 2013 and December 31, 2012 (in millions):

	March 31, 2013		
	Commodity Instruments	Interest Rate Swaps	Total Derivative Instruments
Balance Sheet Presentation			
Current derivative assets	$514	$—	$514
Long-term derivative assets	144	5	149
Total derivative assets	$658	$5	$663
Current derivative liabilities	$551	$44	$595
Long-term derivative liabilities	145	144	289
Total derivative liabilities	$696	$188	$884
Net derivative liabilities	$(38)	$(183)	$(221)

	December 31, 2012		
	Commodity Instruments	Interest Rate Swaps	Total Derivative Instruments
Balance Sheet Presentation			
Current derivative assets	$339	$—	$339
Long-term derivative assets	94	4	98
Total derivative assets	$433	$4	$437
Current derivative liabilities	$317	$40	$357
Long-term derivative liabilities	133	160	293
Total derivative liabilities	$450	$200	$650
Net derivative liabilities	$(17)	$(196)	$(213)

	March 31, 2013		December 31, 2012	
	Fair Value of Derivative Assets	Fair Value of Derivative Liabilities	Fair Value of Derivative Assets	Fair Value of Derivative Liabilities
Derivatives designated as cash flow hedging instruments:				
Interest rate swaps	$5	$174	$4	$184
Total derivatives designated as cash flow hedging instruments	$5	$174	$4	$184
Derivatives not designated as hedging instruments:				
Commodity instruments	$658	$696	$433	$450
Interest rate swaps	—	14	—	16
Total derivatives not designated as hedging instruments	$658	$710	$433	$466
Total derivatives	$663	$884	$437	$650

We elected not to offset fair value amounts recognized as derivative instruments on our Consolidated Condensed Balance Sheets that are executed with the same counterparty under master netting arrangements or other contractual netting provisions negotiated with the counterparty. Our netting arrangements include a right to set off or net together purchases and sales of similar products in the margining or settlement process. In some instances, we have also negotiated cross commodity netting rights which allow for the net presentation of activity with a given counterparty regardless of product purchased or sold. We also post cash collateral in support of our derivative instruments which may also be subject to a master netting arrangement with the same counterparty. The tables below set forth our net exposure to derivative instruments after offsetting amounts subject to a master netting arrangement with the same counterparty at March 31, 2013 and December 31, 2012 (in millions):

	March 31, 2013			
		Gross Amounts Not Offset on the Consolidated Condensed Balance Sheets		
	Gross Amounts Presented on our Consolidated Condensed Balance Sheets	Derivative Asset (Liability) not Offset on the Consolidated Condensed Balance Sheets	Margin/Cash (Received) Posted [1]	Net Amount
Derivative assets:				
Commodity exchange traded futures and swaps contracts	$594	$(593)	$(1)	$—
Commodity forward contracts	64	(29)	—	35
Interest rate swaps	5	—	—	5
Total derivative assets	$663	$(622)	$(1)	$40
Derivative (liabilities):				
Commodity exchange traded futures and swaps contracts	$(655)	$593	$62	$—
Commodity forward contracts	(41)	29	1	(11)
Interest rate swaps	(188)	—	—	(188)
Total derivative (liabilities)	$(884)	$622	$63	$(199)
Net derivative assets (liabilities)	$(221)	$—	$62	$(159)

	December 31, 2012			
		Gross Amounts Not Offset on the Consolidated Condensed Balance Sheets		
	Gross Amounts Presented on our Consolidated Condensed Balance Sheets	Derivative Asset (Liability) not Offset on the Consolidated Condensed Balance Sheets	Margin/Cash (Received) Posted [1]	Net Amount
Derivative assets:				
Commodity exchange traded futures and swaps contracts	$385	$(379)	$(6)	$—
Commodity forward contracts	48	(17)	(1)	30
Interest rate swaps	4	—	—	4
Total derivative assets	$437	$(396)	$(7)	$34
Derivative (liabilities):				
Commodity exchange traded futures and swaps contracts	$(424)	$379	$45	$—
Commodity forward contracts	(26)	17	1	(8)
Interest rate swaps	(200)	—	—	(200)
Total derivative (liabilities)	$(650)	$396	$46	$(208)
Net derivative assets (liabilities)	$(213)	$—	$39	$(174)

(1) Negative balances represent margin deposits posted with us by our counterparties related to our derivative activities that are subject to a master netting arrangement. Positive balances reflect margin deposits and natural gas and power prepayments posted by us with our counterparties related to our derivative activities that are subject to a master netting arrangement. See Note 6 for a further discussion of our collateral.

Derivatives Included on Our Consolidated Condensed Statements of Operations

Changes in the fair values of our derivative instruments (both assets and liabilities) are reflected either in cash for option premiums paid or collected, in OCI, net of tax, for the effective portion of derivative instruments which qualify for and we have elected cash flow hedge accounting treatment, or on our Consolidated Condensed Statements of Operations as a component of mark-to-market activity within our earnings.

The following tables detail the components of our total mark-to-market activity for both the net realized gain (loss) and the net unrealized gain (loss) recognized from our derivative instruments in earnings and where these components were recorded on our Consolidated Condensed Statements of Operations for the periods indicated (in millions):

	Three Months Ended March 31,	
	2013	2012
Realized gain (loss)[1]		
Commodity derivative instruments	$28	$118
Interest rate swaps	—	(157)
Total realized gain (loss)	$28	$(39)
Unrealized gain (loss)[2]		
Commodity derivative instruments	$(57)	$78
Interest rate swaps	2	146

Total unrealized gain (loss)	$(55)	$224
Total mark-to-market activity, net	$(27)	$185

(1) Does not include the realized value associated with derivative instruments that settle through physical delivery.
(2) In addition to changes in market value on derivatives not designated as hedges, changes in unrealized gain (loss) also includes hedge ineffectiveness and adjustments to reflect changes in credit default risk exposure.

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	Three Months Ended March 31,	
	2013	2012
Realized and unrealized gain (loss)		
Derivatives contracts included in operating revenues	$(74)	$92
Derivatives contracts included in fuel and purchased energy expense	45	104
Interest rate swaps included in interest expense	2	3
Loss on interest rate derivatives	—	(14)
Total mark-to-market activity, net	$(27)	$185

Derivatives Included in OCI and AOCI

The following table details the effect of our net derivative instruments that qualified for hedge accounting treatment and are included in OCI and AOCI for the periods indicated (in millions):

	Three Months Ended March 31, Gain (Loss) Recognized in OCI (Effective Portion)		Three Months Ended March 31, Gain (Loss) Reclassified from AOCI into Income (Effective Portion)[3]		
	2013	2012	2013	2012	Affected Line Item on the Consolidated Condensed Statements of Operations
Commodity derivative instruments[1]:					
Power derivative instruments	$—	$(15)	$—	$38	Commodity revenue
Natural gas derivative instruments	—	14	—	(21)	Commodity expense
Interest rate swaps[2]	13	1	(9)	(7)	Interest expense
Total	$13	$—	$(9)	$10	

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(1) There were no commodity derivative instruments designated as cash flow hedges during the three months ended March 31, 2013. We recorded a gain on hedge ineffectiveness of $2 million related to our commodity derivative instruments designated as cash flow hedges during the three months ended March 31, 2012.

(2) We did not record any gain (loss) on hedge ineffectiveness related to our interest rate swaps designated as cash flow hedges during the three months ended March 31, 2013 and 2012.

(3) Cumulative cash flow hedge losses, net of tax, remaining in AOCI were $228 million and $242 million at March 31, 2013 and December 31, 2012, respectively.

We estimate that pre-tax net losses of $45 million would be reclassified from AOCI into interest expense 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 interest rates. Therefore, we are unable to predict what the actual reclassification from AOCI into earnings (positive or negative) will be for the next 12 months.

6. 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 various debt agreements as collateral under certain of our power and natural gas agreements 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 share the benefits of the collateral subject to such first priority liens pro rata with the lenders under our various debt agreements.

The table below summarizes the balances outstanding under margin deposits, natural gas and power prepayments, and exposure under letters of credit and first priority liens for commodity procurement and risk management activities as of March 31, 2013 and December 31, 2012 (in millions):

	March 31, 2013	December 31, 2012
Margin deposits(1)	$257	$196
Natural gas and power prepayments	35	35
Total margin deposits and natural gas and power prepayments with our counterparties(2)	$292	$231
Letters of credit issued	$486	$484
First priority liens under power and natural gas agreements	5	14
First priority liens under interest rate swap agreements	194	206
Total letters of credit and first priority liens with our counterparties	$685	$704
Margin deposits posted with us by our counterparties(1)(3)	$1	$11
Letters of credit posted with us by our counterparties	2	1
Total margin deposits and letters of credit posted with us by our counterparties	$3	$12

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(1) Balances are subject to master netting arrangements and presented on a gross basis on our Consolidated Condensed Balance Sheets. We do not offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement for financial statement presentation, and we do not offset amounts recognized for the right to reclaim, or the obligation to return, cash collateral with corresponding derivative instrument fair values. See Note 5 for further discussion of our derivative instruments subject to master netting arrangements.

(2) At March 31, 2013 and December 31, 2012, $273 million and $211 million, respectively, were included in margin deposits and other prepaid expense and $19 million and $20 million, respectively, were included in other assets on our Consolidated Condensed Balance Sheets.

(3) 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.

7. Income Taxes

Income Tax Benefit

The table below shows our consolidated income tax benefit from continuing operations (excluding noncontrolling interest) and our effective tax rates for the periods indicated (in millions):

	Three Months Ended March 31,	
	2013	2012
Income tax benefit	$(50)	$(6)
Effective tax rate	29%	40%

Income Tax Audits — We remain subject to periodic audits and reviews by 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 would likely result in a reduction of deferred tax assets rather than a cash payment of income taxes.

Canadian Tax Audits — In January 2013, we received an adjusted reassessment on one of two transfer pricing issues that we are disputing with the Canadian Revenue Authority ("CRA") and are currently evaluating the merits of the adjusted reassessment. If accepted, any adjustments to our transfer pricing would increase taxable income and would be offset entirely by existing NOL's to which a valuation allowance has been applied. Any interest assessments resulting from acceptance of the CRA offer would be immaterial.

We continue to evaluate the remaining proposed adjustments received on our other Canadian subsidiary; however, based on our current analysis which is supported by our tax advisors, we believe that our transfer pricing positions and policies are appropriate, and we intend to challenge the CRA's proposed adjustments. If we are unsuccessful in our challenge, any adjustment to Canadian taxable income would first be offset against the existing NOLs that are available; however, we do not believe any reassessment resulting in an adjustment to taxable income which is greater than our existing NOLs, or including interest or penalties which cannot be offset by existing NOLs, would have a material adverse effect on our financial condition, results of operations or cash flows.

Valuation Allowance — U.S. GAAP requires that we consider all available evidence, both positive and negative, and tax planning strategies to determine whether, based on the weight of that evidence, a valuation allowance is needed to reduce the value of deferred tax assets. Future realization of the tax benefit of an existing deductible temporary difference or carryforward ultimately depends on the existence of sufficient taxable income of the appropriate character within the carryback or carryforward periods available under the tax law. Due to our history of losses, we were unable to assume future profits; however, since our emergence from Chapter 11, we are able to consider available tax planning strategies.

Unrecognized Tax Benefits — At March 31, 2013, we had unrecognized tax benefits of $79 million. If recognized, $24 million of our unrecognized tax benefits could impact the annual effective tax rate and $55 million, related to deferred tax assets, could be offset against the recorded valuation allowance resulting in no impact to our effective tax rate. We also had accrued interest and penalties of $14 million for income tax matters at March 31, 2013. We recognize interest and penalties related to unrecognized tax benefits in income tax benefit on our Consolidated Condensed Statements of Operations. We believe it is reasonably possible that a decrease within the range of approximately nil and $5 million in unrecognized tax benefits could occur within the next 12 months primarily related to state and foreign tax issues.

8. Loss per Share

We 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. As we incurred a net loss for each of the three months ended March 31, 2013 and 2012, diluted loss per share for both periods is computed on the same basis as basic loss per share, as the inclusion of any other potential shares outstanding would be anti-dilutive.

We excluded the following items from diluted loss per common share for the three months ended March 31, 2013 and 2012, because they were anti-dilutive (shares in thousands):

	Three Months Ended March 31,	
	2013	2012
Share-based awards	10,963	15,650

9. Stock-Based Compensation

Calpine Equity Incentive Plans

The Calpine Equity Incentive Plans provide for the issuance of equity awards to all non-union 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 share-based awards. The equity awards granted under the Calpine Equity Incentive Plans include both graded and cliff vesting awards which vest over periods between one and five years, contain contractual terms between approximately five and ten years and are subject to forfeiture provisions under certain circumstances, including termination of employment prior to vesting. At March 31, 2013, there were 567,000 and 27,533,000 shares of our common stock authorized for issuance to participants under the Director Plan and the Equity Plan, respectively.

Equity Classified Share-Based Awards

We use the Black-Scholes option-pricing model or the Monte Carlo simulation model, as appropriate, to estimate the fair value of our employee stock options on the grant date, which takes into account the exercise price and expected term of the stock option, the current price of the underlying stock and its expected volatility, expected dividends on the stock and the risk-free interest rate for the expected term of the stock option as of the grant date. For our restricted stock and restricted stock units, we use our closing stock price on the date of grant, or the last trading day preceding the grant date for restricted stock granted on non-trading days, as the fair value for measuring compensation expense. Stock-based compensation expense is recognized over the period in which the related employee services are rendered. The service period is generally presumed to begin on the grant date and end when the equity award is fully vested. We use the graded vesting attribution method to recognize fair value of the equity award over the service period. For example, the graded vesting attribution method views one three-year option grant with annual graded vesting as three separate sub-grants, each representing 33 1/3% of the total number of stock options granted. The first sub-grant vests over one year, the second sub-grant vests over two years and the third sub-grant vests over three years. A three-year option grant with cliff vesting is viewed as one grant vesting over three years.

Stock-based compensation expense recognized was $8 million and $6 million for the three months ended March 31, 2013 and 2012, respectively. We did not record any significant 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 months ended March 31, 2013 and 2012. At March 31, 2013, there was unrecognized compensation cost of $5 million related to options, $44 million related to restricted stock and nil related to restricted stock units, which is expected to be recognized over a weighted average period of 0.6 years for options, 1.8 years for restricted stock and 0.1 years for restricted stock units. We issue new shares from our share reserves set aside for the Calpine Equity Incentive Plans and employment inducement options when stock options are exercised and for other share-based awards.

A summary of all of our non-qualified stock option activity for the Calpine Equity Incentive Plans for the three months ended March 31, 2013, is as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding — December 31, 2012	17,862,501	$17.30	4.0	$42
Granted	11,299	$18.34		
Exercised	580,975	$15.75		
Forfeited	—	$—		
Expired	12,400	$17.77		
Outstanding — March 31, 2013	17,280,425	$17.36	3.7	$69
Exercisable — March 31, 2013	10,344,468	$18.82	3.5	$29
Vested and expected to vest – March 31, 2013	17,051,325	$17.39	3.6	$68

The total intrinsic value of our employee stock options exercised was $2 million and nil for the three months ended March 31, 2013 and 2012, respectively. The total cash proceeds received from our employee stock options exercised was $9 million and nil for the three months ended March 31, 2013 and 2012, respectively.

The fair value of options granted during the three months ended March 31, 2013 and 2012, was determined on the grant date using the Black-Scholes option-pricing model. Certain assumptions were used in order to estimate fair value for options as noted in the following table:

	2013		2012	
Expected term (in years)(1)	6.5		6.5	
Risk-free interest rate(2)	1.4	%	1.6	%
Expected volatility(3)	26	%	30	%
Dividend yield(4)	—		—	
Weighted average grant-date fair value (per option)	$5.31		$5.18	

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(1) Expected term calculated using the simplified method prescribed by the SEC due to the lack of sufficient historical exercise data to provide a reasonable basis to estimate the expected term.

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

(3) Volatility calculated using the implied volatility of our exchange traded stock options.

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(4) We have never paid cash dividends on our common stock, and it is not anticipated that any cash dividends will be paid on our common stock in the near future.

No restricted stock or restricted stock units have been granted other than under the Calpine Equity Incentive Plans. A summary of our restricted stock and restricted stock unit activity for the Calpine Equity Incentive Plans for the three months ended March 31, 2013, is as follows:

	Number of Restricted Stock Awards	Weighted Average Grant-Date Fair Value
Nonvested — December 31, 2012	4,134,037	$14.33
Granted	1,719,783	$18.40
Forfeited	26,941	$15.07
Vested	1,075,603	$11.54
Nonvested — March 31, 2013	4,751,276	$16.44

The total fair value of our restricted stock and restricted stock units that vested during the three months ended March 31, 2013 and 2012, was approximately $20 million and $1 million, respectively.

Liability Classified Share-Based Awards

In February 2013, our Board of Directors approved the aggregate award of 449,798 performance share units to certain senior management employees. These performance share units will be settled in cash with payouts based on the relative performance of Calpine's TSR over the three-year performance period of January 1, 2013 through December 31, 2015 compared with the TSR performance of the S&P 500 companies over the same period. The performance share units vest on the last day of the performance period and will be settled in cash; thus, these awards are liability classified and are measured at fair value using a Monte Carlo simulation model at each reporting date until settlement. The performance share units had a grant date fair value of $21.25 and stock-based compensation expense recognized related to these awards during the three months ended March 31, 2013 was not significant.

10. Commitments and Contingencies

Litigation

We are party to various litigation matters, including regulatory and administrative proceedings arising out of the normal course of business. At the present time, we do not expect that the outcome of any of these proceedings will have a material adverse effect on our financial condition, results of operations or cash flows.

On a quarterly basis, we review our litigation activities and determine if an unfavorable outcome to us is considered "remote," "reasonably possible" or "probable" as defined by U.S. GAAP. Where we determine an unfavorable outcome is probable and is reasonably estimable, we accrue for potential litigation losses. The liability we may ultimately incur with respect to such litigation matters, in the event of a negative outcome, may be in excess of amounts currently accrued, if any; however, we do not expect that the reasonably possible outcome of these litigation matters would, individually or in the aggregate, have a material adverse effect on our financial condition, results of operations or cash flows. Where we determine an unfavorable outcome is not probable or reasonably estimable, we do not accrue for any potential litigation loss. The ultimate outcome of these litigation matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome be reasonably estimated. As a result, we give no assurance that such litigation matters would, individually or in the aggregate, not have a material adverse effect on our financial condition, results of operations or cash flows.

Environmental Matters

We are subject to complex and stringent environmental laws and regulations related to the operation of our power plants. On occasion, we may incur environmental fees, penalties and fines associated with the operation of our power plants. At the present time, we do not 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.

11. Segment Information

We assess our business on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and other factors impacting supply and demand. At March 31, 2013, our reportable segments were West (including geothermal), Texas, North (including Canada) and Southeast. We continue to evaluate the optimal manner in which we assess our performance including our segments and future changes may result.

Commodity Margin is a key operational measure reviewed by our chief operating decision maker to assess the performance of our segments. The tables below show our financial data for our segments for the periods indicated (in millions).

	Three Months Ended March 31, 2013					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$383	$407	$306	$145	$ —	$1,241
Intersegment revenues	1	7	7	33	(48)	—
Total operating revenues	$384	$414	$313	$178	$ (48)	$1,241
Commodity Margin	$202	$76	$142	$41	$ —	$461
Add: Unrealized mark-to-market commodity activity, net and other[(1)]	(37)	(11)	7	7	(7)	(41)
Less:						
Plant operating expense	93	68	44	30	(8)	227
Depreciation and amortization expense	51	43	33	19	—	146
Sales, general and other administrative expense	4	17	6	5	1	33
Other operating expenses	9	1	7	2	(1)	18
(Income) from unconsolidated investments in power plants	—	—	(8)	—	—	(8)
Income (loss) from operations	8	(64)	67	(8)	1	4
Interest expense, net of interest income						174
Other (income) expense, net						5
Loss before income taxes						$(175)

	Three Months Ended March 31, 2012					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$416	$356	$298	$166	$ —	$1,236
Intersegment revenues	4	20	3	22	(49)	—
Total operating revenues	$420	$376	$301	$188	$ (49)	$1,236
Commodity Margin(2)(3)	$208	$109	$144	$56	$ —	$517
Add: Unrealized mark-to-market commodity activity, net and other(1)	36	34	12	10	(8)	84
Less:						
Plant operating expense	81	68	45	33	(6)	221
Depreciation and amortization expense	50	35	33	23	(1)	140
Sales, general and other administrative expense	8	11	6	8	—	33
Other operating expenses	11	2	9	1	(2)	21
(Income) from unconsolidated investments in power plants	—	—	(9)	—	—	(9)
Income from operations	94	27	72	1	1	195
Interest expense, net of interest income						182
Loss on interest rate derivatives						14
Debt extinguishment costs and other (income) expense, net						14
Loss before income taxes						$(15)

(1) Includes $(16) million and $(8) million of lease levelization and $4 million and $4 million of amortization expense for the three months ended March 31, 2013 and 2012, respectively.

(2) Our North segment includes Commodity Margin of $8 million for the three months ended March 31, 2012 related to Riverside Energy Center, LLC, which was sold in December 2012.

(3) Our Southeast segment includes Commodity Margin of $11 million for the three months ended March 31, 2012 related to Broad River, which was sold in December 2012.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations
Forward-Looking Information
This Management’s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our accompanying Consolidated Condensed Financial Statements and related notes. See the cautionary statement regarding forward-looking statements on page viii of this Report for a description of important factors that could cause actual results to differ from expected results.
Introduction and Overview
We are one of the largest wholesale power generators in the U.S. measured by power produced. We own and operate primarily natural gas-fired and geothermal power plants in North America and have a significant presence in major competitive wholesale power markets in California, Texas and the Mid-Atlantic region of the U.S. We sell wholesale power, steam, capacity, renewable energy credits and ancillary services to our customers, which include utilities, independent electric system operators, industrial and agricultural companies, retail power providers, municipalities, power marketers and others. As a result of our investment in cleaner power generation, we have become a recognized leader in developing, constructing, owning and operating an environmentally responsible portfolio of flexible and reliable power plants. In order to manage our various physical assets and contractual obligations, we continue to execute commodity agreements within the guidelines of our Risk Management Policy. We purchase primarily natural gas and some fuel oil as fuel for our power plants and engage in related natural gas transportation and storage transactions. We purchase electric transmission rights to deliver power to our customers. We also enter into natural gas and power physical and financial contracts to hedge certain business risks and optimize our portfolio of power plants. Our goal is to be recognized as the premier power generation company in the U.S. as measured by our employees, customers, regulators, shareholders and the communities in which our facilities are located. We seek to achieve sustainable growth through financially disciplined power plant development, construction, acquisition, operation and ownership. We continue to pursue opportunities to improve our fleet performance and reduce operating costs.
We continue to make significant progress to deliver financially disciplined growth, to enhance shareholder value through our capital allocation (including share repurchases), and to set the foundation for continued growth and success with the following achievements during 2013:

- Our entire fleet achieved an exceptionally low forced outage factor of 1.5% and an impressive starting reliability of 98% during the first quarter of 2013.
- We commenced construction on the first phase of Garrison Energy Center during the second quarter of 2013 and expect COD by the second quarter of 2015.
- In February 2013, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock, bringing the cumulative authorization total to $1.0 billion. As of the filing of this Report, we have repurchased a total of 3,034,797 shares of our outstanding common stock under the additional $400 million authorization for approximately $58 million at an average price paid of $18.97 per share.
- In February 2013, we repriced our First Lien Term Loans by lowering the LIBOR floor by 0.25% to 1.0% and lowering the LIBOR margin by 0.25% to 3.0%. We estimate that this repricing will lower our annual interest expense by approximately $12 million.
- On April 22, 2013, we announced that CCFC, our indirect, wholly-owned subsidiary, is pursuing a potential debt refinancing whereby CCFC will enter into a new senior secured term loan and the funds will be used to repay the CCFC Notes. The timing, size and terms of any potential refinancing and the use of proceeds thereof are subject to market and other conditions and we make no assurance that such actions will take place.

We assess our business on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and other factors impacting supply and demand. Our reportable segments are West (including geothermal), Texas, North (including Canada) and Southeast.
Our portfolio, including partnership interests, consists of 93 power plants, including 5 under construction (2 new power plants and 3 expansions of existing power plants), located throughout 20 states in the U.S. and in Canada, with an aggregate current generation capacity of 27,321 MW and 1,472 MW under construction. Our fleet, including

projects under construction, consists of 75 combustion turbine-based plants, 2 fossil steam-based plants, 15 geothermal turbine-based plants and 1 photovoltaic solar plant. Our segments have an aggregate generation capacity of 6,751 MW with an additional 773 MW under construction in the West, 8,014 MW with an additional 390 MW under construction in Texas, 7,320 MW with an additional 309 MW under construction in the North and 5,236 MW in the Southeast. Our Geysers Assets are included in our West segment.

Legislative and Regulatory Update

We are subject to complex and stringent energy, environmental and other laws and regulations at the federal, state and local levels as well as rules within the RTO and ISO markets in which we participate. Federal and state legislative and regulatory actions, including those by ISO/RTOs, continue to change how our business is regulated. We are actively participating in these debates at the federal, regional, state and ISO/RTO levels. Significant updates are discussed below. For a further discussion of the environmental and other governmental regulations that affect us, see "— Governmental and Regulatory Matters" in Part I, Item 1 of our 2012 Form 10-K.

Mercury and Air Toxics Standards

On December 21, 2011, the EPA issued the National Emission Standards for Hazardous Air Pollutants ("NESHAP") from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, otherwise known as the Mercury and Air Toxics Standards ("MATS"). MATS will reduce emissions of all hazardous air pollutants emitted by coal- and oil-fired electric generating units, including mercury (Hg), arsenic (As), chromium (Cr), nickel (Ni) and acid gases.

The EPA estimates that there are approximately 1,400 units affected by MATS, consisting of approximately 1,100 existing coal-fired units and 300 oil-fired units at approximately 600 power plants. The CAA provides existing units three years from the effective date of MATS to achieve compliance. As a result, existing coal-fired units without emissions controls will need to retire or install controls on acid gases, mercury and particulate matter emissions by April 16, 2015. State enforcement authorities also have discretion under the CAA to provide an additional year for technology installation to comply with MATS. Further, the EPA issued a policy memorandum which indicates that the EPA may provide, in limited circumstances due to delays in the installation of controls, an additional year extension for MATS compliance where necessary to maintain electric system reliability. Accordingly, although the EPA's analysis indicates that it should take no longer than three years for most existing units to comply, they may have up to five years, or until April 16, 2017, to install controls and comply with MATS.

We are not directly affected by MATS because it does not apply to natural gas-fired units, peaking units or units that use fuel oil as a backup fuel. We believe that the emission standards are sufficiently stringent to force existing coal-fired units without emissions controls to retire or to install the necessary controls by April 16, 2015 (unless an extension is granted), which could benefit our competitive position.

A total of 30 petitions for review challenging MATS were filed in the U.S. Court of Appeals for the D.C. Circuit ("D.C. Circuit") and subsequently consolidated under the case White Stallion Energy Center v. EPA. The case is being litigated on two separate briefing schedules: one addressing the "new unit" standards; and one addressing the balance of MATS. We, along with other electric generators, have intervened in this litigation in support of the EPA.

With respect to the existing unit MATS, industry petitioners' primary focus is in challenging the EPA's threshold determinations that emissions of Hazardous Air Pollutants from coal- and oil-fired electric generating units pose hazards to public health and the environment and that it is appropriate and necessary for the EPA to regulate such emissions. The industry petitioners also raise several other arguments, including that the EPA based the existing-source mercury standard, which per the statute must be based on the top 12% of sources for which the EPA has information, on data that were too randomly selected or were "cherry-picked" by the EPA. Briefing of the case is complete and the case is awaiting oral argument.

With regard to the new unit standards, the case was stayed on September 12, 2012 per the EPA's motion to hold the case in abeyance pending the EPA's reconsideration of the new unit MATS (to resolve issues related to measurement of mercury emissions and the data underlying particulate matter and hydrogen chloride emissions standards). The EPA finalized changes to the new unit standards on March 28, 2013. The D.C. Circuit severed and held in abeyance an additional portion of the consolidated challenges to the MATS Rule relating to issues of work practice standards applicable during periods of startup and shutdown on April 3, 2013.

Cross-State Air Pollution Rule

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR") which would require a total of 28 states, primarily in the eastern U.S., to reduce annual SO2 emissions, annual NOx emissions and/or ozone season NOx emissions to assist in attaining three NAAQS: the 1997 annual PM2.5 NAAQS, the 1997 8-hour ozone NAAQS, and the 2006 24-hour PM2.5 NAAQS.

CSAPR established an unlimited intrastate and limited interstate trading program with allowances allocated to sources based on historic heat input but capped at maximum annual emissions from 2003 to 2010. At current capacity factors, Calpine would have been allocated sufficient allowances; thus, CSAPR was not expected to have a negative impact on our operations. We expected the overall impact of CSAPR to be positive for Calpine because the significant emissions reduction requirements would require coal-fired electric generating units to either purchase allowances, switch to more expensive fuels, install air pollution controls, or reduce or discontinue operations, thereby incenting the increased utilization of existing, and development of new, natural gas-fired power plants.

A number of power generation companies, states and other groups filed petitions for review in the D.C. Circuit challenging CSAPR, and these cases were consolidated under EME Homer City Generation v. EPA. Calpine, other power generation companies, states, cities, and public health groups were granted intervenor status on behalf of respondent EPA.

On August 21, 2012, the D.C. Circuit vacated CSAPR. The D.C. Circuit ordered the EPA to continue administering CAIR, which the EPA has been implementing since the D.C. Circuit stayed CSAPR in December 2011 and which CSAPR was designed to replace due to the flaws in CAIR identified by the D.C. Circuit in North Carolina v. EPA. The EPA petitioned for en banc rehearing (i.e., by all active judges on the D.C. Circuit) on October 5, 2012. Intervenors supporting the EPA also submitted three petitions for en banc rehearing upon similar grounds, including one submitted by a coalition of environmental and public health organizations, one by a group of cities and states (including the states of North Carolina, Connecticut, Delaware, Illinois, Maryland, Massachusetts, New York, Rhode Island and Vermont) and one jointly filed by Calpine and Exelon Corporation. On January 24, 2013, the D.C. Circuit denied en banc rehearing in this case.

On March 29, 2013, the EPA and environmental groups filed two separate petitions for a writ of certiorari for the U.S. Supreme Court to review the D.C. Circuit panel decision in EME Homer City. On April 18, 2013, Calpine and another party filed a brief with the U.S. Supreme Court in support of the petitions filed by the EPA and environmental groups. Assuming the D.C. Circuit decision is not reviewed by the U.S. Supreme Court, or not reversed in the event a petition for writ of certiorari is granted, the EPA must continue to implement CAIR while it creates a replacement for CSAPR.

GHG Emissions

On April 2, 2007, the U.S. Supreme Court in Massachusetts v. EPA ruled that the EPA has the authority to regulate GHG emissions under the CAA. In response to Massachusetts, the EPA issued an endangerment finding for GHGs on December 7, 2009, determining that concentrations of six GHGs endanger the public health and welfare. Further, pursuant to the CAA's requirement that the EPA establish motor-vehicle emission standards for "any air pollutant . . . which may reasonably be anticipated to endanger public health or welfare", the EPA promulgated the so-called "Tailpipe Rule", which set GHG emission standards for cars and light trucks.

Under the EPA's longstanding interpretation of the CAA, the Tailpipe Rule automatically triggered regulation of stationary sources of GHG emissions under the Prevention of Significant Deterioration ("PSD") program (which requires state-issued construction permits for stationary sources that have the potential to emit over 100 or 250 tons per year ("tpy"), the applicable threshold depending on the type of source, of "any air pollutant") and Title V (which requires state-issued operating permits for stationary sources that have the potential to emit at least 100 tpy of "any air pollutant"). Accordingly, the EPA issued two rules phasing in stationary source GHG regulation. In the Timing Rule, the EPA delayed when major stationary sources of GHGs would otherwise be subject to PSD and Title V permitting, concluding that these requirements would commence on January 2, 2011, the date on which the Tailpipe Rule became effective. In the Tailoring Rule, the EPA departed from the CAA's 100/250 tpy emissions thresholds and provided that only the largest sources, those exceeding 75,000 or 100,000 tpy carbon dioxide equivalent ("CO2e"), depending on the program and project, would initially be subject to GHG permitting.

Under Step 1 of the Tailoring Rule (beginning in January 2011), new or modified sources already required to obtain a PSD permit due to their emissions of conventional regulated pollutants must satisfy best available control technology ("BACT") requirements for GHGs if they emit or have the potential to emit at least 75,000 tpy CO2e. Under Step 2 of the Tailoring Rule (beginning in July 2011), new sources that emit or have the potential to emit at least 100,000 tpy CO2e and existing sources that emit at that level and that undertake modifications that increase emissions by at least 75,000 tpy CO2e must obtain a PSD permit and satisfy BACT requirements for GHGs, regardless of their emissions of any conventional pollutants. Step 3 of the Tailoring Rule was finalized in July 2012 and maintained the GHG PSD and Title V permitting thresholds specified under Step 2.

The EPA has issued guidance to permitting authorities on the implementation of GHG BACT that focuses on energy efficiency. We believe that the impact of the Tailoring Rule will be neutral to us because we expect that our efficient power plants would be found to meet BACT for GHGs if required to undergo PSD review. Calpine's Russell City Energy Center, a 619 MW combined-cycle power plant (Calpine's 75% net interest is 464 MW) being constructed in Hayward, California, voluntarily accepted GHG BACT limits in its PSD permit before such limits were required by law.

More than sixty petitions for review of these EPA rules were filed by industry and states, which were subsequently consolidated in the D.C. Circuit case Coalition for Responsible Regulation v. EPA. On June 26, 2012, the D.C. Circuit, in an unsigned per curiam opinion, upheld all of the challenged GHG regulations. Specifically, the D.C. Circuit denied the petitions relating to the Endangerment Finding and the Tailpipe Rule on the merits, while dismissing the petitions for review of the Timing Rule and the Tailoring Rule on constitutional standing grounds.

On August 10, 2012, industry groups requested rehearing en banc of the D.C. Circuit's decision in Coalition for Responsible Regulation. The D.C. Circuit denied en banc review on December 20, 2012.

In light of the rehearing petition, on October 9, 2012, the D.C. Circuit decided to hold in abeyance a related case regarding Step 3 of the EPA's Tailoring Rule (American Petroleum Institute v. EPA). While the case was removed from abeyance on January 28, 2013, on February 13, 2013, petitioners and the EPA requested that this case again be held in abeyance until the later of: (i) the expiration of the period for filing petitions for a writ of certiorari in Coalition for Responsible Regulation, (ii) the date on which all such petitions have been denied (in the absence of a grant of any such petition), or (iii) if any such petition is granted, completion of proceedings on any such petition in the U.S. Supreme Court. The D.C. Circuit has not ruled on this abeyance request yet.

On March 20, 2013, three entities timely filed petitions for a writ of certiorari to the U.S. Supreme Court to review Coalition for Responsible Regulation. The Supreme Court also granted other parties to the case an extension in which to file additional petitions for a writ of certiorari. On April 18 and 19, 2013, several other parties filed petitions for a writ of certiorari to the U.S. Supreme Court, including a petition filed by several states that ask the U.S. Supreme Court to reconsider or overrule its 2007 decision in Massachusetts v. EPA.

In a related GHG regulatory development, the EPA published a proposed New Source Performance Standard ("NSPS") for GHG emissions from new electric generating units on April 13, 2012. The proposed rule would establish an output-based CO2 emissions standard of 1,000 lbs/MWh gross for new fossil fuel-fired generating units, which include boilers, integrated gasification combined-cycle units and stationary combined-cycle turbine units greater than 25 MW. The emissions standard is based on the performance of natural gas combined-cycle technology. The proposed NSPS would not apply to simple-cycle plants, plants that burn biomass, existing sources, sources being modified, or so-called "transitional sources" (i.e., coal-fired plants that received PSD permits by the publication date of the proposed rule (April 13, 2012) and commence construction within 12 months of the publication date of the proposal).

The proposed NSPS would have no impact on Calpine's fleet or development plans. According to the EPA, the proposed NSPS would result in no notable compliance costs because, even in its absence, the electric sector would choose to build natural gas-fired electric generating units that already comply with the proposed standard.

The comment period on the proposed NSPS rule closed on June 25, 2012. Although the proposal is not yet final, several developers of permitted coal-fired power plants that could not meet the proposed NSPS without installation of carbon capture and storage technology filed suit in the D.C. Circuit, challenging the EPA's proposal. On December 13, 2012, the D.C. Circuit dismissed the industry challenge to the proposed NSPS because the proposed rule is not "final agency action" subject to judicial review.

On April 12, 2013, the EPA announced that it would delay finalizing the GHG NSPS for new power plants, which the CAA required be finalized by April 13, 2013 (one year from the date of publication of the proposed rule). On April 15, 2013, a group of environmental organizations notified the EPA of their intention to sue the EPA for its failure to finalize the new power plant standards and issue GHG emission guidelines for existing plants. On April 17, 2013, ten states, the District of Columbia and the City of New York notified the EPA of their intention to sue the EPA for these same alleged failures in federal court. It is unclear when the EPA will finalize the GHG NSPS. Finalizing the rule is a predicate for the EPA's promulgation of a GHG NSPS standard for existing power plants.

Section 185 Fees on Permissible Emissions

During the first quarter of 2013, we reversed our estimate for retroactive Section 185 fees of $11 million as we determined that the likelihood of a payment obligation is not probable based on the actions of the TCEQ and New York regulatory officials in regard to retroactive collection. The EPA has not taken a firm position on retroactive collection of Section185 fees. See our 2012 Form 10-K for a further description of fees related to Section 185 of the CAA.

Demand Response Resources

On March 29, 2013, Calpine and PSEG Power LLC filed a petition for reconsideration in opposition to the final rule with the EPA regarding the NESHAP for Reciprocal Internal Combustion Engines. The final rule creates an exemption from otherwise applicable NESHAP air emission requirements for engines used for “emergency demand response” thus allowing the increased use of uncontrolled, behind-the-meter diesel engines for the generation of electricity resulting in an increase in ozone

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during the peak ozone season. Additionally, on April 1, 2013, Calpine, First Energy Solutions Corporation and PSEG Power LLC filed a petition for review of the final rule with the D.C. Circuit. Both petitions are pending at this time.

Clean Water Act and Cooling Water Intake Rule

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

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The EPA finalized the Phase I Rule in 2001, which applies to new facilities. The EPA initially promulgated the Phase II Rule, applying to large existing facilities, in 2004. Finally, the EPA finalized the Phase III Rule in 2006, which covers certain existing facilities and new offshore and coastal oil and gas extraction facilities.

However, in response to the Second Circuit Court of Appeals' decision in Riverkeeper, Inc., v. EPA, the EPA suspended the Phase II Rule. In November 2010, the EPA signed a settlement agreement with Riverkeeper, Inc. requiring the EPA to set technology standards for cooling water intake structures for existing facilities. The EPA is now required to finalize an updated rule for existing facility water intake structures by June 27, 2013. Calpine continues to participate in the rulemaking process; however, while the Section 316(b) rule will likely affect our competitors, we do not expect these rules to have a material impact on our operations because only two peaking power plants we own employ once-through cooling systems, one of which (Deepwater Energy Center) is scheduled to retire in 2015.

Additionally, the EPA informally released proposed revisions to effluent limitation guidelines for the steam electric point source category on April 20, 2013. The EPA is bound by a court ordered consent decree to issue a final rule by May 22, 2014. This rule is not expected to have a material impact on our operations.

In California, the EPA delegates the implementation of Section 316(b) to the California State Water Resources Control Board ("SWRCB"). SWRCB has promulgated its own once-through cooling policy that establishes a schedule for once-through cooling units to install closed-cycle wet cooling (i.e., cooling towers) or reduce entrainment and impingement to comparable levels as would be achieved with a cooling tower, or be retired. The compliance dates for approximately 12,000 MW of once-through cooling capacity in California occur between 2012 and 2020. We do not anticipate that the SWRCB's policy will have a negative impact on our operations, as none of our power plants in California utilize once-through cooling systems.

California: GHG — Cap-and-Trade Regulation

California's AB 32 requires the State to reduce statewide GHG emissions to 1990 levels by 2020. To meet this benchmark, the CARB has promulgated a number of regulations, including the Cap-and-trade regulation. In late 2011, the CARB finalized its Cap-and-trade regulation and mandatory reporting regulation, which took effect on January 1, 2012. These regulations were further amended by the CARB in 2012.

Under the Cap-and-trade regulation, the first compliance period for covered entities like Calpine began on January 1, 2013 and runs through the end of 2014. The second and third compliance periods cover 2015 through 2017 and 2018 through 2020, respectively. Covered entities must hold and surrender compliance instruments, which include allowances and offsets, in an amount equivalent to their emissions from sources of GHG located in California and from power imported into California.

The first auction of GHG allowances was held on November 14, 2012 and included the sale of 2013 and 2015 vintage allowances. The 2013 vintage allowances cleared just above the $10 auction reserve price, while the 2015 vintage allowances cleared at the $10 reserve price, with only 14% of those available sold. The second auction was held on February 19, 2013. All vintage 2013 allowances available cleared at $13.62. The vintage 2016 allowances cleared at the auction reserve price of $10.71; with only 46% of those available sold. Quarterly auctions will be held every year from 2013 to 2020 with the next auction scheduled for May 16, 2013. The GHG emissions market is currently functioning and the cost of allowances is reflected in market pricing.

Currently, there are three pending lawsuits challenging the Cap-and-trade regulation. On March 28, 2012, two environmental organizations filed a lawsuit in San Francisco Superior Court seeking to invalidate the four protocols published by CARB for issuing offsets. On January 25, 2013, the court rejected the petitioners' claims, holding that the CARB's development of the protocols was consistent with AB 32. The petitioners have until May 26, 2013 to appeal the decision in the California Court of Appeals.

Additionally, on November 13, 2012, the California Chamber of Commerce filed a complaint in the Sacramento Superior Court challenging the CARB's authority to auction allowances under AB 32 and the California Constitution. The Sacramento Superior Court is scheduled to hold a hearing on the merits in that case on August 28, 2013.

Most recently, on April 16, 2013, Pacific Legal Foundation filed a lawsuit in the Sacramento Superior Court on behalf of several businesses, trade associations and individuals claiming that the Cap-and-trade regulation constitutes an impermissible tax under the California Constitution and is not authorized by AB 32.

We cannot predict the ultimate success of any of these lawsuits nor can we predict whether there will be any additional legal challenges filed against the regulation or what the associated impacts of any such litigation would be.

In September 2012, the CARB Board directed its staff, by mid-2013, to propose amendments to the Cap-and-trade regulation that would, among other things, increase the auction purchase limit for covered entities and provide allowances to covered entities that have long-term contracts that do not allow the costs of compliance to be passed through to their customers. The CARB has recently indicated that it will propose draft regulatory amendments by June 2013 for CARB Board approval in October 2013.

On January 8, 2013, the CARB published a notice for a 15-day rulemaking concerning linkage of California's and Quebec's Cap-and-trade programs ("Linkage Notice"). The Linkage Notice provides background for CARB's request that the California Governor make certain findings under Senate Bill 1018, which are required before California links with any other jurisdiction's Cap-and-trade program. The Governor made these findings in a letter to the CARB dated April 8, 2013, and on April 19, 2013, the CARB's Board approved the amendments to link its program with Quebec's Cap-and-trade program starting January 1, 2014. The first auction is not yet scheduled but will not take place any earlier than the first quarterly auction in 2014. The CARB's economic analysis estimates that linkage between California and Quebec has the potential to increase California's GHG allowance prices by 5% to 15%.

Overall, we support AB 32 and expect the net impact of the Cap-and-trade regulation to be beneficial to Calpine. We also believe we are well positioned to comply with these regulations.

ERCOT Market Structure

The PUCT continues its very deliberative approach of considering design changes aimed at improving the ERCOT market's scarcity pricing signals and long-term resource adequacy. Of the two rulemakings undertaken in April 2012, the project dealing with near term system-wide offer cap ("SWOC") resulted in the offer cap being raised from \$3,000/MWh to \$4,500/MWh and took effect on August 1, 2012. On June 1, 2013, the SWOC will increase from \$4,500/MWh to \$5,000/MWh. Given the potential liquidity impacts of the higher offer cap, ERCOT stakeholders are considering associated market credit and collateralization design changes in an effort to keep pace with the potential increase in the market's risk exposure. With these changes, we expect higher prices when scarcity pricing conditions occur which could have a positive impact on our Commodity Margin.

The PUCT has deferred further consideration of the two separate resource adequacy proposals prepared by The Brattle Group for PUCT consideration: a modified energy-only proposal and the Texas Capacity Market, a centralized forward capacity market mechanism similar to PJM's. In addition, The Brattle Group provided a demand response analysis that shows how much and how quickly price responsive demand can penetrate the ERCOT market. The PUCT has not voted on either proposal or established a timetable for further consideration of the proposals or whether to adopt a Reserve margin requirement versus continuing with the current Reserve margin target. The PUCT may consider a major change to ERCOT's resource adequacy mechanism in the second half of 2013, but the timing remains uncertain. We continue to support the development of a centralized forward capacity market, which, depending on implementation, we view as superior to any energy-only mechanism, to ensure ERCOT meets its reliability objective under any market conditions. As these proceedings are ongoing, we cannot predict what the ultimate impact may be nor the impact on our financial condition, results of operations or cash flows.

The PUCT continues to consider other proposals to improve proper wholesale price formation. At the request of the PUCT, ERCOT has developed a proposal for an operating reserves demand curve for PUCT and ERCOT stakeholder consideration. The key feature of the proposal is a pricing methodology based on the Value of Lost Load ("VOLL") and Loss of Load Probability. The result of this calculation is a value that is dependent on the amount of available operating reserves, but added to the system-wide clearing price, without regard to whether the system is in scarcity conditions. It is not likely any proposal being considered by the PUCT would be implemented until summer 2014. We support the evaluation of this concept, but unlike a centralized forward capacity market, we do not view this concept as a solution for long-term resource adequacy in ERCOT. We cannot predict, at this time, all of the details of a final proposal or the ultimate impact on our financial condition, results of operations or cash flows.

ERCOT's planning function has undertaken two very significant study efforts, both of which may have important implications for the region's resource adequacy metrics and ultimately the value of power in the ERCOT market. A Loss of Load Expectation study has been conducted by a vendor and the final draft was delivered to stakeholders on January 18, 2013. The study will show for one occurrence of the loss of firm load in a 10-year period what annual planning Reserve margin percentage is required for resource planning. The study shows that a planning Reserve margin is required that is materially greater than the currently targeted 13.75% if the experienced weather and loading patterns of the summer of 2011 are included in the study's model runs. Initial stakeholder reaction was to endorse the study's methodology as well as to include the weather impacts of summer 2011. The range of possible annual planning reserve values for study year 2014 supported by the study that the ERCOT Board of Directors might consider is from 15.8% to 18.9%. The study results will be further vetted with stakeholders and it is expected that the ERCOT Board of Directors could take action in changing the annual planning Reserve margin at its May 2013 meeting. The second study effort will estimate the VOLL. That study is expected to be completed in mid-2013 and should provide meaningful estimates for the value of firm customer load in the various load categories when firm load shedding is necessary in emergency conditions. The current SWOC is $4,500/MWh and will increase to $5,000/MWh on June 1, 2013, $7,000/MWh on June 1, 2014 and $9,000/MWh on June 1, 2015, and the VOLL study may shed some light on whether the SWOC is high enough to approximate the VOLL.

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, including the PUCT. The Sunset Review Process works by setting a date on which an agency will be abolished unless legislation is passed to continue its functions. While significant changes were proposed by the Sunset Advisory Commission for the PUCT, the legislation did not become law. Therefore, the Sunset Advisory Commission has undertaken another review of the PUCT and any resulting PUCT Sunset legislation will be considered in the 2013 legislative session, which is scheduled to conclude on May 27, 2013. We cannot predict which changes, if any, will be placed into legislation and ultimately reach final passage. We will continue to participate in the legislative process where we anticipate any potential impact on our business.

ERCOT Voluntary Mitigation Plan

In March 2013, the PUCT approved our application for a Voluntary Mitigation Plan effective March 28, 2013, establishing a safe harbor for energy offers by us for the sale of electricity from our power plants into the ERCOT real-time market if made in a manner consistent with the plan.

PJM Capacity Market

Certain states in the PJM market region, particularly New Jersey and Maryland, have taken actions that could impact the PJM capacity market. In New Jersey, legislation enacted in 2011 required the New Jersey Board of Public Utilities ("BPU") to issue a request for proposals ("RFP") for new generation. As a result of the RFP, the BPU directed New Jersey's four public utilities to enter into standard offer capacity agreements with the winning generators for new capacity to be built in New Jersey. Several entities have appealed the BPU's order directing the public utilities to enter into long-term contracts with those generators. The appeal process is continuing. Also, on February 9, 2011, we joined a group of generators and utilities in filing a complaint in federal district court challenging the constitutionality of the New Jersey legislation. The case is currently in trial and is expected to conclude in May 2013.

On September 29, 2011, the Maryland Public Service Commission ("MPSC") issued a "Notice of Approval of Request for Proposals for New Generation to be Issued by Maryland Electric Distribution Companies" (the "Notice"). The Notice required the state's IOUs to issue RFPs for up to 1,500 MW of capacity. The Notice specifies that proposals must be for new natural gas-fired capacity capable of delivery into the PJM Southwest Mid-Atlantic Area Council ("SWMAAC") delivery area. On April 12, 2012, the MPSC issued a further order in this proceeding directing certain Maryland IOUs located in the SWMAAC area to enter into a contract for differences with CPV Maryland, LLC ("CPV"), a generation developer that is currently developing a 661 MW natural gas-fired, combined-cycle generation plant in SWMAAC. The facility's scheduled COD is June 1, 2015. In May 2012, we filed with the Circuit Court of Baltimore County, Maryland a Petition for Review of the MPSC's order, asking the court to review the order and declare it invalid. Several other parties filed similar appeals. The appeals have been consolidated, but the case was suspended pending resolution of certain contract terms between the IOUs and CPV. On April 16, 2013, the MPSC issued a further order resolving the outstanding contract terms and directing the IOUs and CPV to negotiate the final terms of the contracts and submit those contracts to the MPSC for approval. Once the contracts are approved by the MPSC, the appeals process should recommence. In a separate action, several generators have filed a complaint in federal district court challenging the constitutionality of the MPSC’s actions. The trial concluded in March 2013. It is possible that the judge will issue a ruling in the proceeding prior to the 2016/2017 PJM Reliability Pricing Model base residual auction, to be held on May 13-17, 2013.

At the FERC level, PJM has taken action to strengthen the Minimum Offer Price Rule (“MOPR”) in its tariff. PJM’s tariff changes are intended to address the negative implications from these state actions. The FERC issued an order in April 2011 approving amendments to PJM's MOPR tariff provisions. The FERC order is currently on appeal before the U.S. Court of Appeals for the Third Circuit. In December 2012, PJM filed further amendments to the MOPR that are intended to make the MOPR process more transparent and objective. On February 5, 2013, the FERC asked PJM to provide additional information about its proposal. While unclear, given the current timing of PJM's response and a subsequent FERC decision, it is still possible for the changes to be in effect for the 2016/2017 PJM Reliability Pricing Model base residual auction.

California RPS

On April 12, 2011, California's Governor signed into law legislation establishing a new and higher RPS. The new law requires implementation of a 33% RPS by 2020, with intermediate targets between 2010 and 2020. The previous RPS legislation required certain retail power providers to generate or procure 20% of the power they sell to retail customers from renewable resources beginning in 2010. The new standard applies to all load-serving entities, including entities such as large municipal utilities that are not subject to CPUC jurisdiction. Under the new law, there are limits on different "buckets" of procurement that can be used to satisfy the RPS. Load-serving entities must satisfy at least a fraction of their compliance obligations with renewable power from resources located in California or delivered into California within the hour. Similarly, the legislation places limits on the use of "firmed and shaped" transactions and unbundled RECs - claims to the renewable aspect of the power produced by a renewable resource that can be traded separately from the underlying power. In general, the ability to use "firmed and shaped" transactions and unbundled RECs becomes more limited over the course of the implementation period. In our role as an energy service provider, we are subject to the RPS requirements and continue to meet our compliance obligations. The increase in solar and wind generation on the state's electrical grid has increased the need for flexible thermal generation which may be beneficial to Calpine but may also have adverse effects on wholesale electricity prices.

QFs and California State Regulation of Power

A recently implemented CPUC settlement changes significant aspects of policy towards California QFs, including our non-renewable QF facilities. The settlement resolves issues related to QFs under existing QF contracts and establishes new energy pricing options for QFs under QF contracts, including the option to shed QF host and efficiency obligations and become dispatchable, and specifies mechanisms for the California IOUs to procure both existing combined heat and power ("CHP") that is not otherwise under contract and new CHP. Pursuant to the QF Settlement, we have converted two of our former QFs to dispatchable non-QF units, and we offered some of our resources into the IOUs' recent CHP solicitations. The IOUs selected our CHP offers for our Los Medanos Energy Center and Gilroy Cogeneration Plant and filed the contracts with the CPUC for approval. However, the contracts are being challenged by certain parties and are now being held by the CPUC. We cannot predict at this time how the CPUC will rule or whether it will order modifications to the contracts.

California Market Design

The CPUC and CAISO continue to evaluate long-term capacity procurement policies and products for the California power market. With the expectation of significant increases in renewables, both agencies are evaluating the need for generation flexibility attributes such as dispatchability, ramping and load following. In addition, both agencies may consider forward procurement mechanisms or obligations. In this light, the CAISO filed a request at the FERC for a backstop mechanism on December 12, 2012, to address reliability issues associated with renewable integration and allow the CAISO to look forward five years and compensate generation units that are needed for capacity or generation attributes, but would otherwise retire. In January 2013, we objected to the CAISO filing, raising concerns with the CAISO's approach and suggesting that a forward procurement obligation and central capacity clearing mechanism would be superior to the CAISO's proposal. On March 29, 2013, FERC rejected, in its entirety, the CAISO filing and ordered a technical conference to collectively pursue solutions to the reliability challenges presented in this proceeding. Alternatively, FERC stated their belief that the most effective course of action would be for the CAISO and its stakeholders to focus on the development of a durable, market-based mechanism to provide incentives to ensure that the reliability needs are met. The technical conference will be scheduled within 120 days of the FERC order.

Southwest Power Pool ("SPP")

SPP currently manages an energy-only location based real-time wholesale energy market. This market provides both nominal load-following and transmission constraint relief. In October 2012, the FERC approved tariff changes to enact SPP’s proposed “Day 2” wholesale energy markets. SPP, which currently conducts a basic real-time nodal balancing market, will expand its market to a suite of new markets that will include centralized, security-constrained economic unit commitment with both a financially-binding, day-ahead nodal energy market and a physically-binding, real-time nodal energy market, a congestion management market using Transmission Congestion Rights, consolidate existing Balancing Areas and implement ancillary services markets for regulation and reserves. SPP will also have the authority to commit generation for reliability purposes and guarantee cost recovery for such units that are otherwise uneconomic. SPP will also have virtual load and generation markets that will permit hedging and speculation and plans to accommodate demand-side resource market participation. SPP did not propose any type of resource adequacy or capacity market in its new market design. These enhancements are currently scheduled to be implemented simultaneously in March 2014. We believe the market structure is generally beneficial to our Oneta Energy Center which is located in the SPP region.

RESULTS OF OPERATIONS FOR THE THREE MONTHS ENDED MARCH 31, 2013 AND 2012

Set forth below are our results of operations for the three months ended March 31, 2013, as compared to the same period in 2012 (in millions, except for percentages and operating performance metrics). In the comparative tables below, increases in revenue/income or decreases in expense (favorable variances) are shown without brackets while decreases in revenue/income or increases in expense (unfavorable variances) are shown with brackets.

	2013	2012	Change	% Change
Operating revenues:				
Commodity revenue	$1,308	$1,212	$96	8
Unrealized mark-to-market gain (loss)	(71)	22	(93)	#
Other revenue	4	2	2	#
Operating revenues	1,241	1,236	5	—
Operating expenses:				
Fuel and purchased energy expense:				
Commodity expense	835	691	(144)	(21)
Unrealized mark-to-market (gain)	(14)	(56)	(42)	(75)
Fuel and purchased energy expense	821	635	(186)	(29)
Plant operating expense	227	221	(6)	(3)
Depreciation and amortization expense	146	140	(6)	(4)
Sales, general and other administrative expense	33	33	—	—
Other operating expenses	18	21	3	14
Total operating expenses	1,245	1,050	(195)	(19)
(Income) from unconsolidated investments in power plants	(8)	(9)	(1)	(11)
Income from operations	4	195	(191)	(98)
Interest expense	176	185	9	5
Loss on interest rate derivatives	—	14	14	#
Interest (income)	(2)	(3)	(1)	(33)
Debt extinguishment costs	—	12	12	#
Other (income) expense, net	5	2	(3)	#
Loss before income taxes	(175)	(15)	(160)	#
Income tax benefit	(50)	(6)	44	#
Net loss	(125)	(9)	(116)	#
Net income attributable to the noncontrolling interest	—	—	—	—
Net loss attributable to Calpine	$(125)	$(9)	$(116)	#

	2013	2012	Change	% Change
Operating Performance Metrics:				
MWh generated (in thousands)(1)	23,998	28,055	(4,057)	(14)
Average availability	90.1%	90.3%	(0.2)%	—
Average total MW in operation(1)	26,541	27,187	(646)	(2)
Average capacity factor, excluding peakers	47.6%	54.9%	(7.3)%	(13)
Steam Adjusted Heat Rate	7,345	7,272	(73)	(1)

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Variance of 100% or greater

(1) Represents generation and capacity from power plants that we both consolidate and operate and excludes Greenfield LP, Whitby, Freeport Energy Center, 21.5% of Hidalgo Energy Center and 25% of Freestone Energy Center.

We evaluate our Commodity revenue and Commodity expense on a collective basis because the price of power and natural gas tend to move together as the price of power is generally determined by the variable operating cost of the next marginal generator to be dispatched to meet demand. The spread between our Commodity revenue and Commodity expense represents a significant portion of our Commodity Margin. Our financial performance is correlated to how we maximize our Commodity Margin through management of our portfolio of power plants, as well as our hedging and optimization activities. See additional segment discussion in “Commodity Margin and Adjusted EBITDA.”
Commodity revenue, net of Commodity expense, decreased $48 million for the three months ended March 31, 2013, compared to the three months ended March 31, 2012, primarily due to:

- the sale of Broad River and Riverside Energy Center in December 2012 partially offset by the acquisition of Bosque Energy Center in November 2012;
- lower Spark Spreads and generation resulting from a reversal of coal-to-gas switching primarily in our Texas, North and Southeast segments; and
- lower contribution from hedges due to a shift from hedge prices that reflected twelve month strip hedging during the first quarter of 2012 compared to hedge prices that reflected seasonal hedging during the first quarter of 2013 primarily in our Texas segment; partially offset by
- higher revenue from tolling contracts in our West and Southeast segments which became effective in January 2013.

Generation decreased 14% primarily due to a reversal of coal-to-gas switching in our Texas, North and Southeast segments during the first quarter of 2013 compared to the same period in 2012. Our average total MW in operation decreased by 646 MW, or 2%, primarily due to the sale of Broad River and Riverside Energy Center in December 2012 which was partially mitigated by the acquisition of Bosque Energy Center in November 2012 and an increase in capacity resulting from our turbine modernization program.

Unrealized mark-to-market gain/loss from hedging our future generation and fuel needs had an unfavorable variance of $135 million primarily driven by the impact of an overall increase in forward power and natural gas prices on both power and natural gas hedges during the three months ended March 31, 2013, as compared to unrealized gains recorded during the comparable period in 2012 resulting from hedges during a period of falling power and natural gas prices.

Plant operating expense increased by $6 million during the three months ended March 31, 2013 compared to the three months ended March 31, 2012, despite a $16 million decrease in our normal, recurring plant operating expense which includes an $11 million decrease resulting from the reversal of retroactive regulatory fees which we determined the likelihood of a payment obligation is not probable based on the actions of the TCEQ and New York regulatory officials in regard to retroactive collection. Our major maintenance expense resulting from our plant outage schedule increased by $20 million during the first quarter of 2013 compared to the first quarter of 2012.

Depreciation and amortization expense increased during the three months ended March 31, 2013, compared to the three months ended March 31, 2012, primarily resulting from a $6 million increase in depreciation expense due to our acquisition of the Bosque Energy Center in November 2012 and a $4 million increase due to the timing of assets placed into service partially offset by assets that were fully depreciated during the later part of 2012 and in the first quarter of 2013. The increase in depreciation and amortization expense was also partially offset by a decrease of $4 million resulting from lower depreciation associated with the sale of Broad River and Riverside Energy Center in December 2012.

Interest expense decreased by $9 million for the three months ended March 31, 2013, compared to the three months ended March 31, 2012, primarily due to a decrease in our annual effective interest rate on our consolidated debt, excluding the impacts of capitalized interest and unrealized gains (losses) on interest rate swaps, to 7.0% for the three months ended March 31, 2013, from 7.4% for the three months ended March 31, 2012. The issuance of our 2019 First Lien Term Loan in October 2012 allowed us to reduce our overall cost of debt by replacing a portion of our First Lien Notes and variable rate project debt with a corporate level term loan carrying a lower variable interest rate. Also, in February 2013, we repriced our First Lien Term Loans by lowering our interest rate, which decreased our interest expense during the first quarter of 2013. See Note 3 of the Notes to the Consolidated Condensed Financial Statements for further information regarding the repricing of our First Lien Term Loans.

Loss on interest rate derivatives had a favorable change of $14 million for the three months ended March 31, 2013, compared to the three months ended March 31, 2012, resulting from the termination of our legacy interest rate swaps in March 2012 formerly hedging our First Lien Credit Facility. During the three months ended March 31, 2012, we recorded the settlement amount of approximately $156 million reflecting the fair value of the terminated swaps, of which approximately $142 million reflected the realization of losses in prior periods and $14 million was recorded as a component of loss on interest rate derivatives.

Debt extinguishment costs for the three months ended March 31, 2012, consisted of $12 million associated with the purchase of two of the three third party interests in GEC Holdings, LLC in March 2012 that were previously recorded as preferred interests and classified as debt under U.S. GAAP. There were no debt extinguishment costs recorded during the three months ended March 31, 2013.

During the three months ended March 31, 2013, we recorded an income tax benefit of $50 million compared to an income tax benefit of $6 million for the three months ended March 31, 2012. The favorable period-over-period change resulted from a decrease in various state and foreign jurisdiction income taxes of $40 million, of which $19 million was related to an increase in our pre-tax loss during the current period and $21 million was related to the expiration of applicable statutes of limitation related to uncertain tax positions. Also contributing to the favorable period-over-period change was a benefit recognized in federal income taxes of $2 million as a result of an extension of the Alternative Minimum Tax credit and a decrease in income tax expense of $2 million related to the application of intraperiod tax allocation.

COMMODITY MARGIN AND ADJUSTED EBITDA

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

We use Commodity Margin, a non-GAAP financial measure, to assess our performance by our reportable segments. Commodity Margin includes our power and steam revenues, sales of purchased power and physical natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, environmental compliance expense, and realized settlements from our marketing, hedging and optimization activities including natural gas transactions hedging future power sales, but excludes the unrealized portion of our mark-to-market activity and other revenues. We believe that Commodity Margin is a useful tool for assessing the performance of our core operations and is a key operational measure reviewed by our chief operating decision maker. Commodity Margin is not a measure calculated in accordance with U.S. GAAP and should be viewed as a supplement to and not a substitute for our results of operations presented in accordance with U.S. GAAP. Commodity Margin does not intend to represent income from operations, the most comparable U.S. GAAP measure, as an indicator of operating performance and is not necessarily comparable to similarly titled measures reported by other companies. See Note 11 of the Notes to Consolidated Condensed Financial Statements for a reconciliation of Commodity Margin to income (loss) from operations by segment.

Commodity Margin by Segment for the Three Months Ended March 31, 2013 and 2012

The following tables show our Commodity Margin and related operating performance metrics by segment for the three months ended March 31, 2013 and 2012. In the comparative tables below, favorable variances are shown without brackets while unfavorable variances are shown with brackets. The MWh generated by segment below represent generation from power plants that we both consolidate and operate.

West:	2013	2012	Change	% Change
Commodity Margin (in millions)	$202	$208	$(6)	(3)
Commodity Margin per MWh generated	$24.23	$25.36	$(1.13)	(4)
MWh generated (in thousands)	8,337	8,203	134	2
Average availability	88.5 %	93.5 %	(5.0)%	(5)
Average total MW in operation	6,751	6,731	20	—
Average capacity factor, excluding peakers	61.6 %	60.3 %	1.3 %	2
Steam Adjusted Heat Rate	7,287	7,140	(147)	(2)

West — Commodity Margin in our West segment decreased by $6 million, or 3%, for the three months ended March 31, 2013 compared to the same period in 2012, due primarily to lower contribution from hedges which was partially offset by higher revenue from a tolling contract which became effective in January 2013. As reflected in the 2% period-over-period increase in generation, overall market conditions improved during the first quarter of 2013 as the impact of the January 1, 2013 implementation of the AB 32 carbon market positively impacted the open position on our natural gas-fired power plants and our Geysers Assets which are based on absolute power price. Our average availability decreased 5% due to an increase in planned outages scheduled during the three months ended March 31, 2013 compared to the three months ended March 31, 2012.

Texas:	2013	2012	Change	% Change
Commodity Margin (in millions)	$76	$109	$(33)	(30)
Commodity Margin per MWh generated	$9.46	$11.92	$(2.46)	(21)
MWh generated (in thousands)	8,030	9,143	(1,113)	(12)

Average availability	87.2 %	85.7 %	1.5 %	2
Average total MW in operation	7,778	7,003	775	11
Average capacity factor, excluding peakers	47.8 %	59.8 %	(12.0)%	(20)
Steam Adjusted Heat Rate	7,162	7,081	(81)	(1)

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Texas — Commodity Margin in our Texas segment decreased by $33 million, or 30%, for the three months ended March 31, 2013 compared to the same period in 2012, driven by lower Spark Spreads and 12% lower generation resulting from a reversal of coal-to-gas switching during the first quarter of 2013 compared to the same period in 2012. We also experienced lower contribution from hedges primarily due to a shift from hedge prices that reflected twelve month strip hedging during the first quarter of 2012 compared to hedge prices that reflected seasonal hedging during the first quarter of 2013. The overall period-over-period decrease was partially offset by an increase in Commodity Margin resulting from the acquisition of Bosque Energy Center in November 2012 which was also the primary driver of the 775 MW, or 11%, increase in our average total MW in operation for the three months ended March 31, 2013 compared to the same period in 2012. Our average capacity factor decreased 20% resulting from lower generation at our legacy power plants during the three months ended March 31, 2013 compared to the same period in 2012.

North:	2013	2012	Change	% Change
Commodity Margin (in millions)	$142	$144	$(2)	(1)
Commodity Margin per MWh generated	$36.33	$28.88	$7.45	26
MWh generated (in thousands)	3,909	4,987	(1,078)	(22)
Average availability	92.3 %	89.1 %	3.2 %	4
Average total MW in operation	6,776	7,370	(594)	(8)
Average capacity factor, excluding peakers	43.2 %	47.1 %	(3.9)%	(8)
Steam Adjusted Heat Rate	7,911	7,818	(93)	(1)

North — Commodity Margin in our North segment for the three months ended March 31, 2013 was comparable to the same period in 2012. Despite the sale of Riverside Energy Center in December 2012, Commodity Margin was largely unchanged due to higher regulatory capacity revenues during the first quarter of 2013 compared to the first quarter of 2012. Generation decreased 22% which negatively impacted our open position resulting from lower Spark Spreads and a reversal of coal-to-gas switching during the three months ended March 31, 2013 compared to the same period in 2012. However, these negative factors were largely offset by an increase in Commodity Margin contribution from hedges during the first quarter of 2013 compared to the same period in 2012. Our average capacity factor, excluding peakers decreased 8% resulting from lower generation as well as the sale of Riverside Energy Center. Average total MW in operation decreased 594 MW, or 8%, due primarily to the sale of Riverside Energy Center partially offset by an increase in capacity resulting from our turbine modernization program.

Southeast:	2013	2012	Change	% Change
Commodity Margin (in millions)	$41	$56	$(15)	(27)
Commodity Margin per MWh generated	$11.02	$9.79	$1.23	13
MWh generated (in thousands)	3,722	5,722	(2,000)	(35)
Average availability	94.1 %	94.1 %	— %	—
Average total MW in operation	5,236	6,083	(847)	(14)
Average capacity factor, excluding peakers	33.7 %	48.7 %	(15.0)%	(31)
Steam Adjusted Heat Rate	7,269	7,271	2	—

Southeast — Commodity Margin in our Southeast segment decreased by $15 million, or 27%, for the three months ended March 31, 2013 compared to the same period in 2012, primarily due to the sale of Broad River in December 2012. Commodity Margin for the balance of our Southeast segment was relatively unchanged during the first quarter of 2013 compared to the first quarter of 2012 as we experienced the positive impact from a new tolling contract which became effective in January 2013 and higher contribution from hedges; however, these positive factors were offset by a decrease in Commodity Margin driven by lower Spark Spreads and 35% lower generation primarily due to a reversal of coal-to-gas switching during the first quarter of 2013 compared to same period in 2012. Our average total

MW in operation for the three months ended March 31, 2013 compared to the same period in 2012 decreased 847 MW, or 14%, due to the sale of Broad River.

Adjusted EBITDA

The tables below provide a reconciliation of Adjusted EBITDA to our income (loss) from operations on a segment basis and to net loss attributable to Calpine on a consolidated basis for the periods indicated (in millions).

	Three Months Ended March 31, 2013					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Net loss attributable to Calpine						$(125)
Income tax benefit						(50)
Other (income) expense, net						5
Interest expense, net of interest income						174
Income (loss) from operations	$8	$(64)	$67	$(8)	$1	$4
Add:						
Adjustments to reconcile income (loss) from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs[1]	51	43	33	19	—	146
Major maintenance expense	24	26	8	8	—	66
Operating lease expense	2	—	7	—	—	9
Unrealized (gain) loss on commodity derivative mark-to-market activity	48	18	(5)	(4)	—	57
Adjustments to reflect Adjusted EBITDA from unconsolidated investments[2][3]	—	—	6	—	—	6
Stock-based compensation expense	2	4	1	1	—	8
Loss on dispositions of assets	—	2	—	—	—	2
Acquired contract amortization	—	—	4	—	—	4
Other	(9)	(1)	(4)	(1)	(1)	(16)
Total Adjusted EBITDA	$126	$28	$117	$15	$—	$286

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	Three Months Ended March 31, 2012					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Net loss attributable to Calpine						$(9)
Income tax benefit						(6)
Debt extinguishment costs and other (income) expense, net						14
Loss on interest rate derivatives						14
Interest expense, net of interest income						182
Income from operations	$94	$27	$72	$1	$1	$195
Add:						
Adjustments to reconcile income from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs[1]	50	35	33	24	(1)	141
Major maintenance expense	10	23	7	6	—	46
Operating lease expense	2	—	7	—	—	9
Unrealized (gain) on commodity derivative mark-to-market activity	(30)	(29)	(10)	(9)	—	(78)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments[2][3]	—	—	7	—	—	7
Stock-based compensation expense	2	2	1	1	—	6
Loss on dispositions of assets	1	1	—	—	—	2
Acquired contract amortization	—	—	4	—	—	4
Other	(4)	—	(4)	1	—	(7)
Total Adjusted EBITDA	$125	$59	$117	$24	$—	$325

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(1) Depreciation and amortization expense on our Consolidated Condensed Statements of Operations excludes amortization of other assets.

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

(3) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include unrealized (gain) loss on mark-to-market activity of nil for each of the three months ended March 31, 2013 and 2012.

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LIQUIDITY AND CAPITAL RESOURCES

We maintain a strong focus on liquidity. We manage our liquidity to help provide access to sufficient funding to meet our business needs and financial obligations throughout business cycles.

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 is dependent on maintaining sufficient liquidity. We believe that we have adequate resources from a combination of cash and cash equivalents on hand and cash expected to be generated from future operations to continue to meet our obligations as they become due.

Liquidity

At March 31, 2013, we had $962 million in cash and cash equivalents and $199 million of restricted cash. Amounts available for future borrowings were $778 million under our Corporate Revolving Facility. The following table provides a summary of our liquidity position at March 31, 2013 and December 31, 2012 (in millions):

	March 31, 2013	December 31, 2012
Cash and cash equivalents, corporate(1)	$786	$1,153
Cash and cash equivalents, non-corporate	176	131
Total cash and cash equivalents	962	1,284
Restricted cash	199	253
Corporate Revolving Facility availability	778	757
CDHI letter of credit facility availability(2)	—	—
Total current liquidity availability	$1,939	$2,294

(1) Includes $1 million and $11 million of margin deposits posted with us by our counterparties at March 31, 2013 and December 31, 2012, respectively.

(2) As a result of the completion of the sale of Riverside Energy Center, LLC, a wholly-owned subsidiary of CDHI, on December 31, 2012, we are required to cash collateralize letters of credit issued in excess of $225 million until replacement collateral is contributed to the CDHI collateral package, which we are in the process of arranging. At March 31, 2013, we had $25 million in outstanding letters of credit issued in excess of $225 million under our CDHI letter of credit facility that were collateralized by cash. We do not believe that this change will have a material impact on our liquidity.

Our principal source for future liquidity is cash flows generated from our operations. Our principal uses of liquidity and capital resources, outside of those required for our operations, include, but are not limited to, collateral requirements to support our commercial hedging and optimization activities, debt service obligations including principal and interest payments, and capital expenditures for construction, project development and other growth initiatives. In addition, we may use capital resources to opportunistically repurchase our shares of common stock. The ultimate decision to allocate capital to share repurchases will be based upon the expected returns compared to alternative uses of capital. We believe that cash on hand and expected future cash flows from operations will be sufficient to meet our liquidity needs for our operations, both in the near and longer term.

Cash Management — We manage our cash in accordance with our cash management system subject to the requirements of our Corporate Revolving Facility and requirements under certain of our project debt and lease agreements or by regulatory agencies. Our cash and cash equivalents, as well as our restricted cash balances, 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 creditworthy financial institutions and certain of our money market accounts invest in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. Government, its agencies or instrumentalities.

We have never paid cash dividends on our common stock. Future cash dividends, if any, will be at the discretion of our Board of Directors and will depend upon, among other things, our future operations and earnings, capital requirements, general financial condition, contractual and financing restrictions and such other factors as our Board of Directors may deem relevant.

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 April 26, 2013, an increase of $1/MMBtu in natural gas prices would result in an increase of collateral required by approximately $232 million. If natural gas prices decreased by $1/MMBtu, we estimate that our collateral requirements would decrease by approximately $165 million. Changes in Market Heat Rates also affect our liquidity. For example, as demand increases, less efficient generation is dispatched, which increases the Market Heat Rate and results in increased collateral requirements. Historical relationships of natural gas and Market Heat Rate movements for our portfolio of assets have been volatile over time and are influenced by the absolute price of natural gas and the regional characteristics of each power market. We estimate that at April 26, 2013, an increase of 500 Btu/KWh in the Market Heat Rate would result in an increase in collateral required by approximately $40 million. If Market Heat Rates were to fall at a similar rate, we estimate that our collateral required would decrease by $37 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, and also exclude any correlation between the changes in natural gas prices and Market Heat Rates that may occur concurrently. These sensitivities will change as new contracts or hedging activities are executed.

In order to effectively manage our future Commodity Margin, historically we have economically hedged a portion of our generation and natural gas portfolio mostly through power and natural gas forward physical and financial transactions; however, we currently remain susceptible to significant price movements for 2013 and beyond. In addition to the price of natural gas, the future impact on our Commodity Margin is highly dependent on other factors such as:

- the level of Market Heat Rates;
- our continued ability to successfully hedge our Commodity Margin;
- the speed, strength and duration of an economic recovery;
- maintaining acceptable availability levels for our fleet;
- the impact of current and pending environmental regulations in the markets in which we participate;
- improving the efficiency and profitability of our operations;
- increasing future contractual cash flows; and
- our significant counterparties performing under their contracts with us.

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

Our letters of credit, capital management, construction, upgrades and growth initiatives are further discussed below.

Letter of Credit Facilities

The Corporate Revolving Facility represents our primary revolving facility. The table below represents amounts issued under our letter of credit facilities at March 31, 2013 and December 31, 2012 (in millions):

	March 31, 2013	December 31, 2012
Corporate Revolving Facility	$222	$243
CDHI	250	253
Various project financing facilities	131	130
Total	$603	$626

Capital Management and Significant Financing Transactions

In connection with our goals of enhancing long-term shareholder value and leveraging our three scale regions, we have completed, made progress toward completing or initiated certain key capital and financing transactions during 2013, as further described below.

Share Repurchase Program

In February 2013, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock, bringing the cumulative authorization total to $1.0 billion. As of the filing of this Report, we have repurchased a total of

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3,034,797 shares of our outstanding common stock under the additional $400 million authorization for approximately $58 million at an average price paid of $18.97 per share.

First Lien Term Loans Repricing

In February 2013, we repriced our First Lien Term Loans by lowering the LIBOR floor by 0.25% to 1.0% and lowering the LIBOR margin by 0.25% to 3.0%. We estimate that this repricing will lower our annual interest expense by approximately $12 million.

CCFC Refinancing

On April 22, 2013, we announced that CCFC, our indirect, wholly-owned subsidiary, is pursuing a potential debt refinancing whereby CCFC will enter into a new senior secured term loan and the funds will be used to repay the CCFC Notes. The timing, size and terms of any potential refinancing and the use of proceeds thereof are subject to market and other conditions and we make no assurance that such actions will take place.

Construction, Modernizations and Growth Initiatives

We remain focused on our goal to continue to grow our presence in core markets with an emphasis on expansions or modernizations of existing power plants. We intend to take advantage of favorable opportunities to continue to design, develop, acquire, construct and operate the next generation of highly efficient, operationally flexible and environmentally responsible power plants where such investment meets our rigorous financial hurdles, particularly if power contracts and financing are available and attractive returns are expected. Likewise, we will actively seek divestiture opportunities on our non-core assets if those opportunities meet our financial expectations. In addition, we believe that modernizations and expansions to our current assets or using existing equipment offer proven and financially disciplined opportunities to improve our operations, capacity and efficiencies. Our significant projects under construction, growth initiatives and modernizations are discussed below.

West:

Russell City Energy Center — Construction at our Russell City Energy Center continues to move forward. Upon completion, this project will bring on line approximately 429 MW of net interest baseload capacity (464 MW with peaking capacity) representing our 75% share. Construction is ongoing and COD is expected in the third quarter of 2013. Upon completion, the Russell City Energy Center is contracted to deliver its full output to PG&E under a ten-year PPA.

Los Esteros Critical Energy Facility — During 2009, we and PG&E negotiated a new PPA to replace the existing California Department of Water Resources contract and facilitate the modernization of our Los Esteros Critical Energy Facility from a 188 MW simple-cycle generation power plant to a 309 MW combined-cycle generation power plant, which will also increase the efficiency and environmental performance of the power plant by lowering the Heat Rate. Construction is ongoing and COD is expected in the third quarter of 2013.

Texas:

Channel and Deer Park Expansions — In September and November 2011, we filed air permit applications with the TCEQ and the EPA to expand the baseload capacity of our Deer Park and Channel Energy Centers by approximately 260 MW each. We received air permit approvals from the TCEQ for our Deer Park and Channel expansion projects in September and October 2012, respectively, and from the EPA in November 2012. Construction on these expansion projects commenced in the fourth quarter of 2012. We expect COD during the second quarter of 2014 for these expansions and are currently evaluating funding sources including, but not limited to, nonrecourse financing, corporate financing or internally generated funds.

North:

Garrison Energy Center — We continue to advance the development of as much as 618 MW of combined-cycle capacity in Delaware at a site secured by a long-term lease with the City of Dover. We are pursuing the development of this project in two separate phases. The capacity from the first phase (309 MW) cleared PJM’s 2015/2016 base residual auction. Construction on the first phase commenced in April 2013, and we expect COD by the second quarter of 2015. We are currently evaluating funding sources for this phase of development, including, but not limited to, nonrecourse financing, corporate financing or internally generated funds. With respect to the second phase (309 MW), we are in early stages of development. PJM has completed a feasibility study for this phase and the system impact study is currently underway.

Deepwater Energy Center — We are currently evaluating our Deepwater facility since the existing 158 MW fossil fuel steam-based power plant will be decommissioned by May 1, 2015. The Deepwater development opportunity would add approximately 350 MW of new combined-cycle capacity and leverage existing infrastructure. Several outstanding early development issues must be resolved before the project will be advanced.

Mankato Power Plant Expansion — We are proposing a 345 MW expansion of the Mankato Power Plant in response to a competitive resource acquisition process established by the Minnesota Public Utilities Commission ("MPUC"). The process, which will be managed via a contested case hearing, is intended to address a capacity shortfall in the Northern States Power service territory of up to 500 MW over the 2017 to 2019 time frame. The MPUC will evaluate proposals for intermediate and/or peaking capacity to meet all or part of the 500 MW needed. We expect that winning bidders will be identified in the fourth quarter of 2013.

All Segments:

Turbine Modernization — We continue to move forward with our turbine modernization program. Through March 31, 2013, we have completed the upgrade of eleven Siemens and eight GE turbines totaling approximately 200 MW and have committed to upgrade approximately five additional turbines. Similarly, we have the opportunity at several of our power plants in Texas to implement further modernizations to add as much as 300 MW of incremental capacity across the region at attractive prices. Our decision to invest in these modernizations depends upon, among other things, further clarity on market design reforms currently being considered by the PUCT.

NOLs

We have significant NOLs that will provide future tax deductions when we generate sufficient taxable income during the applicable carryover periods. At December 31, 2012, our consolidated federal NOLs totaled approximately $7.3 billion.

Cash Flow Activities

The following table summarizes our cash flow activities for the three months ended March 31, 2013 and 2012 (in millions):

	2013	2012
Beginning cash and cash equivalents	$1,284	$1,252
Net cash provided by (used in):		
Operating activities	(157)	71
Investing activities	(122)	(314)
Financing activities	(43)	61
Net decrease in cash and cash equivalents	(322)	(182)
Ending cash and cash equivalents	$962	$1,070

Net Cash Provided By (Used In) Operating Activities

Cash used in operating activities for the three months ended March 31, 2013, was $157 million compared to cash provided by operating activities of $71 million for the three months ended March 31, 2012. The difference was primarily due to:

- Income from operations — Income from operations, adjusted for non-cash items decreased by $51 million for the three months ended March 31, 2013 as compared to the three months ended March 31, 2012. Non-cash items consist primarily of depreciation and amortization, income from unconsolidated investments and unrealized gains and losses in mark-to-market activity.
- Working capital employed — Working capital employed increased by approximately $226 million for the three months ended March 31, 2013 compared to the three months ended March 31, 2012 after adjusting for debt related balances and non-hedging interest rate swaps which did not impact cash provided by operating activities. The increase is primarily due to increased margin requirements during the three months ended March 31, 2013, resulting from higher commodity prices, combined with a decrease in working capital required for net accounts receivable and accounts payable during the three months ended March 31, 2012, resulting from falling commodity prices and the expiration of calendar year hedges that were in place during 2011.
- Interest paid — Cash paid for interest decreased by $13 million to $213 million for the three months ended March 31, 2013, as compared to $226 million for the three months ended March 31, 2012. The decrease was primarily due to the November 2012 redemption of 10% of the aggregate principal amount of each series of our fixed interest rate First Lien Notes with a corporate level term loan at a variable interest rate and the February 2013 repricing of our First

Lien Term Loans.

- Debt extinguishment payments — In March 2012, we made cash payments of $12 million associated with the purchase of two of the third party interests in GEC Holdings, LLC. The payments were recorded as debt extinguishment costs as the preferred interests were classified as debt under U.S. GAAP. We made no similar payments during the three months ended March 31, 2013.

Net Cash Used In Investing Activities

Cash flows used in investing activities for the three months ended March 31, 2013 was $122 million compared to $314 million for the three months ended March 31, 2012. The difference was primarily due to:

- Settlement of non-hedging interest rate swaps — During the three months ended March 31, 2012, we terminated our legacy interest rate swaps formerly hedging our First Lien Credit Facility resulting in payments of approximately $151 million. We made no similar payments in the three months ended March 31, 2013.
- Restricted cash — The decrease in restricted cash was $54 million for three months ended March 31, 2013 compared to $23 million for the same period in 2012. The higher decrease in restricted cash in 2013 as compared to 2012 was primarily due to a release of cash collateral related to lower exposure on letter of credit facilities and reduced major maintenance reserve requirements resulting from our plant outage schedule.
- Transmission credits — During the three months ended March 31, 2012, we paid $8 million for transmission credits related to the construction of our Russell City Energy Center. We made no similar payments during the three months ended March 31, 2013.

Net Cash Provided By (Used In) Financing Activities

Cash flows used in financing activities were $43 million for the three months ended March 31, 2013, compared to cash flows provided by financing activities of $61 million for the three months ended March 31, 2012. The difference was primarily due to:

- Lower proceeds from project debt — During the three months ended March 31, 2013, we received proceeds of approximately $73 million from project debt compared to $114 million for the three months ended March 31, 2012. The decrease was related to lower draws on our Russell City and Los Esteros project debt.
- Stock repurchases — During the three months ended March 31, 2013, we made payments under the share repurchase program of approximately $75 million compared to $6 million during the three months ended March 31, 2012.
- Stock option proceeds — During the three months ended March 31, 2013, we received proceeds from the exercise of stock options of approximately $9 million compared to nil during the three months ended March 31, 2012.

Off Balance Sheet Arrangements

There have been no material changes to any off balance sheet arrangements from those disclosed in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” of our 2012 Form 10-K.

Special Purpose Subsidiaries

Pursuant to applicable transaction agreements, we have established certain of our entities separate from Calpine Corporation 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: GEC Holdings, LLC, Gilroy Energy Center, LLC, Creed, Goose Haven, Calpine Gilroy Cogen, L.P., Calpine Gilroy 1, Inc., Calpine King City Cogen, LLC, Calpine Securities Company, L.P. (a parent company of Calpine King City Cogen, LLC), Calpine King City, LLC (an indirect parent company of Calpine Securities Company, L.P.), Russell City Energy Company, LLC and Otay Mesa Energy Center, LLC.

RISK MANAGEMENT AND COMMODITY ACCOUNTING

Our commercial hedging and optimization strategies are designed to maximize our risk-adjusted Commodity Margin by leveraging our knowledge, experience and fundamental views on natural gas and power. We actively manage our risk exposures with a variety of physical and financial instruments with varying time horizons. These instruments include PPAs, tolling arrangements, Heat Rate swaps and options, load sales, steam sales, buying and selling standard physical products, buying and selling exchange traded instruments, gas transportation and storage arrangements, electric transmission service and other contracts for the sale and purchase of power products.

We conduct our hedging and optimization activities within a structured risk management framework based on controls, policies and procedures. We monitor these activities through active and ongoing management and oversight, defined roles and responsibilities, and daily risk measurement and reporting. Additionally, we seek to manage the associated risks through diversification, by controlling position sizes, by using portfolio position limits, and by entering into offsetting positions that lock in a margin. We 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 or we do not elect either hedge accounting or the normal purchase normal sale exemption are recognized currently in earnings and are separately stated on our Consolidated Condensed Statements of Operations in unrealized mark-to-market gain/loss as a component of operating revenues (for power contracts and Heat Rate swaps and options) and fuel and purchased energy expense (for natural gas contracts, swaps and options). Our future hedged status and marketing and optimization activities are subject to change as determined by our commercial operations group, Chief Risk Officer, senior management and Board of Directors.

In order to simplify our reporting, we elected to discontinue the application of hedge accounting treatment during the first quarter of 2012 for all commodity derivatives, including the remaining commodity derivatives previously accounted for as cash flow hedges. Accordingly, prospective changes in fair value from the date of this election are reflected in unrealized mark-to-market activity on our Consolidated Condensed Statements of Operations and could create more volatility in our earnings. The fair value of our commodity derivative instruments residing in AOCI during the previous application of hedge accounting was reclassified to earnings during 2012 as the related economic transactions affected earnings or the forecasted transaction became probable of not occurring.

At any point in time, the relative quantity of our products hedged or sold under longer-term contracts is determined by the availability of forward product sales opportunities and our view of the attractiveness of the pricing available for forward sales. Historically, we have economically hedged a portion of our expected generation and natural gas portfolio mostly through power and natural gas forward physical and financial transactions; however, we currently remain susceptible to significant price movements for 2013 and beyond. When we elect to enter into these transactions, we are able to economically hedge a portion of our Spark Spread at pre-determined generation and price levels.

We have historically used interest rate swaps to adjust the mix between our fixed and variable rate debt. To the extent eligible, our interest rate swaps have been designated as cash flow hedges, and changes in fair value are recorded in OCI to the extent they are effective with gains and losses reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. See Note 5 of the Notes to Consolidated Condensed Financial Statements for further discussion of our derivative instruments.

The primary factors affecting our market risk and the fair value of our derivatives at any point in time are the volume of open derivative positions (MMBtu, MWh and $ notional amounts); changing commodity market prices, primarily for power and natural gas; our credit standing and that of our counterparties for energy commodity derivatives; and prevailing interest rates for our interest rate swaps. Since prices for power and natural gas and interest rates are volatile, there may be material changes in the fair value of our derivatives over time, driven both by price volatility and the changes in volume of open derivative transactions. Our derivative assets have increased to approximately $0.7 billion at March 31, 2013, when compared to approximately $0.4 billion at December 31, 2012, and our derivative liabilities have increased to approximately $0.9 billion at March 31, 2013, compared to approximately $0.6 billion at December 31, 2012. At March 31, 2013, the fair value of our level 3 derivative assets and liabilities represent only a small portion of our total assets and liabilities measured at fair value (approximately 1%). See Note 4 of the Notes to

Consolidated Condensed Financial Statements for further information related to our level 3 derivative assets and liabilities.

The change in fair value of our outstanding commodity and interest rate derivative instruments from January 1, 2013, through March 31, 2013, is summarized in the table below (in millions):

	Commodity Instruments	Interest Rate Swaps	Total
Fair value of contracts outstanding at January 1, 2013	$(17)	$(196)	$(213)
Items recognized or otherwise settled during the period[1][2]	(21)	9	(12)
Fair value attributable to new contracts	33	—	33
Changes in fair value attributable to price movements	(33)	4	(29)
Changes in fair value attributable to nonperformance risk	—	—	—
Fair value of contracts outstanding at March 31, 2013[3]	$(38)	$(183)	$(221)

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(1) Gains on settlement of commodity contracts not designated as hedging instruments of $40 million (represents a portion of Commodity revenue and Commodity expense as reported on our Consolidated Condensed Statements of Operations) and $19 million related to recognition of losses from other changes in derivative assets and liabilities not reflected in OCI or earnings.

(2) Interest rate settlements consist of $6 million related to recognition of losses from settlements of designated cash flow hedges and $3 million in losses from settlements of undesignated interest rate swaps (represents a portion of interest expense as reported on our Consolidated Condensed Statements of Operations).

(3) Net commodity and interest rate derivative assets and liabilities reported in Notes 4 and 5 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 earnings.

The following tables detail the components of our total mark-to-market activity for both the net realized gain (loss) and the net unrealized gain (loss) recognized from our derivative instruments in earnings and where these components were recorded on our Consolidated Condensed Statements of Operations for the periods indicated (in millions):

	Three Months Ended March 31,	
	2013	2012
Realized gain (loss)[1]		
Commodity derivative instruments	$28	$118
Interest rate swaps	—	(157)
Total realized gain (loss)	$28	$(39)
Unrealized gain (loss)[2]		
Commodity derivative instruments	$(57)	$78
Interest rate swaps	2	146
Total unrealized gain (loss)	$(55)	$224
Total mark-to-market activity, net	$(27)	$185

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(1) Does not include the realized value associated with derivative instruments that settle through physical delivery.

(2) In addition to changes in market value on derivatives not designated as hedges, changes in unrealized gain (loss) also includes hedge ineffectiveness and adjustments to reflect changes in credit default risk exposure.

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	Three Months Ended March 31,	
	2013	2012
Realized and unrealized gain (loss)		
Derivatives contracts included in operating revenues	$(74)	$92
Derivatives contracts included in fuel and purchased energy expense	45	104
Interest rate swaps included in interest expense	2	3
Loss on interest rate derivatives	—	(14)
Total mark-to-market activity, net	$(27)	$185

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

The net fair value of outstanding derivative commodity instruments at March 31, 2013, based on price source and the period during which the instruments will mature, are summarized in the table below (in millions):

Fair Value Source	2013	2014-2015	2016-2017	After 2017	Total
Prices actively quoted	$(13)	$11	$(9)	$—	$(11)
Prices provided by other external sources	(29)	(1)	1	—	(29)
Prices based on models and other valuation methods	—	2	—	—	2
Total fair value	$(42)	$12	$(8)	$—	$(38)

We measure the energy commodity price risks in our portfolio on a daily basis using a VAR model to estimate the potential one-day risk of loss based upon historical experience resulting from market movements in comparison to internally established thresholds. Our VAR is calculated for our entire portfolio which is comprised of energy commodity derivatives, expected generation and natural gas consumption from our power plants, PPAs, and other physical and financial transactions. During the first quarter of 2013, we changed our portfolio VAR calculation which previously incorporated positions for the remaining portion of the current calendar year, exclusive of the current month of measurement, plus the following two calendar years to incorporate positions on a rolling thirty-six month basis which enables the market risk exposure of the portfolio to be measured and compared more consistently throughout the year. The 2012 VAR data in the table below has been updated to reflect this change in model parameter so that the VAR data provided for both periods presented below is comparable. No other key model parameters were changed. We measure VAR using a variance/covariance approach based on a confidence level of 95%, a one-day holding period and actual observed historical correlation. While we believe that our VAR assumptions and approximations are reasonable, different assumptions and/or approximations could produce materially different estimates.

The table below presents the high, low and average of our daily VAR for the three months ended March 31, 2013 and 2012 (in millions):

	2013	2012
Three months ended March 31:		
High	$80	$49
Low	$42	$33
Average	$63	$41
As of March 31	$45	$48

Due to the inherent limitations of statistical measures such as VAR, the VAR calculation may not capture the full extent of our commodity price exposure. As a result, actual changes in the value of our energy commodity portfolio could be different from the calculated VAR, and could have a material impact on our financial results. In order to evaluate the risks of our portfolio on a comprehensive basis and augment our VAR analysis, we also measure the risk of the energy commodity portfolio using several analytical methods including sensitivity tests, scenario tests, stress tests, and daily position reports.

During the fourth quarter of 2012 and into the first quarter of 2013, we began to experience diminished liquidity in the forward commodity markets resulting from a decrease in participation of counterparties in the marketplace with which to transact our hedging activities. Although this occurrence of diminished liquidity has not had a material adverse impact on our results of operations or financial condition, should these conditions persist, it could decrease our ability to hedge our forward commodity price risk and create more volatility in our earnings.

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 6 of the Notes to Consolidated Condensed Financial Statements.

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

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

We have concentrations of credit risk with a few of our commercial customers, primarily independent electric system operators, relating to our sales of power, steam and hedging and optimization activities. We believe that our credit policies and portfolio of transactions adequately monitor our credit risk, and currently our counterparties are performing and financially settling timely according to their respective agreements. We monitor and manage our total comprehensive credit risk associated with all of our contracts and PPAs irrespective of whether they are accounted for as an executory contract, a normal purchase normal sale or whether they are marked-to-market and included in our derivative assets and liabilities on our Consolidated Condensed Balance Sheets. Our counterparty credit quality associated with the net fair value of outstanding derivative commodity instruments is included in our derivative assets and liabilities at March 31, 2013, and the period during which the instruments will mature are summarized in the table below (in millions):

Credit Quality (Based on Standard & Poor’s Ratings as of March 31, 2013)	2013	2014-2015	2016-2017	After 2017	Total
Investment grade	$(44)	$12	$(8)	$—	$(40)
Non-investment grade	1	—	—	—	1
No external ratings	1	—	—	—	1
Total fair value	$(42)	$12	$(8)	$—	$(38)

Interest Rate Risk — Our variable rate financings are indexed to base rates, generally LIBOR. Interest rate risk represents the potential loss in earnings arising from adverse changes in market interest rates. The fair value of our interest rate swaps are validated based upon external quotes. Our interest rate swaps are with counterparties we believe are primarily high quality institutions, and we do not believe that our interest rate swaps expose us to any significant credit risk. Holding all other factors constant, we estimate that a 10% decrease in interest rates would result in a change in the fair value of our interest rate swaps hedging our variable rate debt of approximately $(10) million at March 31, 2013.

New Accounting Standards and Disclosure Requirements

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The information required to be disclosed under this Item 3 is set forth under Item 2 “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Risk Management and Commodity Accounting.” This information should be read in conjunction with the information disclosed in our 2012 Form 10-K.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

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

Changes in Internal Control Over Financial Reporting

During the first quarter of 2013, there were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) 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 10 of the Notes to Consolidated Condensed Financial Statements for a description of our legal proceedings.

Item 1A. Risk Factors

There were no material changes to the description of the risk factors associated with our business previously disclosed in Part I, Item 1A "Risk Factors" of our 2012 Form 10-K.

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

Repurchase of Equity Securities

Period	(a) Total Number of Shares Purchased[1]	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[2]	(d) Maximum Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (in millions)
January	995,721	$18.05	995,083	$—
February	1,250,395	$18.71	921,600	$383
March	2,069,969	$19.05	2,069,625	$343
Total	4,316,085	$18.72	3,986,308	$343

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(1) 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 satisfy their tax withholding obligations in cash. During the first quarter of 2013, we withheld a total of 329,777 shares that are included in total number of shares purchased.

(2) In February 2013, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock, bringing the cumulative authorization total to $1.0 billion. As of the filing of this Report, we have repurchased a total of 3,034,797 shares of our outstanding common stock under the additional $400 million authorization for approximately $58 million at an average price paid of $18.97 per share. The shares repurchased under our share repurchase program were purchased in open market transactions and are held as treasury stock.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not Applicable.

Item 5. Other Information

None.

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Item 6. Exhibits
EXHIBIT INDEX

Exhibit Number	Description
10.1	Amendment to the Executive Employment Agreement between the Company and Jack A. Fusco, dated February 28, 2013 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on March 4, 2013). †
10.2	Amendment to the Executive Employment Agreement between the Company and W. Thaddeus Miller, dated February 28, 2013 (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on March 4, 2013). †
10.3	Form of Restricted Stock Award Agreement between the Company and Jack A. Fusco and W. Thaddeus Miller, dated February 28, 2013 (incorporated by reference to Exhibit 10.3 to Calpine's Current Report on Form 8-K filed with the SEC on March 4, 2013). †
10.4	Form of Restricted Stock Award Agreement between the Company and John B. (Thad) Hill, Zamir Rauf and Jim D. Deidiker, dated February 28, 2013 (incorporated by reference to Exhibit 10.4 to Calpine's Current Report on Form 8-K filed with the SEC on March 4, 2013). †
10.5	Form of Performance Share Unit Award Agreement between the Company and Jack A. Fusco and W. Thaddeus Miller, dated February 28, 2013 (incorporated by reference to Exhibit 10.5 to Calpine's Current Report on Form 8-K filed with the SEC on March 4, 2013). †
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10.10	Amendment to the Credit Agreement, dated February 15, 2013 among Calpine Corporation as borrower and the lenders party hereto, and Morgan Stanley Senior Funding, Inc., as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, Barclays Bank PLC, Deutsche Bank Securities Inc., and RBC Capital Markets, as co-documentation agents.
31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1	Certification of the Chief Executive Officer and the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. *
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF	XBRL Taxonomy Extension Definition Linkbase.
101.LAB	XBRL Taxonomy Extension Label Linkbase.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Furnished herewith.

† Management contract or compensatory plan, contract or arrangement.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this Report to be signed on its behalf by the undersigned thereunto duly authorized.

CALPINE CORPORATION
(Registrant)

By: /s/ ZAMIR RAUF
Zamir Rauf
Executive Vice President and Chief Financial Officer

Date: May 1, 2013

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10.10	Amendment to the Credit Agreement, dated February 15, 2013 among Calpine Corporation as borrower and the lenders party hereto, and Morgan Stanley Senior Funding, Inc., as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, Barclays Bank PLC, Deutsche Bank Securities Inc., and RBC Capital Markets, as co-documentation agents.
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