CALPINE®

NYSE CPN

2013 ANNUAL REPORT

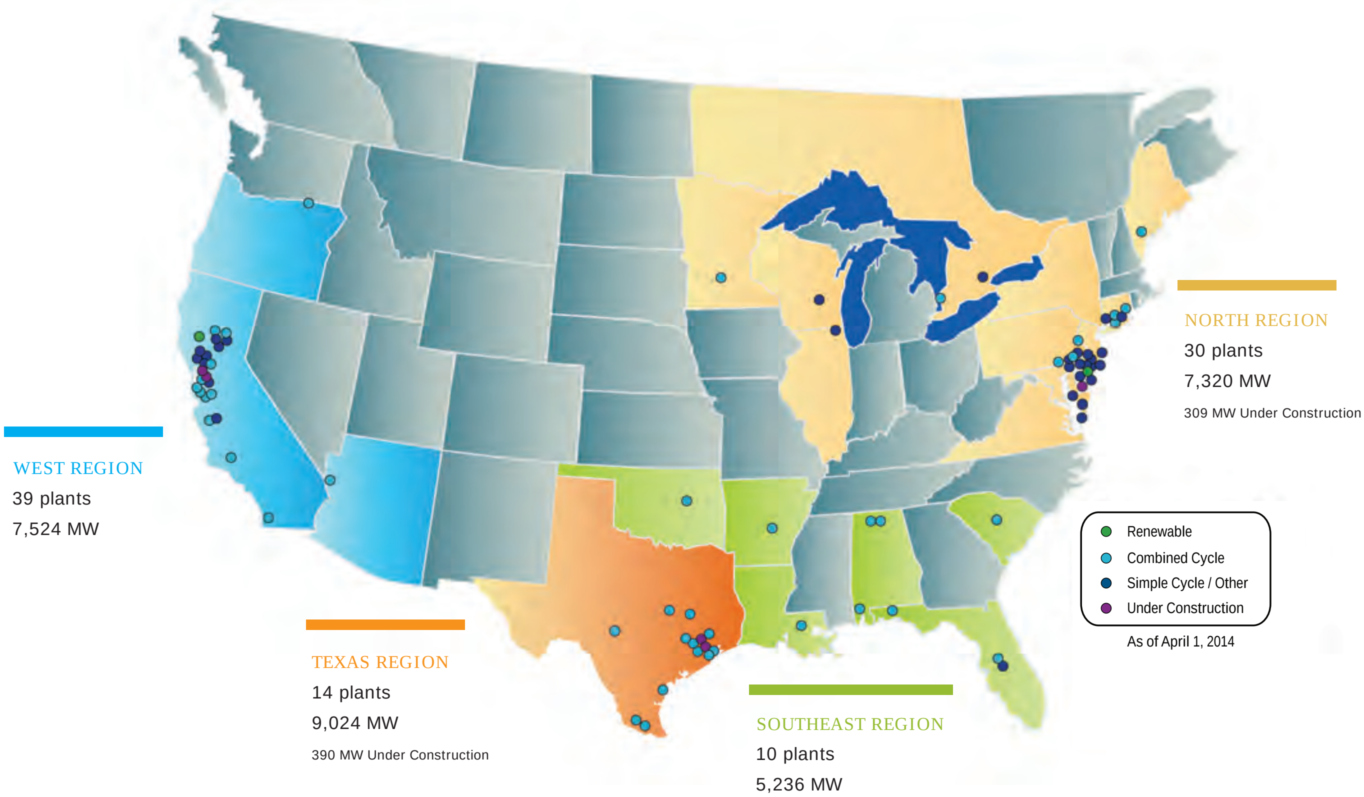
In 2013, we brought online more than 900 MW of combined-cycle capacity in California now operating under 10-year contracts, including our Los Esteros Critical Energy Facility.

Calpine: A Multi-Faceted Investment

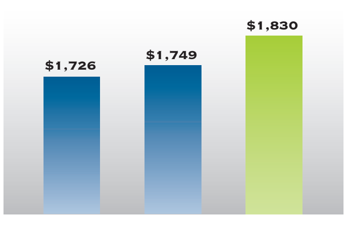
Calpine is a multi-faceted investment and a cash flow generator. We are bigger than just one market, one trend, or one financial driver. Our geographic diversity and flexible fleet provide a competitive advantage in today's transforming power generation industry. Our cash flows are enhanced by our ability to continue effectively allocating capital in a disciplined, balanced manner through buying or building strategically positioned assets at attractive prices, selling non-core assets to unlock value and opportunistically returning capital to shareholders through share repurchases. These attributes drive our ability to deliver strong Adjusted Free Cash Flow Per Share growth, which we believe differentiates Calpine from its peers and makes for a compelling value proposition.

As America moves toward clean, affordable natural gas as the preferred fuel for power generation and as the electric grid requires more flexible power generation to integrate intermittent renewable power to assure reliability of electric supply, we believe Calpine's fleet is uniquely positioned to benefit from the combination of these secular and fundamental trends that favor combined-cycle natural gas-fired power generation as the technology of choice for America's future.

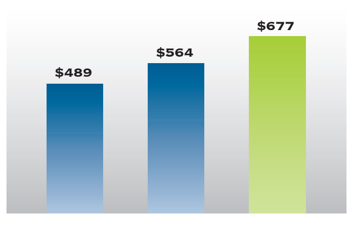
National Portfolio of more than 29,000 MW in Operation



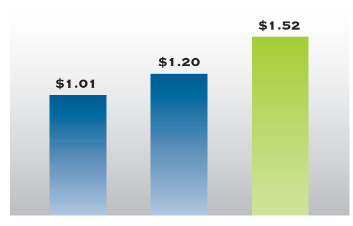
Adjusted EBITDA ($ millions)



Adjusted Free Cash Flow ($ millions)



Adjusted Free Cash Flow Per Share



All MW figures shown represent Calpine's net ownership interest.

Fellow Shareholders,

In 2013, I celebrated my five year anniversary at Calpine. I recall being asked by investors during the early days: what attracted you to Calpine? The answer came easily: great assets and great people. The same holds true today. Unlike any other in the industry, Calpine features the right fleet, at the right place, at the right time with the right people to develop and execute our strategy.

Right Fleet

The transformation that is now underway in the U.S. power market – an increasing prioritization of flexibility and reliability by our customers – is further enhancing the value of our fleet. The cleanliness, efficiency and affordability of our power generation assets has always made them a valuable resource. But more and more, our customers want the operating attributes they need, not just "steel in the ground."

With increasing reliance on intermittent renewables and localized natural gas supply constraints chief among their concerns, customers need products like flexible, quick-ramping generation, black-start capabilities and dual-fuel resources that can burn either natural gas or fuel oil. To the extent that customers continue to increasingly value these attributes, markets must evolve to differentiate those generators capable of providing them and to compensate them accordingly. Our fleet is uniquely and ideally positioned to respond to these conditions. Our ability to cycle overnight, to ramp quickly in response to variable loads, and (in the case of PJM) to do so reliably as a result of our dual-fuel capabilities means that the transformation that is underway in our nation's power markets is one that benefits our fleet.

Meanwhile, we continue to demonstrate best-in-class operations. In 2013, the Calpine team delivered record performance, achieving our lowest-ever forced outage factor and our highest-ever starting reliability. When our customers needed us, we were there.

Right Place

We are geographically diversified and have scale in America's major competitive wholesale power markets, having redeployed capital from non-core markets to strengthen our strategic position. Within our core markets, we continue to pursue financially disciplined growth. In 2013, we completed the construction of our Los Esteros and Russell City Energy Centers in California, bringing online more than 900 MW of combined-cycle technology now operating under 10-year contracts with our customer. We also advanced the expansions of our Deer Park and Channel Energy Centers in Texas and broke ground on the construction of our Garrison Energy Center in Delaware. These projects, totaling approximately 700 MW, are expected to begin commercial operation in the second quarters of 2014 and 2015, respectively. Lastly, we announced and have since closed on the acquisition of the approximately 1,000 MW Guadalupe Energy Center in Texas. We continue to look for opportunities to strategically invest in growth in our core markets, always mindful that we have an alternative investment that we believe offers attractive returns: reinvesting in our existing portfolio through share repurchases.

We have expanded our fleet of efficient, combined-cycle power plants in Texas through the acquisition of Guadalupe Energy Center.

Right Time

Sustained low natural gas prices coupled with localized supply issues. Increasing penetration of intermittent renewable resources. More stringent environmental regulations. An aging electrical infrastructure. These are the secular trends we face today that will define the power generation sector of tomorrow. At this critical juncture, and in the face of these forces, Calpine is equipped to thrive. Each of these key trends points to the dawning of a new age of increased volatility in our power markets, and unlike baseload generators, Calpine's flexible fleet benefits from these conditions.

The heightened volatility is driven not only by temporal weather extremes (though we have seen plenty of these of late); it is also driven by longer-term natural gas and regional dynamics. On the natural gas front, the growing discount of

Marcellus Hub pricing to Henry Hub (outside of winter) stands to pressure older, less efficient plants in the Mid-Atlantic, potentially signaling another round of retirements. Furthermore, deliverability concerns of getting natural gas to the right places at the right times will continue to drive regional volatility. Meanwhile, underlying power dynamics in our core regions signal further volatility: in the East, driven by significant capacity retirements and increasing reliance on demand response to meet reserve margin requirements; in Texas, by an energy-only market dependent upon scarcity pricing; and in California, by an increasing reliance upon intermittent renewables.

New generation – whether to replace retiring units or to satisfy growing demand – will be needed in various portions of the U.S., and the flexibility, reliability and affordability of natural gas-fired generation makes it the compelling choice. Existing generation that offers flexibility and reliability needs to be compensated to stay online to support the increasing volatility in our markets. Calpine stands ready to capitalize on these trends.

Supporting Our Competitive Advantage

The competitively advantaged position enjoyed by Calpine's fleet is supported by several additional factors that the Calpine team works hard to deliver in order to maximize the value of the business:

- operating leverage provided by a scalable asset base and lean cost structure
- financial leverage, as demonstrated by the extensive value secured through our refinancing initiatives conducted over the past few years
- leadership in advocating for competitive wholesale power markets that provide transparency and appropriate formation of pricing signals and
- effective allocation of capital.

In 2013, we allocated approximately $400 million toward organic growth, including the commencement of construction at our Garrison Energy Center in Delaware.

In 2013, our capital allocation efforts resulted in the investment of nearly $400 million in growth capital, the refinancing or repricing of approximately $6 billion of our debt, and the repurchase of $623 million of our own shares of stock. The result of these efforts, when combined with our relentless focus on operational excellence throughout the business, was a 27% increase in Adjusted Free Cash Flow Per Share compared to 2012. My thanks and congratulations to the entire Calpine team for their efforts.

The work of our employees in 2013 didn't stop at the gates of our facilities or the doors of our offices. It extended into our communities, resulting in a total of nearly 200 new bicycles donated to The Boys and Girls Clubs of Greater Houston during the holidays, hundreds of new trees planted across the country in honor of Earth Day, more than 250 runners and cyclists challenging themselves for worthy causes in the MS-150 and Houston Marathon, and approximately $2 million donated to local and national charities. I am proud to be a part of such a dedicated team.

Calpine was recognized as the top corporate fundraising team in the 2013 Houston Marathon and Half Marathon, with more than $140,000 raised for two charities.

As I look ahead to 2014, I will begin my transition to a new role here at Calpine, that of Executive Chairman. During my time as Chief Executive Officer, we accomplished much; yet there is more work that lies ahead. I believe that Thad Hill, Calpine's next CEO, is the right person to lead the charge day-to-day, and he will have my full support in doing so. I remain committed to Calpine, still firm in the very belief that brought me here in the first place: that Calpine has the best assets and the best people in the business. I thank you all for your continued support of Calpine.

Sincerely,

Jack Fusco

Jack A. Fusco
Chief Executive Officer

CALPINE®

NYSE CPN

2013 FORM 10-K

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2013

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

For the transition period from to

Commission File No. 001-12079

CALPINE NYSE CPN

Calpine Corporation

(A Delaware Corporation)

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

717 Texas Avenue, Suite 1000, Houston, Texas 77002
Telephone: (713) 830-2000

Not Applicable
(Former Address)

Securities registered pursuant to Section 12(b) of the Act:
Calpine Corporation Common Stock, $0.001 Par Value

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

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 [ ]	Smaller reporting company [ ]
(Do not check if a smaller reporting company)	

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2013, the last business day of the registrant's most recently completed second fiscal quarter: approximately $9,361 million.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: Calpine Corporation: 422,950,351 shares of common stock, par value $0.001, were outstanding as of February 10, 2014.

DOCUMENTS INCORPORATED BY REFERENCE

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

Designated portions of the Proxy Statement relating to the 2014 Annual Meeting of Shareholders are incorporated by reference into Part III to the extent described therein.

CALPINE CORPORATION AND SUBSIDIARIES

FORM 10-K

ANNUAL REPORT
For the Year Ended December 31, 2013

TABLE OF CONTENTS

DEFINITIONS

As used in this annual report for the year ended December 31, 2013, 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
2017 First Lien Notes	The $1.2 billion aggregate principal amount of 7.25% senior secured notes due 2017, issued October 21, 2009
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
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
2020 First Lien Term Loan	The $390 million first lien senior secured term loan, dated October 23, 2013, among Calpine Corporation, as borrower, and the lenders party hereto, and Citibank, N.A., as administrative agent and Goldman Sachs Credit Partners L.P., as collateral agent
2021 First Lien Notes	The $2.0 billion aggregate principal amount of 7.50% senior secured notes due 2021, issued October 22, 2010
2022 First Lien Notes	The $750 million aggregate principal amount of 6.0% senior secured notes due 2022, issued October 31, 2013
2023 First Lien Notes	The $1.2 billion aggregate principal amount of 7.875% senior secured notes due 2023, issued January 14, 2011
2024 First Lien Notes	The $490 million aggregate principal amount of 5.875% senior secured notes due 2024, issued October 31, 2013
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) adjustments to exclude the Adjusted EBITDA related to the noncontrolling interest, (g) stock-based compensation expense, (h) gains or losses on sales, dispositions or retirements of assets, (i) non-cash gains and losses from foreign currency translations, (j) gains or losses on the repurchase or extinguishment of debt, (k) non-cash GAAP-related adjustments to levelize revenues from tolling contracts and (l) 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

ABBREVIATION	DEFINITION
Average capacity factor, excluding peakers	A measure of total actual generation as a percent of total potential generation. It is calculated by dividing (a) total MWh generated by our power plants, excluding peakers, by (b) the product of multiplying (i) the average total MW in operation, excluding peakers, during the period by (ii) the total hours in the period
Bankruptcy Code	U.S. Bankruptcy Code
Bcf	Billion cubic feet
Broad River	Broad River Energy LLC, formerly an indirect, wholly-owned subsidiary of Calpine that leased the Broad River Energy Center, an 847 MW natural gas-fired, peaking power plant located in Gaffney, South Carolina
Btu	British thermal unit(s), a measure of heat content
CAA	Federal Clean Air Act, U.S. Code Title 42, Chapter 85
CAIR	Clean Air Interstate Rule
CAISO	California 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
CCFC Term Loans	Collectively, the $900 million first lien senior secured term loan and the $300 million first lien senior secured term loan entered into on May 3, 2013, between CCFC, as borrower, and Goldman Sachs Lending Partners, LLC, as administrative agent and as collateral agent, and the lenders party thereto
CDHI	Calpine Development Holdings, Inc., an indirect, wholly-owned subsidiary of Calpine
CES	Calpine Energy Services, L.P., an indirect, wholly-owned subsidiary of Calpine

ABBREVIATION	DEFINITION
CFTC	U.S. Commodities Futures Trading Commission
Chapter 11	Chapter 11 of the U.S. Bankruptcy Code
CO_2	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
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, and was amended on June 27, 2013, 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
Effective Date	January 31, 2008, the date on which the conditions precedent enumerated in the Plan of Reorganization were satisfied or waived and the Plan of Reorganization became effective

ABBREVIATION	DEFINITION
EIA	Energy Information Administration of the U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
Equity Plan	The Amended and Restated Calpine Corporation 2008 Equity Incentive Plan
ERCOT	Electric Reliability Council of Texas
EWG(s)	Exempt wholesale generator(s)
Exchange Act	U.S. Securities Exchange Act of 1934, as amended
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, the 2022 First Lien Notes, the 2023 First Lien Notes and the 2024 First Lien Notes
First Lien Term Loans	Collectively, the 2018 First Lien Term Loans, the 2019 First Lien Term Loan and the 2020 First Lien Term Loan
FRCC	Florida Reliability Coordinating Council
GE	General Electric International, Inc.
GEC	Collectively, Gilroy Energy Center, LLC, Creed and Goose Haven
Geysers Assets	Our geothermal power plant assets, including our steam extraction and gathering assets, located in northern California consisting of 15 operating power plants and one plant not in operation
GHG(s)	Greenhouse gas(es), primarily carbon dioxide (CO_2), and including methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs)
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

ABBREVIATION	DEFINITION
Hg	Mercury
IRC	Internal Revenue Code
IRS	U.S. Internal Revenue Service
ISO(s)	Independent System Operator(s)
KIAC	KIAC Partners, an indirect, wholly-owned subsidiary of Calpine that leases our Kennedy International Airport Power Plant, a 121 MW natural gas-fired, combined-cycle power plant located at John F. Kennedy International Airport in New York
KWh	Kilowatt hour(s), a measure of power produced, purchased or sold
LIBOR	London Inter-Bank Offered Rate
Los Esteros Project Debt	Credit Agreement dated August 23, 2011, between Los Esteros Critical Energy Facility, LLC, as borrower, and the lenders named therein
LTSA(s)	Long-Term Service Agreement(s)
Market Heat Rate(s)	The regional power price divided by the corresponding regional natural gas price
MISO	Midwest ISO
MMBtu	Million Btu
MRO	Midwest Reliability Organization
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
NDH	New Development Holdings, LLC, an indirect, wholly-owned subsidiary of Calpine
NDH Project Debt	The $1.3 billion senior secured term loan facility and the $100 million revolving credit facility issued on July 1, 2010, under the credit agreement, dated as of June 8, 2010, among NDH, as borrower, Credit Suisse AG, as administrative agent, collateral agent, issuing bank and syndication agent, Credit Suisse Securities (USA) LLC, Citigroup Global Markets Inc. and Deutsche Bank Securities Inc., as joint book-runners and joint lead arrangers, Credit Suisse AG, Citibank, N.A., and Deutsche Bank Trust Company Americas, as co-documentation agents and the lenders party thereto repaid on March 9, 2011
NERC	North American Electric Reliability Council
NOL(s)	Net operating loss(es)
NOx	Nitrogen oxides
NPCC	Northeast Power Coordinating Council
NYISO	New York ISO

ABBREVIATION	DEFINITION
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OMEC	Otay Mesa Energy Center, LLC, an indirect, wholly-owned subsidiary of Calpine that owns the Otay Mesa Energy Center, a 608 MW natural gas-fired, combined-cycle power plant located in San Diego county, California
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
Plan of Reorganization	Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code filed by the U.S. Debtors with the U.S. Bankruptcy Court on December 19, 2007, as amended, modified or supplemented
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)
Report	This Annual Report on Form 10-K for the year ended December 31, 2013, filed with the SEC on February 12, 2014
Reserve margin(s)	The measure of how much the total generating capacity installed in a region exceeds the peak demand for power in that region
RFC	Reliability *First* Corporation
RGGI	Regional Greenhouse Gas Initiative
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

ABBREVIATION	DEFINITION
RMR Contract(s)	Reliability Must Run contract(s)
RPS	Renewable Portfolio Standards
RTO(s)	Regional Transmission Organization(s)
Russell City Project Debt	Credit Agreement dated June 24, 2011, between Russell City Energy Company, LLC, as borrower, and the lenders named therein
SEC	U.S. Securities and Exchange Commission
Securities Act	U.S. Securities Act of 1933, as amended
SERC	Southeastern Electric Reliability Council
SO_2	Sulfur dioxide
Spark Spread(s)	The difference between the sales price of power per MWh and the cost of fuel to produce it
SPP	Southwest Power Pool
Steam Adjusted Heat Rate	The adjusted Heat Rate for our natural gas-fired power plants, excluding peakers, calculated by dividing (a) the fuel consumed in Btu reduced by the net equivalent Btu in steam exported to a third party by (b) the KWh generated. Steam Adjusted Heat Rate is a measure of fuel efficiency, so the lower our Steam Adjusted Heat Rate, the lower our cost of generation
TCEQ	Texas Commission on Environmental Quality
TRE	Texas Reliability Entity, Inc.
TSR	Total shareholder return
U.S. Bankruptcy Court	U.S. Bankruptcy Court for the Southern District of New York
U.S. Debtor(s)	Calpine Corporation and each of its subsidiaries and affiliates that filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court, which matter was jointly administered in the U.S. Bankruptcy Court under the caption *In re Calpine Corporation, et al.*, Case No. 05-60200 (BRL) and was dismissed on December 19, 2011
U.S. GAAP	Generally accepted accounting principles in the U.S.
VAR	Value-at-risk
VIE(s)	Variable interest entity(ies)
WECC	Western Electricity Coordinating Council
Whitby	Whitby Cogeneration Limited Partnership, a 50% 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
WP&L	Wisconsin Power & Light Company

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,” “should,” “estimate,” “potential,” “project” and similar expressions to identify forward-looking statements. Such statements include, among others, those concerning our expected financial performance and strategic and operational plans, as well as all assumptions, expectations, predictions, intentions or beliefs about future events. You are cautioned that any such forward-looking statements are not guarantees of future performance and that a number of risks and uncertainties could cause actual results to differ materially from those anticipated in the forward-looking statements. Such risks and uncertainties include, but are not limited to:

- Financial results that may be volatile and may not reflect historical trends due to, among other things, seasonality of demand, 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 Term Loans 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;
- Structural changes in the supply and demand of power, resulting from the development of new fuels or technologies and demand-side management tools;
- 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.

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

Where You Can Find Other Information

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

PART I

Item 1. *Business*

BUSINESS AND STRATEGY

Business

We are a premier wholesale power producer with operations throughout the U.S. We measure our success by delivering long-term shareholder value. We accomplish this through our focus on operational excellence at our power plants and in our commercial activity and on a disciplined approach to capital allocation that includes investing in growth, returning money to shareholders through share repurchases, and prudent balance sheet management.

We are one of the largest 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. Since our inception in 1984, we have been a leader in environmental stewardship. We have invested in clean power generation to become a recognized leader in developing, constructing, owning and operating an environmentally responsible portfolio of power plants. Our portfolio is primarily comprised of two types of power generation technologies: natural gas-fired combustion turbines, which are primarily efficient combined-cycle plants, and renewable geothermal conventional steam turbines. We are among the world's largest owners and operators of industrial gas turbines as well as cogeneration power plants. Our Geysers Assets located in northern California represent the largest geothermal power generation portfolio in the U.S. and produced approximately 18% of all renewable energy in the state of California during 2012.

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 natural gas and fuel oil as fuel for our power plants and engage in related natural gas transportation and storage transactions. We also purchase electric transmission rights to deliver power to our customers. Additionally, consistent with our Risk Management Policy, we enter into natural gas and power physical and financial contracts to hedge certain business risks and optimize our portfolio of power plants.

Our portfolio, including partnership interests, consists of 93 power plants, including three under construction (one new power plant and two expansions of existing power plants), located throughout 20 states in the U.S. and Canada, with an aggregate generation capacity of 28,104 MW and 699 MW under construction. We have also announced the acquisition of a 1,050 MW power plant in Texas that is expected to close in the first quarter of 2014. Our fleet, including projects under construction, consists of 75 combustion turbine-based plants, two fossil steam-based plants, 15 geothermal turbine-based plants and one photovoltaic solar plant. In 2013, our fleet of power plants produced approximately 104 billion KWh of electric power for our customers. In addition, we are one of the largest consumers of natural gas in North America. In 2013, we consumed 782 Bcf or approximately 10% of the total estimated natural gas consumed for power generation in the U.S.

We believe our unique fleet compares favorably with those of our major competition on a cost basis, an environmental basis, and a scale and geographical diversity basis. The discovery and exploitation of shale natural gas combined with our modern and efficient combined-cycle plants has created short-term and long-term advantages. In the short-term, we are often the lowest cost resource to dispatch compared to other fuel types as demonstrated in 2012 and in 2013 when we realized meaningfully higher capacity factors than we have historically given our ability to displace other fuel types and older technologies. In the long-term, when compared on a full life-cycle cost, our power plants are even more competitive when considering the greater non-fuel operating costs and potential environmental liabilities associated with other technologies.

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

Our scale provides the opportunity to have meaningful regulatory input, an ability to leverage our procurement efforts for better pricing, terms and conditions on our goods and services, and to develop and offer a wide array of products and services to our customers. Finally, geographic diversity helps us manage and mitigate the impact of weather, regulatory and regional economic differences across our markets to provide more consistent financial performance.

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

Strategy

Our goal is to be recognized as the premier power generation company in the U.S. as measured by our employees, shareholders, customers and regulators as well as 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. Our strategy to achieve this is reflected in the four major initiatives described below:

1. *Focus on Remaining a Premier Operating Company* — Our objective is to be the “best-in-class” in regards to certain operational performance metrics, such as safety, availability, reliability, efficiency and cost management.
   - Our entire fleet achieved an exceptionally low forced outage factor of 1.6% and an impressive starting reliability of 98.5% during the year ended December 31, 2013.
   - Our 619 MW Russell City Energy Center (Calpine's 75% net interest is 464 MW) and 309 MW Los Esteros Critical Energy Facility commenced commercial operations during the third quarter of 2013 and achieved average capacity factors of 63.9% and 28.0%, respectively, after COD.
   - We commenced construction on the first phase of our Garrison Energy Center located in Dover, Delaware, during the second quarter of 2013 and expect COD during the second quarter of 2015.
   - For the past thirteen consecutive years, our Geysers Assets have reliably generated approximately 6 million MWh of renewable power per year and, in 2013, achieved an exceptional availability factor of approximately 96%.
2. *Focus on Enhancing Shareholder Value* — We continue to make significant progress to deliver financially disciplined growth, to enhance shareholder value through disciplined capital allocation and to set the foundation for future growth and success. Given our strong cash flow from operations, we are committed to remaining financially disciplined in our capital allocation decisions. The year ended December 31, 2013 was marked by the following accomplishments:
   - Having previously authorized $600 million in repurchases of our common stock, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock in February 2013 and an additional $100 million in August 2013. Under the aggregate $1.1 billion of authorizations, we repurchased a total of 60,139,816 shares of our outstanding common stock at an average price of $18.29 per share. In November 2013, our Board of Directors authorized a new $1.0 billion multi-year share repurchase program, under which we have repurchased a total of 12,459,919 shares of our common stock for approximately $239 million at an average price of $19.15 per share as of the filing of this Report.
   - In February 2013, we repriced our First Lien Term Loans by lowering the LIBOR floor by 0.25% to 1.0% and the margin over LIBOR by 0.25% to 3.0%.
   - On May 3, 2013, CCFC, our indirect, wholly-owned subsidiary, entered into a credit agreement providing for a first lien senior secured term loan facility comprised of (i) a $900 million 7-year term loan and (ii) a $300 million 8.5-year term loan. CCFC utilized the proceeds received from the CCFC Term Loans to redeem the CCFC Notes which converted $1.0 billion in fixed rate debt to lower variable rate debt and extended the maturity.
   - On June 27, 2013, we amended our Corporate Revolving Facility which lowered our costs and extended the maturity by more than two and half years.
   - On October 31, 2013, we issued our 2024 First Lien Notes and used the proceeds to reduce our overall cost of debt and extend maturities by redeeming a portion of our 2019 First Lien Notes, 2020 First Lien Notes, 2021 First Lien Notes and 2023 First Lien Notes each of which carry a higher fixed interest rate.
   - On December 2, 2013, we completed the repayment of our 2017 First Lien Notes with the proceeds from our 2020 First Lien Term Loan and 2022 First Lien Notes which will lower our annual interest expense and extend the maturity of approximately $1.1 billion in debt.

3. *Focus on Leveraging our Three Scale Regions* — Our goal is to continue to grow our generation presence in core markets with an emphasis on acquisitions, 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 offer proven and financially disciplined opportunities to improve our operations, capacity and efficiencies. Our significant projects under construction, growth initiatives and modernization activities are discussed below:

<u>West:</u>

- *Russell City Energy Center* — Our Russell City Energy Center commenced commercial operations in August 2013 which brought on line approximately 429 MW of net interest baseload capacity (464 MW with peaking capacity) representing our 75% share. 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 ten-year 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 has increased the efficiency and environmental performance of the power plant by lowering the Heat Rate. Our Los Esteros Critical Energy Facility commenced commercial operations in August 2013.

<u>Texas:</u>

- *Channel and Deer Park Expansions* — In the fourth quarter of 2012, we began construction to expand the baseload capacity of our Deer Park and Channel Energy Centers by approximately 260 MW each. Each power plant features an oversized steam turbine that, along with existing plant infrastructure, allows us to add capacity and improve the power plant's overall efficiency at a meaningful discount to the market cost of building new capacity. We expect COD on the expansions of our Channel and Deer Park Energy Centers during the second quarter of 2014.
- *Guadalupe Energy Center* — On December 2, 2013, we announced an agreement to purchase a natural gas-fired, combined-cycle power plant with a nameplate capacity of 1,050 MW located in Guadalupe County, Texas for approximately $625 million, which will increase capacity in our Texas segment. The purchase price does not include $15 million in consideration for the rights we also acquired to an advanced development opportunity for an approximately 400 MW quick-start, natural gas-fired peaker, if market conditions warrant. We are currently evaluating funding sources for the acquisition of this power plant including, but not limited to, nonrecourse financing, corporate financing or internally generated funds.

<u>North:</u>

- *Garrison Energy Center* — Garrison Energy Center is a 309 MW combined-cycle project located in Delaware on a site secured by a long-term lease with the City of Dover. Construction commenced in April 2013, and we expect COD during the second quarter of 2015. The project's capacity cleared PJM's 2015/2016 and 2016/2017 base residual auctions. We are currently evaluating funding sources for the construction of this project including, but not limited to, nonrecourse financing, corporate financing or internally generated funds. We are in the early stages of development of a second phase (309 MW) of this project. PJM has completed the feasibility and system impact studies for this phase and the facilities study is currently underway.
- *Mankato Power Plant Expansion* — We are proposing a 345 MW expansion of the Mankato Power Plant in response to a competitive resource acquisition process for approximately 500 MW of new capacity established by the Minnesota Public Utilities Commission ("MPUC"). The initial stage of the proceeding was managed via a contested case hearing. On December 31, 2013, the Administrative Law Judge ("ALJ") in the contested case issued a non-binding recommendation to the MPUC that the state should secure approximately 100 MW of distributed solar resources at this time and defer procurement of new thermal resources. Xcel Energy (Northern States Power) and the Minnesota Department of Commerce subsequently filed exceptions to the ALJ decision and continue to advocate in support of new, natural gas-fired generation resources. The MPUC will hold deliberations and decide whether to accept, reject or modify the ALJ recommendation in early 2014.
- *PJM Development Opportunities* — We are currently evaluating opportunities to develop more than 1,000 MW in the PJM market area that feature cost advantages such as existing infrastructure and favorable transmission queue

positions. These projects are continuing to advance entitlements (permits, zoning, transmission, etc.) for their potential development at a future date.

<u>All Segments:</u>

- *Turbine Modernization* — We continue to move forward with our turbine modernization program. Through December 31, 2013, we have completed the upgrade of twelve Siemens and eight GE turbines totaling approximately 200 MW and have committed to upgrade approximately four additional turbines. Similarly, we have the opportunity at several of our power plants in Texas to implement further turbine modernizations to add as much as 500 MW of incremental capacity across the region at attractive prices. In addition, we have begun a program to update our dual-fueled turbines at certain of our power plants in our North segment. Our decision to invest in these turbine modernizations depends upon, among other things, further clarity on market design reforms currently being considered.

4. *Focus on Customer-Oriented Origination Business* — We continue to focus on providing products and services that are beneficial to our customers. A summary of certain significant contracts entered into in 2013 is as follows:

   - We entered into a new three-year PPA with South Carolina Electric and Gas Company to provide 200 MW of power generated by our Columbia Energy Center, commencing in January 2014.
   - We entered into two new resource adequacy contracts with PG&E for our Delta and Sutter Energy Centers for the full capacity of each plant which commence in January and June 2014, respectively, and extend through December 2015 and 2016, respectively.
   - We entered into two new PPAs with the Marin Energy Authority consisting of a one-year contract to provide 3 MW of renewable power during 2014 and a ten-year contract to provide 10 MW of renewable power commencing in January 2017. The renewable power to be delivered under both contracts will be generated from our Geysers Assets.
   - We entered into a 100 MW financial PPA with a counterparty in PJM which commenced in November 2013 and extends through 2016.
   - We entered into a new five-year PPA commencing in 2014 for approximately 50 MW and extended the existing steam agreement for ten years beyond 2016 with Celanese Ltd for power and steam generated from our Clear Lake Power Plant.
   - We entered into a new ten-year PPA with the Sonoma Clean Power Authority to provide 10 MW of renewable power from our Geysers Assets commencing in May 2014. The capacity under contract will increase in increments each year, up to a maximum of 18 MW for years 2020 through 2023.

THE MARKET FOR POWER

Our Power Markets and Market Fundamentals

The power industry represents one of the largest industries in the U.S. and impacts nearly every aspect of our economy, with an estimated end-user market of approximately $369 billion in power sales in 2013 according to the EIA. Historically, vertically integrated power utilities with monopolies over franchised territories dominated the power generation industry in the U.S. Over the last 25 years, industry trends and regulatory initiatives, culminating with the deregulation trend of the late 1990's and early 2000's, provided opportunities for wholesale power producers to compete to provide power. Although different regions of the country have very different models and rules for competition, the markets in which we operate have some form of wholesale market competition. California (included in our West segment), Texas and the Mid-Atlantic (included in our North segment), which are the markets in which we have our largest presence, have emerged as among the most competitive wholesale power markets in the U.S. We also operate, to a lesser extent, in the competitive wholesale power markets in New York, the northeast and the midwest. In addition to our sales of electrical power and steam, we produce several ancillary products for sale to our customers.

- First, we are a wholesale provider of power to utilities, independent electric system operators, industrial or agricultural companies, retail power providers, municipalities, and power marketers. Our power sales occur in several different product categories including baseload (around the clock generation), intermediate (generation typically more expensive than baseload and utilized during higher demand periods to meet shifting demand needs), and peaking energy (most expensive variable cost and utilized during the highest demand periods), for which the latter is provided by some of our stand-alone peaking power plants/units and from our combined-cycle power plants by using technologies such as steam injection or duct firing additional burners in the heat recovery steam generators. Many of our units have operated more frequently as baseload units at times when low natural gas prices have driven their production costs below those of some competing coal-fired units, especially during the record low gas prices of 2012.

- Second, we provide capacity for sale to utilities, independent electric system operators, and retail power providers. In various markets, retail power providers (or independent electric system operators on their behalf) are required to demonstrate adequate resources to meet their power sales commitments. To meet this obligation, they procure a market product known as capacity from power plant owners or resellers. Most electricity market administrators have acknowledged that an energy only market does not provide sufficient revenues to enable existing merchant generators to recover all of their costs or to encourage the construction of new power plants. Capacity auctions have been implemented in the northeast, the Mid-Atlantic and some midwest regional markets to address this issue. California has a bilateral capacity program. Texas does not presently have a capacity market, nor a requirement for retailers to ensure adequate resources.

- Third, we sell RECs from our Geysers Assets in northern California, as well as from our small solar power plant in New Jersey. California has an RPS that requires load serving entities to have RECs for a certain percentage of their demand for the purpose of guaranteeing a certain level of renewable generation in the state or in neighboring areas. Because geothermal is a renewable source of energy, we receive a REC for each MWh we produce and are able to sell our RECs to load serving entities. New Jersey has a solar specific RPS which enables us to sell RECs from a 4 MW photovoltaic solar generation facility located in Vineland, New Jersey.

- Fourth, our cogeneration power plants produce steam in addition to electricity for sale to industrial customers for use in their manufacturing processes or heating, ventilation and air conditioning operations.

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

In addition to the five products above, we are buyers and sellers of emission allowances and credits, including those under California's AB 32 GHG reduction program, RGGI, the federal Acid Rain and CAIR programs and emission reduction credits under the federal Nonattainment New Source Review program.

Although all of the products mentioned above contribute to our financial performance and are the primary components of our Commodity Margin, the most important are our sale of wholesale power and capacity. We utilize long-term customer contracts for our power and steam sales where possible. For power and capacity that are not sold under customer contracts or longer-dated capacity auctions, we use our hedging program and sell power into shorter term wholesale markets throughout the regions in which we participate.

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

Reserve Margins

Reserve margin, a measure of excess generation capacity in a market, is a key indicator of the competitive conditions in the markets in which we operate. For example, a reserve margin of 15% indicates that supply is 115% of expected peak power demand under normal weather and power plant outage conditions. Holding other factors constant, lower reserve margins typically lead to higher power prices because the less efficient capacity in the region is needed more often to satisfy power demand or voluntary or involuntary load shedding measures are taken. Markets with tight demand and supply conditions often display price spikes, higher capacity prices and improved bilateral contracting opportunities. Typically, the market price impact of reserve margins, as well as other supply/demand factors, is reflected in the Market Heat Rate, calculated as the local market power price divided by the local natural gas price.

During the last decade, the supply and demand fundamentals in many regional markets have been negatively impacted by the combination of new generation coming on line and a general decline in weather normalized load growth rates due to the economic recession and energy efficiency measures. Although uncertainty exists and there are key regional differences at a macro level, continued economic recovery and thus, corresponding net load recovery, with the lack of broad new power plant investments and the retirement of older, uneconomic units in our key markets should lead to lower reserve margins and higher Market Heat Rates. Reserve margins by NERC regional assessment area for each of our segments are listed below:

	2013(1)
West:	
WECC	24.7%
Texas:	
TRE	12.9%
North:	
NPCC	20.1%
MISO	18.8%
PJM	29.3%
Southeast:	
SERC	30.3%
SPP	39.4%
FRCC	28.4%

(1) Data source is NERC weather-normalized estimates for 2013 published in May 2013.

In recent years and in some regional markets such as PJM, the ability of customers to curtail load or temporarily utilize onsite backup generation instead of grid-provided electricity, known as "demand response," has become a significant portion of "supply" and thus contributes to reserve margin estimates. While demand response reduces demand for centralized generation during peak times, it typically does so at a very high variable cost. To the extent demand response resources are treated like other sources of supply (e.g., their variable cost-based bids are allowed to affect the market clearing price for power), high resulting prices benefit lower-cost units like Calpine's. Further, in many cases demand response has acted to discourage new investment in competing centralized generation plants (for example, by winning capacity auctions instead of new units). This should eventually contribute to higher energy price volatility during peak energy demand periods.

The Price and Supply of Natural Gas

Approximately 95% of our generating capability's fuel requirements are met with natural gas. We have approximately 725 MW of baseload capacity from our Geysers Assets and our expectation is that the steam reservoir at our Geysers Assets will be able to supply economic quantities of steam for the foreseeable future as our steam flow decline rates have become very small over the past several years. We also have approximately 596 MW of capacity from power plants where we purchase fuel oil to meet these generation requirements, but generally do not expect fuel oil requirements to be material to our portfolio of power plants. In our North segment, where the supply of natural gas is constrained, we have approximately 5,500 MW of dual-fueled capable power plants. Additionally, we have 4 MW of capacity from solar power generation technology with no fuel requirement.

We procure natural gas from multiple suppliers and transportation and storage sources. Although availability is generally not an issue, localized shortages (especially in extreme weather conditions in and around population centers), transportation availability and supplier financial stability issues can and do occur. When natural gas supply interruptions do occur, some of our power plants benefit from the ability to operate on fuel oil instead of gas.

Lower natural gas prices over the past five years have had a significant impact on power markets. Beginning in 2009, there was a significant decrease in NYMEX Henry Hub natural gas prices from a range of $6/MMBtu — $13/MMBtu during 2008 to an average natural gas price of $4.03/MMBtu, $2.83/MMBtu, and $3.73/MMBtu during 2011, 2012 and 2013, respectively. Natural gas prices in some parts of the country for parts of 2011, 2012 and 2013 were low enough that modern, combined-cycle, natural gas-fired generation became less expensive on a marginal basis than coal-fired generation. The result was that natural gas displaced coal as a less expensive generation resource resulting in what the industry describes as coal-to-gas switching, the effects of which can be seen in our increased generation volumes, particularly in 2012.

The availability of non-conventional natural gas supplies, in particular shale natural gas, has been the primary driver of reduced natural gas prices in the last few years. Access to significant deposits of shale natural gas has altered the natural gas supply landscape in the U.S. and could have a longer-term and profound impact on both the outright price of natural gas and the historical regional natural gas price relationships (basis differentials). The U.S. Department of Energy estimates that shale natural gas production has the potential of 3 trillion to 4 trillion cubic feet per year and may be sustainable for decades with enough natural gas to supply the U.S. for the next 90 years. Despite moderate increases in natural gas prices and some significant, weather induced regional price spikes this winter, there is an emerging view that lower priced natural gas will be available for the medium to long-term future. Further, high levels of natural gas production relative to available pipeline export capacity in some locations such as the Marcellus shale production region have put additional, seasonal downward pressure on local natural gas prices. Overall, low natural gas prices and corresponding low power prices have challenged the economics of nuclear and coal-fired plants, leading to numerous announced and potential unit retirements.

The price of natural gas, economic growth and environmental regulations affect our Commodity Margin and liquidity. The impact of changes in natural gas prices differs according to the time horizon and regional market conditions and depends on our hedge levels and other factors discussed below.

Much of our generating capacity is located in California (included in our West segment), Texas and the Mid-Atlantic (included in our North segment) where natural gas-fired units set power prices during many hours. When natural gas is the price-setting fuel, increases in natural gas prices may increase our unhedged Commodity Margin because our combined-cycle power plants in those markets are more fuel-efficient than conventional natural gas-fired technologies and peaking power plants. Conversely, decreases in natural gas prices may decrease our unhedged Commodity Margin. In these instances, our cost of production advantage relative to less efficient natural gas-fired generation is diminished on an absolute basis. Additionally, in the Mid-Atlantic region, we have generating units capable of burning either natural gas or fuel oil. For these units, on the rare occasions when the price of natural gas is excessively high relative to fuel oil, our unhedged Commodity Margin may increase as a result of the lower cost fuel.

In 2012 and to a much lesser degree in 2013, given very low natural gas prices, natural gas-fired, combined-cycle units in many markets were frequently cheaper to dispatch than coal-fired power plants. When coal-fired electricity production costs exceed natural gas-fired production costs, coal-fired units tend to set power prices. In these hours, lower natural gas prices tend to increase our Commodity Margin, since our production costs fall while power prices remain constant (depending on our hedge levels and holding other factors constant).

Where we operate under long-term contracts, changes in natural gas prices can have a neutral impact on us in the short-term. This tends to be the case where we have entered into tolling agreements under which the customer provides the natural gas and we convert it to power for a fee, or where we enter into indexed-based agreements with a contractual Heat Rate at or near our actual Heat Rate for a monthly payment.

Changes in natural gas prices or power prices may also affect our liquidity. During periods of high or volatile natural gas prices, we could be required to post additional cash collateral or letters of credit.

Despite these short-term dynamics, over the long-term, we expect lower natural gas prices to encourage new combined-cycle gas turbine power plant investment, thus enhancing the competitiveness of our modern, natural gas-fired fleet by making investment in other technologies such as coal, nuclear or renewables less economic and, in fact, making it more challenging for existing generation resources that utilize such technology to continue operating economically.

Weather Patterns and Natural Events

Weather generally has a significant short-term impact on supply and demand for power and natural gas. Historically, demand for and the price of power is higher in the summer and winter seasons when temperatures are more extreme, and therefore, our unhedged revenues and Commodity Margin could be negatively impacted by relatively cool summers or mild winters. However, our geographically diverse portfolio mitigates the impact on our Commodity Margin of weather in specific regions of the U.S. Additionally, a disproportionate amount of our total revenue is usually realized during the summer months of our third fiscal quarter. We expect this trend to continue in the future as U.S. demand for power generally peaks during this time.

Operating Heat Rate and Availability

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

Regulatory and Environmental Trends

We believe that, on balance, we will be favorably impacted by current regulatory and environmental trends, including those described below, given the characteristics of our power plant portfolio:

- Economic pressures continue to increase for coal-fired power generation as state and federal agencies enact environmental regulations to reduce air emissions of certain pollutants such as SO_2, NO_X, GHG, Hg and acid gases, restrict the use of once-through cooling, and provide for stricter standards for managing coal combustion residuals. We anticipate that older, less efficient fossil-fuel power plants that emit much higher amounts of GHG, SO_2, NO_X, Hg and acid gases, which operate nationwide, but more prominently in the eastern U.S., will be negatively impacted by current and future air emissions, water and waste regulations and legislation both at the state and federal levels which will require many coal-fired power plants to install expensive air pollution controls or reduce or discontinue operations. As a result, any retirements or curtailments could enhance our growth opportunities. The estimated capacity for fossil-fueled plants older than 50 years and the total estimated capacity for fossil-fueled plants by NERC region are as follows:

	Generating Capacity Older Than 50 years	Total Generating Capacity
West:		
WECC	9,469 MW	133,348 MW
Texas:		
TRE	3,059 MW	82,920 MW
North:		
NPCC	7,286 MW	57,428 MW
MRO	4,736 MW	46,037 MW
RFC	25,234 MW	195,002 MW
Southeast:		
SERC	26,556 MW	232,000 MW
SPP	5,037 MW	60,093 MW
FRCC	279 MW	58,805 MW
Total	81,656 MW	865,633 MW

- An increase in power generated from renewable sources could lead to an increased need for flexible power that many of our power plants provide to protect the reliability of the grid and premium compensation for that flexibility; however, risks also exist that renewables have the ability to lower overall wholesale prices which could negatively impact us. Significant economic and reliability concerns for renewable generation have been raised, but we expect that renewable market penetration will continue to be assisted by state-level renewable portfolio standards and federal tax incentives. Should wind and solar generation continue to expand, our energy margin may decrease. To the extent market structures evolve to appropriately compensate units for providing flexible capacity to ensure reliability, our capacity revenues are likely to increase, providing an offset to reduced energy margin.
- The regulators in our core markets remain committed to the competitive wholesale power model, particularly in Texas and PJM where they continue to focus on market design and rules to assure the long-term viability of competition and the benefits to customers that justify competition.
- Utilities are increasingly focused on demand side management – managing the level and timing of power usage through load curtailment, dispatching generators located at commercial or industrial sites, and “smart grid” technologies that may improve the efficiencies, dispatch usage and reliability of electric grids. Scrutiny of demand side resources has increased in recent months as system operators evaluate their reliability (especially at high levels of penetration) and environmental authorities deal with the implications of relying on smaller, less environmentally efficient generation sources during periods of peak demand when air quality is already challenged.
- Environmental permitting requirements for new power plants, transmission lines and pipelines continue to increase in stringency and complexity, resulting in prolonged, expensive development cycles and high capital investments.

We believe these trends are overall positive for our existing fleet. For a discussion of federal, state and regional legislative and regulatory initiatives and how they might affect us, see “— Governmental and Regulatory Matters.”

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

- number of market participants, both in terms of physical presence as well as contribution toward financial market liquidity;
- amount of power available in the market;
- fluctuations in power supply due to planned and unplanned outages of generators;
- fluctuations in power demand due to weather and other factors;
- cost of fuel, which could be impacted by the efficiency of generation technology and fluctuations in fuel supply or interruptions in natural gas transportation;
- relative ease or difficulty of developing, permitting and constructing new power plants;
- availability and cost of power transmission;
- potential growth of demand side management;
- creditworthiness and other risks associated with counterparties;
- bidding behavior of market participants;
- regulatory and ISO guidelines and rules;
- structure of commercial products; and
- ability to optimize the market's mix of alternative sources of power such as renewable and hydroelectric power.

Competition

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

In markets with centralized ISOs, such as California, Texas and the Mid-Atlantic, our natural gas-fired power plants compete directly with all other sources of power. The EIA estimates that in 2013, 27% of the power generated in the U.S. was fueled by natural gas, 39% by coal, 19% by nuclear facilities and the remaining 15% of power generated by hydroelectric, fuel oil and other energy sources. We are subject to complex and stringent energy, environmental and other governmental laws and regulations at the federal, state and local levels in connection with the development, ownership and operation of our power plants. Federal and state legislative and regulatory actions continue to change. The federal government is continuing to take further action on many air pollutant emissions such as NO_X, SO_2, Hg and acid gases as well as on once-through cooling and coal ash disposal. Although we cannot predict the ultimate effect any future environmental legislation or regulations will have on our business, as a clean energy provider, we believe that we are well positioned for almost any increase in environmental rule stringency. We are actively participating in these debates at the federal, regional and state levels. For a further discussion of the environmental and other governmental regulations that affect us, see "— Governmental and Regulatory Matters."

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

Competition from other sources of power, such as nuclear energy and renewables, could increase in the future, but likely at a lower rate than had been previously expected. The nuclear incident in March 2011 at the Fukushima Daiichi nuclear power plant introduced substantial uncertainties around new nuclear power plant development in the U.S. Low power prices are even challenging the economics of existing nuclear facilities, resulting in the retirement or potential retirement of certain existing nuclear generating units.

Federal and state financial incentives and RPS requirements continue to foster renewables development. However, the production tax credit for wind expired at the end of 2013 (although if plants were "under construction", they could keep the credit) and for solar the investment tax credit expires at the end of 2016. Unless the tax credits are extended and/or natural gas prices increase substantially from today's levels, competition from new renewables will likely diminish. Beyond economic issues, there are concerns over the reliability and adequacy of transmission infrastructure to transmit certain renewable generation from its source to where it is needed. Consequently, long-term, natural gas units are likely still needed as baseload and "back-up" generation.

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

- provide affordable, reliable services to our customers;
- maintain excellence in operations;
- achieve and maintain a lower cost of production, primarily by maintaining unit availability, efficiency and production cost management;
- accurately assess and effectively manage our risks; and
- accomplish all of the above with an environmental impact lower than the competition, and further decreasing over time.

MARKETING, HEDGING AND OPTIMIZATION ACTIVITIES

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. Additionally, we seek strong bilateral relationships with load serving entities that can benefit us and our customers.

The majority of our risk exposures arise from our ownership and operation of power plants. Our primary risk exposures are Spark Spread, power prices, natural gas prices, capacity prices, locational price differences in power and in natural gas, natural gas transportation, electric transmission, REC prices, carbon allowance prices in California and other emissions credit prices. In addition to the direct risk exposure to commodity prices, we also have general market risks such as risk related to performance of our counterparties and customers and plant operating performance risk. We also have a small exposure to Canadian exchange rates due to our partial ownership of Greenfield LP and Whitby located in Canada, which are under long term contracts, and minimal fuel oil exposure which are not currently material to our operations. As such, we have currently elected not to hedge our Canadian exchange rate or fuel oil exposure.

We produced approximately 104 billion KWh of electricity in 2013 across North America (primarily in the U.S.). We are one of the largest consumers of natural gas in North America having consumed approximately 782 Bcf during 2013. The four primary power markets in which we conduct our operations are Texas, California, PJM and the Southeast. The Texas, California and PJM markets have a centralized market for which power demand and prices are determined on a spot basis (day ahead and real time), and the Southeast market is a bilateral market. Most of the power generated by our power plants is sold to entities such as independent electric system operators, utilities, municipalities and cooperatives, as well as to retail power providers, commercial and industrial end users, financial institutions, power trading and marketing companies and other third parties.

We 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 utilize these instruments to maximize the risk-adjusted returns for our Commodity Margin.

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 2014 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 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 estimates 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. 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. For control purposes, we have VAR limits that govern the overall risk of our portfolio of power plants, energy contracts, financial hedging transactions and other contracts. Our VAR limits, transaction approval limits and other risk related controls, are dictated by our Risk Management Policy which is approved by our Board of Directors and by a committee comprised of members of our senior management and administered by our Chief Risk Officer's organization. The Chief Risk Officer's organization is segregated from the commercial operations unit and reports directly to our

Audit Committee and Chief Financial Officer. Our Risk Management Policy is primarily designed to provide us with a degree of protection from significant downside commodity price risk exposure to our cash flows.

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 Statements of Operations and could create 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.

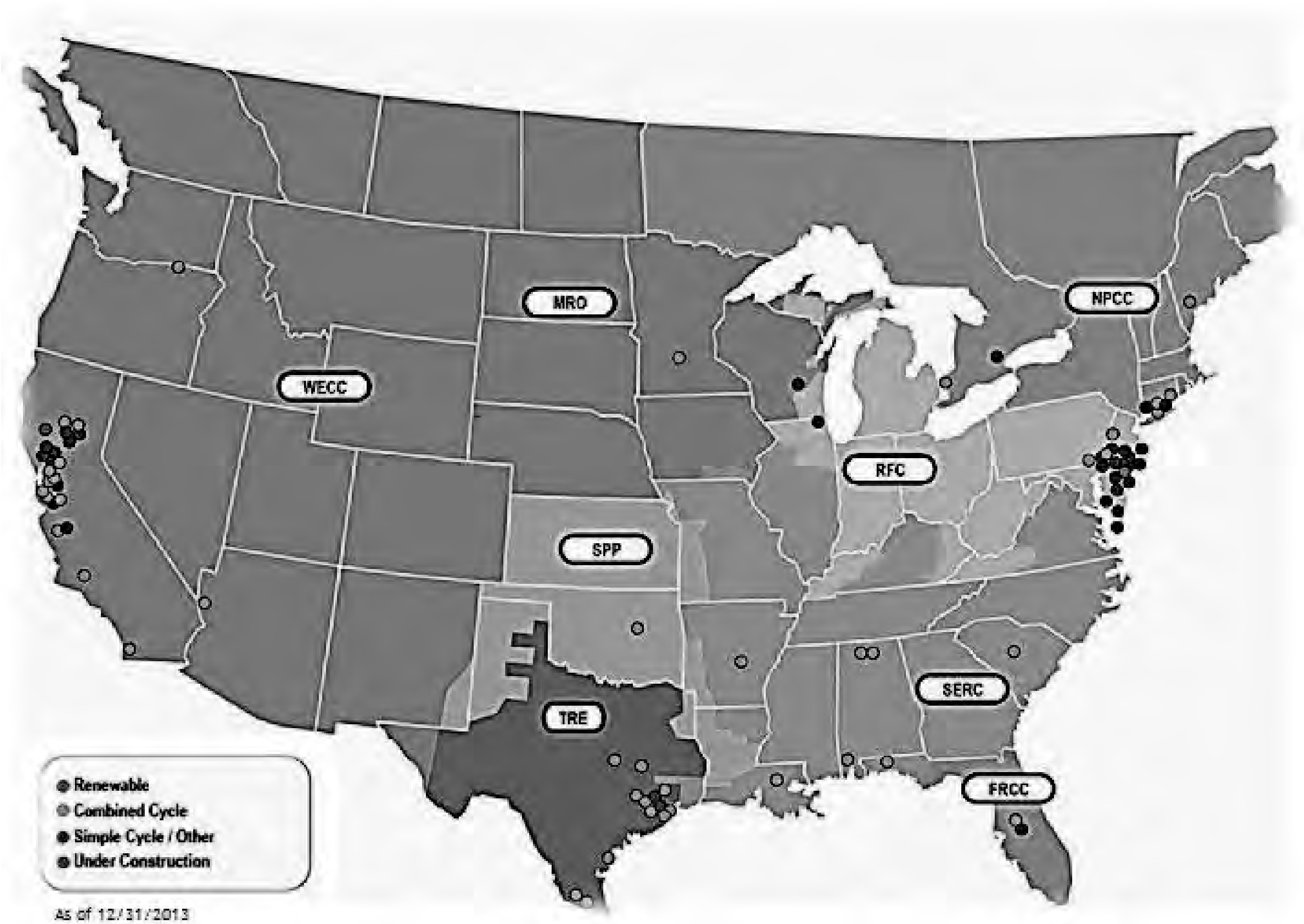
We have historically used interest rate swaps to adjust the mix between our fixed and variable rate debt. To the extent eligible, our interest rate swaps have been designated as cash flow hedges, and changes in fair value are recorded in OCI to the extent they are effective with gains and losses reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The reclassification of unrealized losses from AOCI into earnings and the changes in fair value and settlements subsequent to the reclassification date of the interest rate swaps formerly hedging our First Lien Credit Facility is presented separately from interest expense as loss on interest rate derivatives on our Consolidated Statements of Operations. See Note 8 of the Notes to Consolidated Financial Statements for further discussion of our derivative instruments.

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

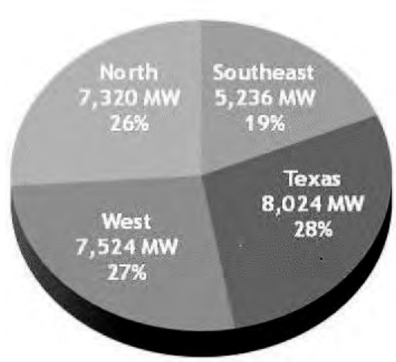
SEGMENT AND SIGNIFICANT CUSTOMER INFORMATION

See Note 16 of the Notes to Consolidated Financial Statements for a discussion of financial information by reportable segment and sales in excess of 10% of our annual consolidated revenues to two of our customers.

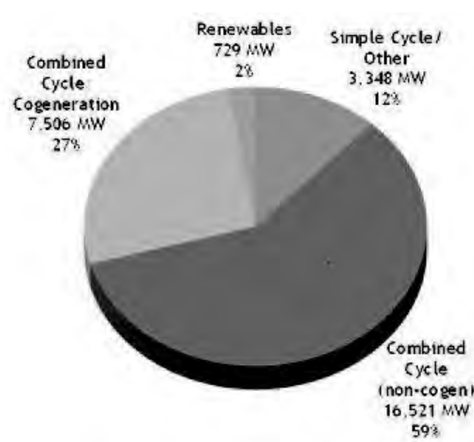
DESCRIPTION OF OUR POWER PLANTS



Geographic Diversity



Dispatch Technology



Power Plants in Operation at December 31, 2013

We own 93 power plants, including three under construction (one new power plant and two expansions of existing power plants), with an aggregate generation capacity of 28,104 MW and 699 MW under construction. We have also announced the acquisition of a 1,050 MW power plant in Texas that is expected to close in the first quarter of 2014.

Natural Gas-Fired Fleet

Our natural gas-fired power plants primarily utilize two types of designs: 2,465 MW of simple-cycle combustion turbines and 24,027 MW of combined-cycle combustion turbines and a small portion from conventional natural gas/oil-fired boilers with steam turbines. Simple-cycle combustion turbines burn natural gas or oil to spin an electric generator to produce power. A combined-cycle unit combusts fuel like a simple-cycle combustion turbine and the exhaust heat is captured by a heat recovery boiler to create steam which can then spin a steam turbine. Simple-cycle turbines are easier to maintain, but combined-cycle turbines operate with much higher efficiency. Each of our power plants currently in operation is capable of producing power for sale to a utility, another third-party end user or an intermediary such as a marketing company. At 19 of our power plants we also produce thermal energy (primarily steam and chilled water), which can be sold to industrial and governmental users. These plants are called combined heat and power facilities.

Our "all in" Steam Adjusted Heat Rate for 2013 for the power plants we operate was 7,386 Btu/KWh which results in a power conversion efficiency of approximately 46%. The power conversion efficiency is a measure of how efficiently a fossil fuel power plant converts thermal energy to electrical energy. Our "all in" Steam Adjusted Heat Rate includes all fuel required to dispatch our power plants including "start-up" and "shut-down" fuel, as well as all non-steady state operations. Once our power plants achieve steady state operations, our combined-cycle power plants achieve an average power conversion efficiency of approximately 50%. Additionally, we also sell steam from our combined heat and power plants, which improves our power conversion efficiency in steady state operations from these power plants to an average of approximately 53%. Due to our modern combustion turbine fleet, our power conversion efficiency is significantly better than that of older technology natural gas-fired power plants and coal-fired power plants, which typically have power conversion efficiencies that range from 28% to 36%.

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

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

Geothermal Fleet

Our Geysers Assets are a 725 MW fleet of 15 operating power plants in northern California. Geothermal power is considered a renewable energy because the steam harnessed to power our turbines is produced inside the Earth and does not require burning fuel. The steam is produced below the Earth's surface from reservoirs of hot water, both naturally occurring and injected. The steam is piped directly from the underground production wells to the power plants and used to spin turbines to make power. For the past thirteen consecutive years, our Geysers Assets have continued to generate approximately 6 million MWh of renewable power per year. Unlike other renewable resources such as wind or sunlight, which depend on intermittent sources to generate power, making them less reliable, geothermal power provides a consistent source of energy as evidenced by our Geysers Assets' availability record of approximately 96% in 2013.

We inject water back into the steam reservoir, which extends the useful life of the resource and helps to maintain the output of our Geysers Assets. The water we inject comes from the condensate associated with the steam extracted to generate power, wells and creeks, as well as water purchase agreements for reclaimed water. We receive and inject an average of approximately 16 million gallons of reclaimed water per day into the geothermal steam reservoir at The Geysers where the water is naturally heated by the Earth, creating additional steam to fuel our Geysers Assets. Approximately 12 million gallons per day are received from the Santa Rosa Geysers Recharge Project, which we developed jointly with the City of Santa Rosa, and we receive, on average, approximately 4 million gallons a day from The Lake County Recharge Project from Lake County. As a result of these recharge projects, MWh production has been relatively constant. We expect that, as a result of the water injection program, the reservoir at our Geysers Assets will be able to supply economic quantities of steam for the foreseeable future.

We periodically review our geothermal studies to help us assess the economic life of our geothermal reserves. Our most recent geothermal reserve study was conducted in 2011. Our evaluation of our geothermal reserves, including our review of any applicable independent studies conducted, indicated that our Geysers Assets should continue to supply sufficient steam to generate positive cash flows at least through 2068. In reaching this conclusion, our evaluation, consistent with the due diligence study of 2011, assumes that defined “proved reserves” are those quantities of geothermal energy which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations.

We lease the geothermal steam fields from which we extract steam for our Geysers Assets. We have leasehold mineral interests in 108 leases comprising approximately 29,000 acres of federal, state and private geothermal resource lands in The Geysers region of northern California. Our leases cover one contiguous area of property that comprises approximately 45 square miles in the northwest corner of Sonoma County and southeast corner of Lake County. The approximate breakout by volume of steam removed under the above leases for the year ended 2013 is:

- 29% related to leases with the federal government via the Office of Natural Resources Revenue (formerly, the Minerals Management Service),
- 28% related to leases with the California State Lands Commission, and
- 43% related to leases with private landowners/leaseholders.

In general, our geothermal leases grant us the exclusive right to drill for, produce and sell geothermal resources from these properties and the right to use the surface for all related purposes. Each lease requires the payment of annual rent until commercial quantities of geothermal resources are established. After such time, the leases require the payment of minimum advance royalties or other payments until production commences, at which time production royalties are payable on a monthly basis from 10 to 31 days (depending upon the lease terms) following the close of the production month. Such royalties and other payments are payable to landowners, state and federal agencies and others, and vary widely as to the particular lease. In general, royalties payable are calculated based upon a percentage of total gross revenue received by us associated with our geothermal leases. Each lease’s royalty calculation is based upon its percentage of revenue as calculated by its steam generated relative to the total steam generated by our Geysers Assets as a whole.

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

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

Other Power Generation Technologies

Across the fleet, we also have a variety of older, less efficient technologies including approximately 883 MW of capacity from power plants which have conventional steam turbine technology. We also have approximately 4 MW of capacity from solar power generation technology at our Vineland Solar Energy Center in New Jersey.

Table of Operating Power Plants and Projects Under Construction

Set forth below is certain information regarding our operating power plants and projects under construction at December 31, 2013.

SEGMENT / Power Plant	NERC Region	U.S. State or Canadian Province	Technology	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)(1)(3)	Calpine Net Interest With Peaking (MW)(2)(3)	2013 Total MWh Generated(4)
WEST							
Geothermal							
McCabe #5 & #6	WECC	CA	Renewable	100%	78	78	640,071
Ridge Line #7 & #8	WECC	CA	Renewable	100%	69	69	670,778
Calistoga	WECC	CA	Renewable	100%	66	66	470,897
Eagle Rock	WECC	CA	Renewable	100%	66	66	565,293
Quicksilver	WECC	CA	Renewable	100%	53	53	381,149
Cobb Creek	WECC	CA	Renewable	100%	52	52	428,533
Lake View	WECC	CA	Renewable	100%	52	52	506,450
Sulphur Springs	WECC	CA	Renewable	100%	51	51	448,878
Socrates	WECC	CA	Renewable	100%	50	50	374,884
Big Geysers	WECC	CA	Renewable	100%	48	48	439,554
Grant	WECC	CA	Renewable	100%	43	43	329,350
Sonoma	WECC	CA	Renewable	100%	42	42	332,408
West Ford Flat	WECC	CA	Renewable	100%	24	24	207,479
Aidlin	WECC	CA	Renewable	100%	17	17	112,149
Bear Canyon (5)	WECC	CA	Renewable	100%	14	14	94,787
Natural Gas-Fired							
Delta Energy Center	WECC	CA	Combined Cycle	100%	835	857	5,652,554
Pastoria Energy Center	WECC	CA	Combined Cycle	100%	770	749	4,998,564
Hermiston Power Project	WECC	OR	Combined Cycle	100%	566	635	3,655,669
Otay Mesa Energy Center	WECC	CA	Combined Cycle	100%	513	608	3,702,500
Metcalf Energy Center	WECC	CA	Combined Cycle	100%	564	605	3,196,876
Sutter Energy Center	WECC	CA	Combined Cycle	100%	542	578	1,042,367
Los Medanos Energy Center	WECC	CA	Cogen	100%	518	572	3,524,373
South Point Energy Center	WECC	AZ	Combined Cycle	100%	520	530	1,939,129
Russell City Energy Center	WECC	CA	Combined Cycle	75%	429	464	1,038,642
Los Esteros Critical Energy Facility	WECC	CA	Combined Cycle	100%	243	309	300,600
Gilroy Energy Center	WECC	CA	Simple Cycle	100%	—	141	63,072
Gilroy Cogeneration Plant	WECC	CA	Cogen	100%	109	130	126,272
King City Cogeneration Plant	WECC	CA	Cogen	100%	120	120	409,944
Greenleaf 1 Power Plant	WECC	CA	Combined Cycle	100%	50	50	21,634
Greenleaf 2 Power Plant	WECC	CA	Cogen	100%	49	49	264,182
Wolfskill Energy Center	WECC	CA	Simple Cycle	100%	—	48	19,023
Yuba City Energy Center	WECC	CA	Simple Cycle	100%	—	47	37,185
Feather River Energy Center	WECC	CA	Simple Cycle	100%	—	47	32,355
Creed Energy Center	WECC	CA	Simple Cycle	100%	—	47	12,688
Lambie Energy Center	WECC	CA	Simple Cycle	100%	—	47	11,526
Goose Haven Energy Center	WECC	CA	Simple Cycle	100%	—	47	12,253
Riverview Energy Center	WECC	CA	Simple Cycle	100%	—	47	20,288
King City Peaking Energy Center	WECC	CA	Simple Cycle	100%	—	44	6,453
Agnews Power Plant	WECC	CA	Combined Cycle	100%	28	28	19,489
Subtotal					6,581	7,524	36,110,298

SEGMENT / Power Plant	NERC Region	U.S. State or Canadian Province	Technology	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)(1)(3)	Calpine Net Interest With Peaking (MW)(2)(3)	2013 Total MWh Generated(4)
TEXAS							
Deer Park Energy Center	TRE	TX	Cogen	100%	843	1,014	5,526,362
Baytown Energy Center	TRE	TX	Cogen	100%	782	842	3,411,055
Pasadena Power Plant(6)	TRE	TX	Cogen/ Combined Cycle	100%	763	781	3,995,967
Bosque Energy Center	TRE	TX	Combined Cycle	100%	740	762	3,733,111
Freestone Energy Center	TRE	TX	Combined Cycle	75%	779	746	2,988,092
Magic Valley Generating Station	TRE	TX	Combined Cycle	100%	672	702	3,548,653
Channel Energy Center	TRE	TX	Cogen	100%	463	608	2,411,706
Brazos Valley Power Plant	TRE	TX	Combined Cycle	100%	520	606	2,651,755
Corpus Christi Energy Center	TRE	TX	Cogen	100%	426	500	1,996,448
Texas City Power Plant	TRE	TX	Cogen	100%	400	453	946,076
Clear Lake Power Plant	TRE	TX	Cogen	100%	344	400	419,127
Hidalgo Energy Center	TRE	TX	Combined Cycle	78.5%	392	374	1,714,807
Freeport Energy Center(7)	TRE	TX	Cogen	100%	210	236	1,253,892
Subtotal					7,334	8,024	34,597,051
NORTH							
Bethlehem Energy Center	RFC	PA	Combined Cycle	100%	1,037	1,130	4,863,858
Hay Road Energy Center	RFC	DE	Combined Cycle	100%	1,030	1,130	4,506,365
Edge Moor Energy Center	RFC	DE	Steam Cycle	100%	—	725	400,052
York Energy Center	RFC	PA	Combined Cycle	100%	519	565	2,018,753
Westbrook Energy Center	NPCC	ME	Combined Cycle	100%	552	552	2,372,882
Greenfield Energy Centre(8)	NPCC	ON	Combined Cycle	50%	422	519	846,921
RockGen Energy Center	MRO	WI	Simple Cycle	100%	—	503	172,430
Zion Energy Center	RFC	IL	Simple Cycle	100%	—	503	116,809
Mankato Power Plant	MRO	MN	Combined Cycle	100%	280	375	597,842
Cumberland Energy Center	RFC	NJ	Simple Cycle	100%	—	191	80,206
Deepwater Energy Center(9)	RFC	NJ	Steam Cycle	100%	—	158	35,444
Kennedy International Airport Power Plant	NPCC	NY	Cogen	100%	110	121	636,503
Sherman Avenue Energy Center	RFC	NJ	Simple Cycle	100%	—	92	23,550
Bethpage Energy Center 3	NPCC	NY	Combined Cycle	100%	60	80	221,689
Middle Energy Center(10)	RFC	NJ	Simple Cycle	100%	—	77	599
Carll's Corner Energy Center	RFC	NJ	Simple Cycle	100%	—	73	21,204
Cedar Energy Center(10)	RFC	NJ	Simple Cycle	100%	—	68	9,456
Mickleton Energy Center	RFC	NJ	Simple Cycle	100%	—	67	6,538
Missouri Avenue Energy Center(10)	RFC	NJ	Simple Cycle	100%	—	60	1,283
Bethpage Power Plant	NPCC	NY	Combined Cycle	100%	55	56	256,496
Christiana Energy Center	RFC	DE	Simple Cycle	100%	—	53	56
Bethpage Peaker	NPCC	NY	Simple Cycle	100%	—	48	154,107
Stony Brook Power Plant	NPCC	NY	Cogen	100%	45	47	313,139
Tasley Energy Center	RFC	VA	Simple Cycle	100%	—	33	308
Whitby Cogeneration(11)	NPCC	ON	Cogen	50%	25	25	202,322
Delaware City Energy Center	RFC	DE	Simple Cycle	100%	—	23	173
West Energy Center	RFC	DE	Simple Cycle	100%	—	20	161
Bayview Energy Center	RFC	VA	Simple Cycle	100%	—	12	682
Crisfield Energy Center	RFC	MD	Simple Cycle	100%	—	10	559
Vineland Solar Energy Center	RFC	NJ	Renewable	100%	—	4	5,694
Subtotal					4,135	7,320	17,866,081

SEGMENT / Power Plant	NERC Region	U.S. State or Canadian Province	Technology	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)[1][3]	Calpine Net Interest With Peaking (MW)[2][3]	2013 Total MWh Generated[4]
SOUTHEAST							
Oneta Energy Center	SPP	OK	Combined Cycle	100%	980	1,134	2,303,798
Morgan Energy Center	SERC	AL	Cogen	100%	720	807	3,728,930
Decatur Energy Center	SERC	AL	Combined Cycle	100%	782	795	1,108,330
Columbia Energy Center	SERC	SC	Cogen	100%	455	606	695,189
Osprey Energy Center	FRCC	FL	Combined Cycle	100%	537	599	2,679,745
Carville Energy Center	SERC	LA	Cogen	100%	449	501	2,218,870
Hog Bayou Energy Center	SERC	AL	Combined Cycle	100%	235	237	733,987
Santa Rosa Energy Center	SERC	FL	Combined Cycle	100%	235	225	373,755
Pine Bluff Energy Center	SERC	AR	Cogen	100%	184	215	1,491,617
Auburndale Peaking Energy Center	FRCC	FL	Simple Cycle	100%	—	117	5,959
Subtotal					4,577	5,236	15,340,180
Total operating power plants	**92**				**22,627**	**28,104**	**103,913,610**
Projects Under Construction							
Channel Energy Center Expansion	TRE	TX	Cogen	100%	260	200	n/a
Deer Park Energy Center Expansion	TRE	TX	Cogen	100%	260	190	n/a
Garrison Energy Center	RFC	DE	Combined Cycle	100%	273	309	n/a
Total operating power plants and projects					**23,420**	**28,803**	

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

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

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

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

(5) Bear Canyon will be retired in December 2014; however, the steam used to run its turbine will be redirected to a different Geysers power plant resulting in no diminution of overall generating capacity at our Geysers fleet.

(6) Pasadena is comprised of 260 MW of cogen technology and 521 MW of combined cycle (non-cogen) technology.

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

(8) Calpine holds a 50% partnership interest in Greenfield LP through its subsidiaries; however, it is operated by a third party.

(9) Deepwater Energy Center is currently scheduled to be retired in May 2014.

(10) We have provided notice to PJM that we plan to retire these units before commencement of the PJM Reliability Pricing Model 2015/2016 delivery year.

(11) Calpine holds a 50% partnership interest in Whitby Cogeneration through its subsidiaries; however, it is operated by Atlantic Packaging Products Ltd.

We provide operations and maintenance services for all but three of the power plants in which we have an interest. Such services include the operation of power plants, geothermal steam fields, wells and well pumps and natural gas pipelines. We also supervise maintenance, materials purchasing and inventory control, manage cash flow, train staff and prepare operations and maintenance manuals for each power plant that we operate. As a power plant develops an operating history, we analyze its operation and may modify or upgrade equipment, or adjust operating procedures or maintenance measures to enhance the power plant's reliability or profitability. Although we do not operate the Freeport Energy Center, our outage services subsidiary performs all major maintenance services for this plant under a contract with The Dow Chemical Company through April 2032.

Certain power plants in which we have an interest have been financed primarily with project financing that is structured to be serviced out of the cash flows derived from the sale of power (and, if applicable, thermal energy and capacity) produced by such power plants and generally provide that the obligations to pay interest and principal on the loans are secured solely by the capital stock or partnership interests, physical assets, contracts and/or cash flows attributable to the entities that own the power plants. The lenders under these project financings generally have no recourse for repayment against us or any of our assets or the assets of any other entity other than foreclosure on pledges of stock or partnership interests and the assets attributable to the entities that own the power plants. However, defaults under some project financings may result in cross-defaults to certain of our other debt and debt instruments, including our First Lien Notes, First Lien Term Loans and Corporate Revolving Facility. Acceleration of the maturity of a project financing following a default may also result in a cross-acceleration of such other debt.

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

EMISSIONS AND OUR ENVIRONMENTAL PROFILE

Our environmental record has been widely recognized. We were an EPA Climate Leaders Partner with a stated goal to reduce GHG emissions, and we became the first power producer to earn the distinction of Climate Action Leader™. We have certified our GHG emissions inventory with the California Climate Action Registry every year since 2003. In 2012, our emissions of GHG amounted to approximately 49 million tons.

Natural Gas-Fired Generation

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

	Air Pollutant Emission Rates — Pounds of Pollutant Emitted Per MWh of Power Generated		
Air Pollutants	**Average U.S. Coal-, Oil-, and Natural Gas-Fired Power Plant**(1)	**Calpine Natural Gas-Fired, Combined-Cycle Power Plant**(2)	**Advantage Compared to Average U.S. Coal-, Oil-, and Natural Gas-Fired Power Plant**
Nitrogen Oxides, NOx	4.16	0.12	97.1%
Acid rain, smog and fine particulate formation			
Sulfur Dioxide, SO_2	8.71	0.0043	99.9%
Acid rain and fine particulate formation			
Mercury Compounds(3)	0.00002	—	100%
Neurotoxin			
Carbon Dioxide, CO_2	1,941	852	56.1%
Principal GHG—contributor to climate change			

(1) The average U.S. coal-, oil- and natural gas-fired power plants' emission rates were obtained from the U.S. Department of Energy's Electric Power Annual Report for 2012. Emission rates are based on 2012 emissions and net generation. The U.S. Department of Energy has not yet released 2013 information.

(2) Our natural gas-fired, combined-cycle power plant estimated emission rates are based on our 2012 emissions and power generation data from our natural gas-fired, combined-cycle power plants (excluding combined heat power plants) as measured under the EPA reporting requirements.

(3) The U.S. coal-, oil- and natural gas-fired power plant air emissions of mercury compounds were obtained from the EPA Toxics Release Inventory for 2012. Emission rates are based on 2012 emissions and net generation from U.S. Department of Energy's Electric Power Annual Report for 2012.

Geothermal Generation

Our 725 MW fleet of geothermal turbine-based power plants utilizes a natural, renewable energy source, steam from the Earth's interior, to generate power. Since these power plants do not burn fossil fuel, they are able to produce power with negligible CO_2 (the principal GHG), NO_X and SO_2 emissions. Compared to the average U.S. coal-, oil- and natural gas-fired power plant, our Geysers Assets emit 99.9% less NO_X, 100% less SO_2 and 96.9% less CO_2. There are 18 active geothermal power plants located in The Geysers region of northern California. We own and operate 15 of them. We recognize the importance of our Geysers Assets and we are committed to extending and expanding this renewable geothermal resource through the addition of new steam wells and wastewater recharge projects where clean, reclaimed water from local municipalities is recycled into the geothermal resource where it is converted by the Earth's heat into steam for power production.

Water Conservation and Reclamation

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

- We receive and inject an average of approximately 16 million gallons of reclaimed water per day into the geothermal steam reservoir at The Geysers where the water is naturally heated by the Earth, creating additional steam to fuel our Geysers Assets. Approximately 12 million gallons per day are received from the Santa Rosa Geysers Recharge Project, which we developed jointly with the City of Santa Rosa, and we receive, on average, approximately 4 million gallons a day from The Lake County Recharge Project from Lake County.

- In our combined-cycle power plants, we use mechanical draft cooling towers, which use up to 90% less water than conventional once-through cooling systems. Two of our combined-cycle power plants employ air-cooled condensers, which consume virtually no water for cooling.

- In twelve of our operating power plants equipped with cooling towers, we reuse treated water from municipal treatment systems for cooling. By reusing water in these cooling towers, we avoid the usage of as much as 35 million gallons per day of valuable surface and/or groundwater for cooling.

- Russell City Energy Center was designed to operate on potable water initially until the recycled water facility allowing 100% reclaimed water to be used becomes fully operational. Initial performance of the recycled water facility has been insufficient to support plant operations on reclaimed water. As a result, Russell City Energy Center is continuing to use primarily potable water until such time as the recycled water facility achieves the desired performance. Calpine is in active discussions with regulatory agencies regarding this matter. We do not expect any material economic impact from the extended use of potable water.

GOVERNMENTAL AND REGULATORY MATTERS

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

Some of the more significant governmental and regulatory matters that affect our business are discussed below.

Environmental Matters

Federal Regulation of Air Emissions

The CAA provides for the regulation of air quality and air emissions, largely through state implementation of federal requirements. We believe that all of our operating power plants comply with existing federal and state performance standards mandated under the CAA. We continue to monitor and actively participate in EPA initiatives where we anticipate an impact on our business.

The CAA requires the EPA to regulate emissions of pollutants considered harmful to public health and the environment. The EPA has set NAAQS for six "criteria" pollutants: carbon monoxide, lead, NO_2, particulate matter, ozone and SO_2. In addition, the CAA regulates a large number of air pollutants that are known to cause or may reasonably be anticipated to cause adverse effects to human health or adverse environmental effects, known as hazardous air pollutants ("HAPs"). The EPA is required to issue technology-based national emissions standards for hazardous air pollutants ("NESHAPs") to limit the release of specified HAPs from specific industrial sectors.

Mercury and Air Toxics Standards

On December 21, 2011, the EPA issued the 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.

MATS has been extensively challenged through both administrative challenges and litigation, on issues relating to new units, existing units, and other technical issues. On April 24, 2013, the EPA finalized changes to the new unit standards in an attempt to resolve the administrative and judicial challenges relating to that particular section of the rule. Additional challenges, both administrative and legal, were filed with respect to that revision. Briefing has been submitted and oral argument concluded before the U.S. Court of Appeals for the D.C. Circuit ("D.C. Circuit"). We believe that a ruling will be issued by summer 2014. We are unable to predict the outcome of the various challenges to MATS.

CAIR and Multi-Pollutant Programs

Pursuant to authority granted under the CAA, the EPA promulgated the Clean Air Interstate Rule, or CAIR, regulations in March 2005, applicable to 28 eastern states and the District of Columbia, to facilitate attainment of its ozone and fine particulates NAAQS issued in 1997. CAIR's goal is to reduce SO_2 emissions in these states by over 70%, and NO_X emissions by over 60% from 2003 levels by 2015. CAIR established annual Cap-and-Trade programs for SO_2 and NO_X as well as a seasonal program for NO_X. On July 11, 2008, the D.C. Circuit invalidated CAIR. The court did not overturn the existing Cap-and-Trade program for SO_2 reductions under the Acid Rain Program or the existing ozone season Cap-and-Trade program under the NO_X State Implementation Plan Call. As a result of an EPA petition for rehearing, on December 23, 2008, the court left CAIR intact but remanded it to the EPA for further proceedings consistent with the July 11, 2008 opinion. As a result, CAIR went into effect on January 1, 2009, for many of our power plants located throughout the eastern and central U.S. Due to the low-emitting nature of our fleet, the net financial impact of this program to us is neutral to marginally positive.

Cross-State Air Pollution Rule

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR") as the replacement program for CAIR. CSAPR would require a total of 28 primarily eastern states, to reduce annual SO_2 emissions, annual NO_x emissions and/or ozone seasonal NO_x 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.

As with MATS, CSAPR was extensively challenged through both administrative and judicial processes. As a result of one of these challenges, on August 21, 2012, the D.C. Circuit vacated CSAPR, and ordered the EPA to continue administering CAIR. The U.S. Supreme Court heard the case on December 10, 2013 after granting *certiorari*. We cannot predict the outcome of this case. A decision is expected during summer of 2014. In the event that the D.C. Circuit decision is upheld, 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 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 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 to correspond to the effective date of the Tailpipe Rule. In the Tailoring Rule, the EPA departed from the CAA's 100/250 tpy emissions thresholds and provided that only sources with emissions exceeding 75,000 or 100,000 tpy carbon dioxide equivalent, depending on the program and project, would initially be subject to GHG permitting.

The EPA has issued guidance to permitting authorities on the implementation of GHG best available control technology ("BACT") that focuses on energy efficiency. Our Russell City Energy Center, a 619 MW combined-cycle power plant (our 75% net interest is 464 MW) in Hayward, California, voluntarily accepted GHG BACT limits in its PSD permit before such limits were required by law. Our Deer Park and Channel Energy Center expansions in Texas and our Garrison Energy Center in Delaware were all subject to PSD review for GHG emissions and were issued permits using unit efficiency as the basis for BACT. Based on this experience, for the foreseeable future, we expect that our efficient power plants will be found to meet BACT for GHGs where required to undergo PSD review. Accordingly, and taking into consideration the highly efficient nature of our fleet, we believe that the impact of EPA's GHG permitting rules will be neutral or marginally beneficial to us.

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 upheld all of the challenged GHG regulations. After D.C. Circuit appeals were denied, on October 15, 2013, the U.S. Supreme Court granted petitions for certiorari to review *Coalition for Responsible Regulation*, but only for consideration of one limited issue. Due to the narrowness of the question before the Court, this case does not appear to call into question the EPA's endangerment determination or the legal basis for regulating GHGs under the CAA, as confirmed by the Supreme Court in *Massachusetts v. EPA*. We expect that a ruling will be issued by summer 2014. We cannot predict the outcome of the Supreme Court's review or its implications on the EPA's GHG regulations or our operations at this time.

On June 25, 2013, President Obama announced a Climate Action Plan aimed at reducing GHG emissions in the U.S. to 17 percent below 2005 levels by 2020, and at the same time instructed the EPA to develop and implement (1) New Source Performance Standards ("NSPS") for GHG emissions from new electric generating units and (2) GHG emissions guidelines for existing power plants. In April 2012, the EPA had previously proposed a power sector NSPS of 1,000 lbs CO_2 per Megawatt-hour ("lb CO_2/MWh") for new fossil fuel-fired generating units, including boilers, integrated gasification combined-cycle units and stationary combined-cycle turbine units greater than 25 MW, irrespective of fuel type and generating technology. The President's memorandum directed the EPA to re-propose the new source rule by September 20, 2013. Next, the EPA is directed to propose a rule for modified, reconstructed and existing power plants by June 1, 2014. Finally, the EPA is directed to promulgate a final existing source rule no later than June 1, 2015. The memorandum also directs the EPA to require states to submit their implementation plans for the existing source role to the EPA by June 30, 2016.

On September 20, 2013, the EPA re-proposed the power sector GHG NSPS. The re-proposed rule, while similar to the original proposal in some respects, contains different emission standards for different generating technologies. Specifically, large combined-cycle turbines are subject to a standard of 1,000 lb CO_2/MWh, small combined-cycle turbines are subject to a standard of 1,050 lb CO_2/MWh, and traditional boiler-based power generation facilities are subject to a standard of 1,100 lb CO_2/MWh. The standards for combined-cycle turbines are based on the EPA's determination of what is achievable using natural gas combined-cycle technology. The standards for boiler-based units are based on the EPA's determination of what is achievable from new coal-fired utility steam generating units utilizing partial carbon capture and storage technology. The proposed standards effectively exempt most simple-cycle turbines operated as peaking units. We expect no negative impact on Calpine's fleet or development plans if the 2013 NSPS is finalized as proposed.

It is unclear what form the EPA's rule for regulating the GHG emissions from existing power plants will take. Accordingly, we cannot predict how the existing source rules for GHG emissions will regulate power plants and, thereby, the impact of this rule on Calpine is unknown. However, we believe that we operate one of the cleanest fleets of power plants in the U.S. and anticipate that we will be well positioned to comply with any such standards.

Demand Response Resources

On January 30, 2013, the EPA finalized amendments to the NESHAP for Reciprocating Internal Combustion Engines ("RICE"). The final rule creates an exemption from otherwise applicable air emission requirements for uncontrolled "emergency" diesel-fired backup generators to operate for up to 100 hours per year for "emergency demand response" and up to 50 hours per year in certain non-emergency situations as part of a financial arrangement with another entity.

On March 29, 2013, Calpine and PSEG Power LLC filed a petition for reconsideration with the EPA objecting to the final rule because it allows the increased use of uncontrolled, behind-the-meter diesel engines for the generation of electricity during periods of peak demand and, thereby, will cause an increase in ozone 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.

On June 28, 2013, the EPA granted partial reconsideration of the NESHAP for RICE, including the final rule's provisions allowing uncontrolled diesel engines to operate for up to 50 hours per year in non-emergency situations as part of a financial arrangement. Administrative and judicial challenges continue and we cannot predict the outcome of this litigation.

Fees on Permissible Emissions

Section 185 of the CAA requires major stationary sources of NO_X and volatile organic compounds ("VOCs"), such as power plants and refineries, in areas that fail to attain the NAAQS for ozone by the attainment date to pay a fee to the state or, if the state fails to collect the fee, the EPA. The fee is set in the CAA at $5,000 per ton of NO_X or VOC (adjusted for inflation or approximately $9,000 per ton in 2011) and is payable on emissions that exceed 80% of each individual power plant's baseline emissions, which are established in the year before the attainment date; however, the EPA has provided guidance for the calculation of alternative baselines. The fee will remain in effect until the designated area achieves attainment.

We operate seven power plants in Texas and one in California that are located within a designated nonattainment area subject to Section 185. The relevant agencies in both states issued regulations in 2012 and 2013 to address Section 185 fee collection. The EPA approval of the TCEQ regulation is pending. Our analysis of the final regulations indicates that we will have no fee obligation in either state.

Acid Rain Program

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

Regional and State Air Emissions Activities

Several states and regional organizations have developed state-specific or regional initiatives to reduce GHG emissions through mandatory programs. The most advanced programs include the RGGI in the northeast states and California's suite of GHG policies promulgated pursuant to AB 32, including its Cap-and-trade program. The evolution of these programs could have a material impact on our business.

In both of these programs, a cap is established defining the maximum allowable emissions of GHGs emitted by sources subject to the program. Affected sources are required to hold one allowance for each ton of CO_2 emitted (and, in the case of California's program, other GHGs) during the applicable compliance period. Both programs also contain provisions for the use of qualified offsets in lieu of allowances. Allowances are distributed through auctions or through allocations to affected companies. In addition, there are functional secondary markets for allowances. We obtain allowances in a variety of ways, including participation in auctions, as part of power purchase agreements, and through bilateral or exchange transactions.

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 and Mandatory Reporting Rule, 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 GHG emissions market is currently functioning and the cost of allowances is reflected in market pricing.

The California Cap-and-trade program has been challenged through administrative and judicial processes at both federal and state levels. Thus far, none of these challenges has been successful. 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 Cap-and-Trade Regulation or what the associated impacts of any such litigation would be.

On April 19, 2013, the CARB Board approved amendments to the Cap-and-Trade Regulation to link its program with Quebec's Cap-and-trade program starting January 1, 2014. While the linkage is currently effective, joint auctions of GHG allowances are not expected to occur until later 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%.

On September 4, 2013, the CARB proposed regulatory amendments to, among other things, provide allowances through 2017 to covered entities that have long-term contracts that do not allow the costs of compliance with the Cap-and-Trade Regulation to be passed through to their industrial host customers. If ultimately implemented in a form similar to the proposal, these amendments are expected to result in a modest benefit to us. The proposed amendments are likely to go into effect in late 2014.

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 the Cap-and-Trade Regulation.

Northeast and Mid-Atlantic States: CO_2 – RGGI

On January 1, 2009, ten northeast and Mid-Atlantic states implemented a Cap-and-trade program, RGGI, which affects our power plants in Maine, New York and Delaware (together emitting about 3.9 million tons of CO_2 annually). In 2011, New Jersey announced its withdrawal from the RGGI program effective as of the 2012 compliance year.

We receive annual allocations from New York's long-term contract set-aside pool to cover some of the CO_2 emissions attributable to our PPAs at both the Kennedy International Airport Power Plant and Stony Brook Power Plant. We do not anticipate any significant business or financial impact from RGGI, given the efficiency of our power plants in RGGI states.

Consistent with the original memorandum of understanding under which the states created RGGI, the overall success of the RGGI program was reviewed in 2012. This program review led to a number of changes, most significant of which was a reduction of the aggregate RGGI cap downward from 165 million tons to 91 million tons, slightly less than RGGI-wide emissions in 2012. We do not expect any material impact to our business from this change in regulations.

Texas: NO_X

Pursuant to authority granted under the CAA, regulations adopted by the TCEQ to attain the one-hour and eight-hour NAAQS for ozone included the establishment of a Cap-and-trade program for NO_X emitted by power plants in the Houston-Galveston-Brazoria ozone nonattainment area. We own and operate seven power plants that participate in this program, all of which received free NO_X allowances based on historical operating profiles. At this time, our Houston-area power plants have sufficient NO_X allowances to meet forecasted obligations under the program.

New Jersey: NO_X

New Jersey's High Electric Demand Day ("HEDD") Rule limits NOx emissions from turbines and boilers. Beginning in 2015, Phase 2 of the HEDD Rule will require investments in emissions controls on some of our peaking power plants. We have provided notice to PJM that we plan to retire our 158 MW Deepwater Energy Center before the commencement of the PJM 2014/2015 delivery year and our 68 MW Cedar Energy Center, 60 MW Missouri Avenue Energy Center, and 77 MW Middle Energy Center before the commencement of the PJM 2015/2016 delivery year. In the event certain transmission upgrades are not completed as planned, PJM may require one or more of the plants to continue to operate for a period of time, but we would be entitled to full cost recovery.

We plan to install emissions controls equipment at our 73 MW Carll's Corner Energy Center and 67 MW Mickleton Energy Center as these power plants cleared PJM's 2015/2016 base residual auction. All six of our power plants impacted by the HEDD Rule will be fully depreciated by June 2015. We expect that the retirement of these power plants or installation of emissions controls will not have a material impact on our financial condition, results of operations or cash flows.

Renewable Portfolio Standards

Policymakers have been considering variations of an RPS at the federal and state level. Generally, an RPS requires each retail seller of electricity to include in its resource portfolio (the resources procured by the retail seller to supply its retail customers) a certain amount of power generated from renewable or clean energy resources by a certain date.

Federal RPS

Although there is currently no national RPS, President Obama has stated his goal is to have 80% of the nation's electricity provided from clean energy resources, which includes natural gas resources, by 2035, and some U.S. Congressional members have expressed interest in national renewable or clean energy standard legislation. It is too early to determine whether or not the enactment of a national RPS will have a positive or negative impact on us. Depending on the RPS structure, an RPS could enhance the value of our existing Geysers Assets. However, an RPS would likely initially drive up the number of wind and solar resources, which could negatively impact the dispatch of our natural gas-fired power plants, primarily in Texas and California. Conversely, our natural gas power plants could benefit by providing complementary/back-up service for these intermittent renewable resources or by being included in a clean energy standard.

California 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 certain 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.

Other

A number of additional states have an RPS in place. Existing state-specific RPS requirements may change due to regulatory and/or legislative initiatives, and other states may consider implementing enforceable RPS in the future.

Other Environmental Regulations

In addition to controls on air emissions, our power plants and the equipment necessary to support them are subject to other extensive federal, state and local laws and regulations adopted for the protection of the environment and to regulate land use. The laws and regulations applicable to us primarily involve the discharge of wastewater and the use of water, but can also include wetlands protection and preservation, protection of endangered species, hazardous materials handling and disposal, waste disposal and noise regulations. Noncompliance with environmental laws and regulations can result in the imposition of civil or criminal fines or penalties. In some instances, environmental laws may also impose clean-up or other remedial obligations in the event of a release of pollutants or contaminants into the environment. The following federal laws are among the more significant environmental laws that apply to us. In most cases, analogous state laws also exist that may impose similar and, in some cases, more stringent requirements on us than those discussed below. In general, our relatively clean portfolio as compared to our competitors affords us some advantage in complying with these laws.

Clean Water Act and Cooling Water Intake Structure 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 spill prevention control and countermeasure plans for some of our power plants. We believe that we are in 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 under Section 316(b) 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 deadline for these final rules has been extended numerous times, and is currently in the process of being extended again until some time in 2014. 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 will be retired in May 2014.

Additionally, the EPA issued a proposed rule regarding effluent limitation guidelines and standards for the steam electric power generating point source category on June 7, 2013. The EPA is bound by a court-ordered consent decree to issue a final rule by May 22, 2014, although in January 2014, the EPA sought an extension to this deadline. 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"). The 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.

Safe Drinking Water Act

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

Resource Conservation and Recovery Act

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

On June 21, 2010, the EPA proposed a rule to regulate coal combustion residuals ("CCRs") under RCRA. A Notice of Data Availability ("NODA") was issued on October 12, 2011; but, there has not been any public movement on the rule since then. The EPA seeks to establish more stringent dam safety requirements to enhance performance surface impoundments used to manage CCRs. The EPA also seeks to regulate disposal of CCRs and has proposed to either regulate them as hazardous waste under Subtitle C of RCRA, or as nonhazardous waste under Subtitle D of RCRA. Both options will impose additional waste management costs on our competitors who rely on coal as a fuel. The EPA estimates a net present value cost of $3 billion to $21 billion to coal plants. We do not use coal so the CCRs rule, when finalized, will have no direct impact on our financial condition, results of operations or cash flows.

Comprehensive Environmental Response, Compensation and Liability Act

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

Federal Litigation regarding Liability for GHG Emissions

Litigation relating to common law tort liability for GHG emissions is working its way through the federal courts. While the U.S. Supreme Court has established that, in light of the EPA regulation of GHGs under the CAA, companies cannot be sued under federal common law theories of nuisance and negligence for their contribution to climate change, questions remain as to the viability of related state-law claims. In general, these state law-related claims have been unsuccessful in assigning tort liability for GHG emissions to power generators. We cannot predict the outcomes of these cases or what impact such cases, if successful, could have on our business.

Power and Natural Gas Matters

Federal Regulation of Power

FERC Jurisdiction

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

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

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

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

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

Pursuant to EPAct 2005, NERC has been certified by FERC as the Electric Reliability Organization to develop and oversee the enforcement of electric system reliability standards applicable throughout the U.S., which are subject to FERC review and approval. FERC-approved reliability standards may be enforced by FERC independently, or, alternatively, by NERC and the regional reliability organizations with frontline responsibility for auditing, investigating and otherwise ensuring compliance with reliability standards, subject to FERC oversight. Monetary penalties of up to $1 million per day per violation may be assessed for violations of the reliability standards.

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

Power Regions

The following is a brief overview of the most significant regulatory issues affecting our business in our three core markets — CAISO, ERCOT and PJM. The CAISO, ERCOT and PJM markets are in our West, Texas and North segments, respectively.

CAISO

The majority of our power plants in our West segment are located in California, in the CAISO region. We also own one power plant in Arizona and one in Oregon.

CAISO is responsible for ensuring the safe and reliable operation of the transmission grid within the bulk of California and providing open, nondiscriminatory transmission services. CAISO maintains various markets for wholesale sales of power, differentiated by time and type of electrical service, into which our subsidiaries may sell power from time to time. These markets are subject to various controls, such as price caps and mitigation of bids when transmission constraints arise. The controls and the markets themselves are subject to regulatory change at any time.

The CPUC and CAISO continue to evaluate capacity procurement policies and products for the California power market. With the expectation of significant increases in renewables, both entities are evaluating the need for operational flexibility attributes including the ability to start and ramp quickly as well as the ability to operate efficiently at low output levels or cycle off. We are an active participant in these discussions and support products and policies that would provide appropriate compensation for the required attributes. As these proceedings are ongoing, we cannot predict the ultimate impact on our financial condition, results of operations or cash flows, though we believe our fleet offers many features that can and do provide operational flexibility to the power markets.

ERCOT

ERCOT is the ISO that manages approximately 85% of Texas' load and an electric grid covering about 75% of the state, overseeing transactions associated with Texas' competitive wholesale and retail power markets. FERC does not regulate wholesale sales of power in ERCOT. The PUCT exercises regulatory jurisdiction over the rates and services of any electric utility conducting business within Texas. Our subsidiaries that own power plants in Texas have power generation company status at the PUCT, and are either EWGs or QFs and are exempt from PUCT rate regulation. ERCOT ensures resource adequacy through an energy-only model. In ERCOT, there is a market price cap for energy and capacity purchased by ERCOT. Under certain market conditions, the offer cap could be lower. Our subsidiaries are subject to the offer cap rules, but only for sales of power and capacity services to ERCOT.

The PUCT is considering changes regarding its approach to resource adequacy, including a centralized forward capacity market, but the timing of any major change remains uncertain. The need for change is prompted by uncertainty over whether sufficient generation will be available to reliably meet ERCOT's expected future demand growth, particularly during periods of high demand. The PUCT is attempting to address this issue with an increase in the system-wide offer cap to $7,000/MWh and implementing an operating reserve demand curve, which produces a price "adder" to the clearing price of energy. Both changes are effective on June 1, 2014. We support the development of a centralized forward capacity market to ensure ERCOT meets its reliability objective under almost any market conditions. As these proceedings are ongoing, we cannot predict the ultimate impact on our financial condition, results of operations or cash flows.

PJM

PJM operates wholesale power markets, a locationally based capacity market, a forward capacity market and ancillary service markets. PJM also performs transmission planning for the region. The rules and regulations affecting PJM power markets and transmission are subject to change at any time.

Certain states in the PJM market region, particularly New Jersey and Maryland, have taken anticompetitive actions that could have an adverse impact on the deregulated PJM power market by discouraging the construction of new generation. We are actively participating in the judicial process challenging these actions at the state and federal level. We believe the current competitive construct of the PJM power market whereby new construction of power generation facilities is determined by forward price signals and not ratepayer guaranteed rate recovery is the most efficient mechanism for incentivizing the construction of new power plants. As these judicial proceeding are ongoing, we cannot predict the ultimate impact on our financial condition, results of operations or cash flows.

PJM has submitted to the FERC for approval of new refinements to increase the effectiveness of the Reliability Pricing Model. We support these actions and believe that they generally enhance the competitiveness of the PJM power market; however, we cannot predict whether the FERC will approve these changes, what their ultimate impact may be, nor the impact on our financial condition, results of operations or cash flows.

Other State Regulation of Power

State Public Utility Commissions, or PUC(s), have historically had broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in their states and to promulgate regulation for implementation of PURPA. Since all of our affiliates are either QFs or EWGs, none of our affiliates are currently subject to direct rate regulation by a state PUC. However, states may assert jurisdiction over the siting and construction of power generating facilities including QFs and EWGs and, with the exception of QFs, over the issuance of securities and the sale or other transfer of assets by these facilities.

State PUCs also maintain extensive control over the procurement of wholesale power by the utilities that they regulate. Many of these utilities are our customers, and agreements between us and these counterparties often require approval by state PUCs.

Regulation of Transportation and Sale of Natural Gas

Since the majority of our power generating capacity is derived from natural gas-fired power plants, we are broadly impacted by federal regulation of natural gas transportation and sales. Furthermore, one of our natural gas transportation pipelines in Texas is subject to dual jurisdiction by the FERC and the Texas Railroad Commission. This pipeline is an intrastate pipeline within the meaning of Section 2(16) of the Natural Gas Policy Act ("NGPA"). FERC regulates the rates charged by this pipeline for transportation services performed under Section 311 of the NGPA, and the Texas Railroad Commission regulates the rates and services provided by this pipeline as a gas utility in Texas.

We also operate a proprietary pipeline system in California, which is regulated by the U.S. Department of Transportation and the Pipeline and Hazardous Materials Safety Administration with regard to safety matters. Additionally, some of our power plants own and operate short pipeline laterals that connect the natural gas-fired power plants to the North American natural gas grid. Some of these laterals are subject to state and/or federal safety regulations.

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

Federal Regulation of Futures and Other Derivatives

CFTC Regulation of Futures Transactions

The CFTC has regulatory oversight of the futures markets, including trading on NYMEX for energy, and licensed futures professionals such as brokers, clearing members and large traders. In connection with its oversight of the futures markets and NYMEX, the CFTC regularly investigates market irregularities and potential manipulation of those markets. Recent laws also give the CFTC certain powers with respect to broker-type markets referred to as "exempt commercial markets" or ECMs, including the Intercontinental Exchange. The CFTC monitors activities in the OTC, ECM and physical markets that may be undertaken for the purpose of influencing futures prices. With respect to ECMs, the CFTC exercises only light-handed regulation primarily related to trade reporting, price dissemination and record retention (including retention of fraudulent claims and allegations).

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

CFTC Regulation of Derivatives Transactions

The Dodd-Frank Act, which was signed into law on July 21, 2010, contains a variety of provisions designed to regulate financial markets, including credit and derivatives transactions. Title VII of the Dodd-Frank Act addresses regulatory reform of the OTC derivatives market in the U.S. and significantly changes the regulatory framework of this market. Certain Title VII regulations have been finalized and are effective though some regulations remain subject to a delayed compliance schedule. Other key regulations have not been finalized as of this time or remain in draft form. Until all of these regulations have been finalized, the extent to which the provisions of Title VII might affect our derivatives activities cannot be completely known.

While we are closely monitoring this rulemaking process from the CFTC (including related no-action relief, interpretations and orders), we have reviewed and assessed the impact of the CFTC's Title VII regulations on our business and related processes, and we have adjusted our internal procedures where necessary to comply with the applicable statutory law and related Title VII regulations which are effective at this time. We will continue to monitor all relevant developments and rulemaking initiatives, and we expect to successfully implement any new applicable requirements. At this time, we cannot predict the impact or possible additional costs to us related to the implementation of, or compliance with, the potential future requirements under the Dodd-Frank Act.

EMPLOYEES

At December 31, 2013, we employed 2,157 full-time employees, of whom 149 were represented by collective bargaining agreements, none of which expire within one year. We have never experienced a work stoppage or strike.

Item 1A. *Risk Factors*

Commercial Operations

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

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

- increases and decreases in generation capacity in our markets, including the addition of new supplies of power as a result of the development of new power plants, expansion of existing power plants or additional transmission capacity;
- changes in power transmission or fuel transportation capacity constraints or inefficiencies;
- power supply disruptions, including power plant outages and transmission disruptions;
- Heat Rate risk;
- weather conditions, particularly unusually mild summers or warm winters in our market areas;
- quarterly and seasonal fluctuations;
- changes in commodity prices and the supply of commodities, including but not limited to coal, natural gas and fuel oil;
- changes in the demand for power or in patterns of power usage, including the potential development of demand-side management tools and practices;
- development of new fuels or new technologies for the production or storage of power;
- federal and state regulations and actions of the ISOs;
- federal and state power, market and environmental regulation and legislation, including mandating an RPS or creating financial incentives, each resulting in new renewable energy generation capacity creating oversupply;
- changes in prices related to RECs; and
- changes in capacity prices and capacity markets.

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

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

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

- rate caps, price limitations and bidding rules imposed by ISOs, RTOs and other market regulators that may impair our ability to recover our costs and limit our return on our capital investments;
- regulations promulgated by the FERC and the CFTC;
- sufficient liquidity in the forward commodity markets to conduct our hedging activities;
- some of our competitors (mainly utilities) receive entitlement-guaranteed rates of return on their capital investments, with returns that exceed market returns and may impact our ability to sell our power at economical rates;
- structure and operating characteristics of our capacity markets such as our PJM capacity auctions and our NYISO markets; and

- regulations and market rules related to our RECs.

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

We engage in commodity-related marketing and price-risk management activities in order to economically hedge our exposure to market risk with respect to power sales from our power plants, fuel utilized by those assets and emission allowances. We generally attempt to balance our fixed-price physical and financial purchases, and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative contracts. These derivatives are accounted for under U.S. GAAP, which requires us to record all derivatives on the balance sheet at fair value unless they qualify for, and we elect, the normal purchase normal sale exemption. As a result, we are unable to accurately predict the impact that our risk management decisions may have on our quarterly and annual financial results.

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

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

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

Our ability to enter into hedging agreements and manage our counterparty credit risk could adversely affect us.

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

Competition could adversely affect our performance.

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

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

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

- the cessation or abandonment of the development, construction, maintenance or operation of a power plant;
- failure of a power plant to achieve construction milestones or commercial operation by agreed-upon deadlines;
- failure of a power plant to achieve certain output or efficiency minimums;
- our failure to make any of the payments owed to the counterparty or to establish, maintain, restore, extend the term of or increase any required collateral;
- failure of a power plant to obtain material permits and regulatory approvals by agreed-upon deadlines;

- a material breach of a representation or warranty or our failure to observe, comply with or perform any other material obligation under the contract; or
- events of liquidation, dissolution, insolvency or bankruptcy.

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

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

The introduction or expansion of competing technologies for power generation and demand-side management tools could adversely affect our performance.

The power generation business has seen a substantial change in the technologies used to produce power. With federal and state incentives for the development and production of renewable sources of power, we have seen market penetration of competing technologies, such as wind, solar, and commercial-sized power storage. Additionally, the development of demand-side management tools and practices can impact peak demand requirements for some of our markets at certain times during the year. The continued development of subsidized, competing power generation technologies and significant development of demand-side management tools and practices could alter the market and price structure for power and negatively impact our financial condition, results of operations and cash flows.

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

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

Power Operations

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

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

In addition, an unplanned outage may prevent the affected power plant from performing under any applicable PPAs, commodity contracts or other contractual arrangements. Such failure may allow a counterparty to terminate an agreement and/or seek liquidated damages, and we could incur costs to cover our hedges. Although insurance is maintained to partially protect against operating risks, the proceeds of insurance may not be adequate to cover lost revenues or increased expenses. As a result, we could be unable to service principal and interest payments under, or may otherwise breach, our financing obligations, particularly with respect to the affected power plant, which could result in losing our interest in the affected power plant or, possibly, one or more other power plants.

We may be subject to future claims, litigation and enforcement.

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

Additionally, we are party to various litigation matters, including regulatory and administrative proceedings arising out of the normal course of business. We review our litigation activities and determine if an unfavorable outcome to us is considered "remote," "reasonably possible" or "probable" as defined by U.S. GAAP. Where we have determined an unfavorable outcome is probable and is reasonably estimable, we accrue for potential litigation losses. A successful claim against us that is not fully insured could be material. 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. 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. See also Note 15 of the Notes to Consolidated Financial Statements for a description of our more significant litigation matters.

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

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

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

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

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

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

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

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

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

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

Our power plants and construction projects are subject to impairments.

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

Our geothermal power reserves may be inadequate for our operations.

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

- the heat content of the extractable steam or fluids;
- the geology of the reservoir;
- the total amount of recoverable reserves;
- operating expenses relating to the extraction of steam or fluids;

- price levels relating to the extraction of steam, fluids or power generated; and
- capital expenditure requirements relating primarily to the drilling of new wells.

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

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

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

We depend on our management and employees.

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

Some of our employees are represented by collective bargaining agreements.

We have 149 employees represented by collective bargaining agreements; however, the amount of employees subject to collective bargaining agreements only represents a small percentage (approximately 7%) of our employee base. In the event that our union employees participate in a strike, work stoppage or engage in other forms of labor disruption, we would be responsible for procuring replacement labor and could experience reduced power generation or outages.

We depend on computer and telecommunications systems we do not own or control and failures in our systems or cyber security attacks could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with the operation of our power plants. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. We also rely on software systems owned and operated by third parties such as ISOs and RTOs to be functioning in order to be able to transmit the electricity produced by our power plants to our customers. It is possible we or a third party that we rely on could incur interruptions from a loss of communications, hardware or software failures, cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties, to our computing and communications infrastructure, or our information systems or any of those operated by a third party that we rely on functioning could significantly disrupt our business operations.

Capital Resources; Liquidity

We have substantial liquidity needs and could face liquidity pressure.

As of December 31, 2013, our consolidated debt outstanding was $11.1 billion, of which approximately $7.8 billion was outstanding under our First Lien Notes and First Lien Term Loans. In addition, we had $630 million issued in letters of credit and our pro rata share of unconsolidated subsidiary debt was approximately $198 million. Although we significantly extended our maturities during the last four years, we could face liquidity challenges as we continue to have substantial debt and substantial liquidity needs in the operation of our business. Our ability to make payments on our indebtedness, to meet margin requirements and to fund planned capital expenditures and development efforts will depend on our ability to generate cash in the future from our operations and our ability to access the capital markets. This, to a certain extent, is dependent upon industry conditions, as well as general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control, as discussed further in "— Commercial Operations" above. Although we are permitted to enter into new project financing credit facilities to fund our development and construction activities, there can be no assurance that we will not face liquidity pressure in the future. See additional discussion regarding our capital resources and liquidity in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources.”

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

Our indebtedness has important consequences, including:

- limiting our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, potential growth or other purposes;
- limiting our ability to use operating cash flows in other areas of our business because we must dedicate a substantial portion of these funds to service our debt;
- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to capitalize on business opportunities and to react to competitive pressures and adverse changes in governmental regulation;
- limiting our ability or increasing the costs to refinance indebtedness or to repurchase equity issued by certain of our subsidiaries to third parties; and
- limiting our ability to enter into marketing, hedging and optimization activities by reducing the number of counterparties with whom we can transact as well as the volume and type of those transactions.

The soundness of financial institutions could adversely affect us.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Many of our collateral agreements require that letters of credit posted as collateral must be issued by a financial institution with a minimum credit rating of "A". Currently the financial institutions that issue letters of credit under our Corporate Revolving Facility and other letter of credit facilities meet or exceed the minimum credit rating criteria. However, if one or more of these financial institutions is no longer able to meet the minimum credit rating criteria, then we could be required to post collateral funding from our cash and cash equivalents which could negatively impact our liquidity.

Additionally, changes in market regulations can increase the use of credit support and collateral. The potential impact of the Dodd-Frank Act is uncertain, but it is possible that future regulations, when finalized, under the Dodd-Frank Act could directly or indirectly result in increased credit support and collateral requirements.

These letter of credit and cash collateral requirements increase our cost of doing business and could have an adverse impact on our overall liquidity, particularly if there was a call for a large amount of additional cash or letter of credit collateral due to an unexpectedly large movement in the market price of a commodity. As of December 31, 2013, we had $630 million issued in letters of credit under our Corporate Revolving Facility and other facilities, with $758 million remaining available for borrowing or for letter of credit support under our Corporate Revolving Facility. In addition, we have ratably secured our obligations under certain of our power and natural gas agreements that qualify as eligible commodity hedge agreements under our Corporate Revolving Facility with the assets previously subject to liens under our First Lien Credit Facility.

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

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

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

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

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

Almost all of our operations are conducted through our subsidiaries and other affiliates. As a result, we depend almost entirely upon their earnings and cash flows to service our indebtedness, post collateral and finance our ongoing operations. Certain of our project debt and other agreements restrict our ability to receive dividends and other distributions from our subsidiaries. Some of these limitations are subject to a number of significant exceptions (including exceptions permitting such restrictions in connection with certain subsidiary financings). Accordingly, the financing agreements of certain of our subsidiaries and other affiliates generally restrict their ability to pay dividends, make distributions or otherwise transfer funds to us prior to the payment of their other obligations, including their outstanding debt, operating expenses, lease payments and reserves or during the existence of a default.

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

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

Our First Lien Notes, First Lien Term Loans and Corporate Revolving Facility are effectively subordinated to certain project indebtedness.

Certain of our subsidiaries and other affiliates are separate and distinct legal entities and, except in limited circumstances, have no obligation to pay any amounts due with respect to our indebtedness or indebtedness of other subsidiaries or affiliates, and do not guarantee the payment of interest on or principal of such indebtedness. In the event of our bankruptcy, liquidation or reorganization (or the bankruptcy, liquidation or reorganization of a subsidiary or affiliate), such subsidiaries' or other affiliates' creditors, including trade creditors and holders of debt issued by such subsidiaries or affiliates, will generally be entitled to payment of their claims from the assets of those subsidiaries or affiliates before any assets are made available for distribution to us or the holders of our indebtedness. As a result, holders of our indebtedness will be effectively subordinated to all present and future debts and other liabilities (including trade payables) of certain of our subsidiaries. As of December 31, 2013, our subsidiaries had approximately $1.2 billion in debt from our CCFC subsidiary and approximately $1.9 billion in secured project financing from other subsidiaries, which are effectively senior to our First Lien Notes, First Lien Term Loans and Corporate Revolving Facility. We may incur additional project financing indebtedness in the future, which will be effectively senior to our other secured and unsecured debt.

Governmental Regulation

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

Federal policymakers have been considering imposing a national RPS on retail power providers. California already has an RPS in effect and in 2011 signed into law legislation requiring implementation of a 33% RPS by 2020. A number of additional states, including Maine, Minnesota, New York, Texas and Wisconsin, have an array of different RPS in place. Existing state-specific RPS requirements may change due to regulatory and/or legislative initiatives, and other states may consider implementing enforceable RPS in the future. A national RPS or more robust RPS in states in which we are active, coupled with economic incentives provided under the federal stimulus package, would likely initially drive up the number of wind and solar resources, increasing power supply to various markets which could negatively impact the dispatch of our natural gas-fired power plants, primarily in Texas and California.

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

State legislative and regulatory action, such as the actions taken in New Jersey and Maryland, could adversely impact our competitive position and business.

Certain states in the PJM market region, particularly New Jersey and Maryland, have taken anticompetitive actions that could have an adverse impact on the deregulated PJM power market by discouraging the construction of new generation. We are actively participating in the judicial process challenging these actions at the state and federal level. We believe the current competitive construct of the PJM power market whereby new construction of power generation facilities is determined by forward price signals and not ratepayer guaranteed rate recovery is the most efficient mechanism for incentivizing the construction of new power plants. As these judicial proceeding are ongoing, we cannot predict the ultimate impact on our financial condition, results of operations or cash flows.

If the federal district court decisions made during 2013 overturning these anticompetitive actions in New Jersey and Maryland are themselves overturned by the appellate courts, they could have an adverse impact on the deregulated PJM electricity markets by discouraging the construction of new generation which in turn could have a negative impact on our business prospects and financial results.

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

The CFTC has regulatory oversight of the futures markets, including trading on NYMEX for energy, and licensed futures professionals such as brokers, clearing members and large traders. In connection with its oversight of the futures markets and NYMEX, the CFTC regularly investigates market irregularities and potential manipulation of those markets. Recent laws also give the CFTC certain powers with respect to broker-type markets referred to as "exempt commercial markets" or ECMs, including the Intercontinental Exchange. The CFTC monitors activities in the OTC, ECM and physical markets that may be undertaken for the purpose of influencing futures prices. With respect to ECMs, the CFTC exercises only light-handed regulation primarily related to trade reporting, price dissemination and record retention (including retention of fraudulent claims and allegations).

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

The Dodd-Frank Act, which was signed into law on July 21, 2010, contains a variety of provisions designed to regulate financial markets, including credit and derivatives transactions. Title VII of the Dodd-Frank Act addresses regulatory reform of the OTC derivatives market in the U.S. and significantly changes the regulatory framework of this market. Certain Title VII regulations have been finalized and are effective though some regulations remain subject to a delayed compliance schedule. Other key regulations have not been finalized as of this time or remain in draft form. Until all of these regulations have been finalized, the extent to which the provisions of Title VII might affect our derivatives activities cannot be completely known.

While we are closely monitoring this rulemaking process from the CFTC (including related no-action relief, interpretations and orders), we have reviewed and assessed the impact of the CFTC's Title VII regulations on our business and related processes, and we have adjusted our internal procedures where necessary to comply with the applicable statutory law and related Title VII regulations which are effective at this time. We will continue to monitor all relevant developments and rulemaking initiatives, and we expect to successfully implement any new applicable requirements. At this time, we cannot predict the impact or possible additional costs to us related to the implementation of, or compliance with, the potential future requirements under the Dodd-Frank Act.

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

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

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

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

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

In 2011, the EPA finalized regulations governing GHG emissions from major sources as well as emissions of criteria and hazardous air pollutants from the electric generation sector. We continue to monitor and actively participate in the EPA initiatives where we anticipate a material impact on our business.

Further, air regulations enacted in New Jersey that further limit NO_X emissions from turbines and boilers beginning in 2015 will impact six of our power plants that will either need to retire or install additional NO_X controls to continue operating beyond 2015. We plan to install emissions controls equipment at two of these power plants and have provided notice to PJM of our intent to retire the four remaining power plants. We do not expect the retirement of these power plants or installation of emissions controls to have a material impact on our financial condition, results of operations or cash flows.

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

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

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

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

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

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

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

Risks Relating to Our Common Stock

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

As of December 31, 2013, four current holders (or related groups of holders) of our common stock have made filings with the SEC reporting beneficial ownership, directly or indirectly, individually or as members of a group, of 5% or more of the shares of our common stock. These shareholders, who together beneficially owned approximately 34% of our common stock at December 31, 2013, may be able to exercise substantial influence over all matters requiring shareholder approval, including the election of directors and approval of significant corporate action, such as mergers and other business combination transactions. If two or more of these shareholders (or groups of shareholders) vote their shares in the same manner, their combined stock ownership may effectively give significant influence over the election of our entire Board of Directors and significant influence over our management, operations and affairs. Currently, one member of our Board of Directors, the Chairman of our Board, is affiliated, directly or indirectly, with SPO Advisory Corp., one of these shareholders.

Circumstances may occur in which the interests of these shareholders could be in conflict with the interests of other shareholders. This concentration of ownership may also have the effect of delaying or preventing a change in control over us unless it is supported by these shareholders. Accordingly, the ability of our other shareholders to influence us through voting of their shares may be limited or the market price of our common stock may be adversely affected. Additionally, we have filed a registration statement on Form S-3 registering the resale of the common stock held by certain members of one of the four groups of these shareholders, which permits them to sell a large portion of their shares of common stock without being subject to the "trickle out" or other restrictions of Rule 144 under the Securities Act. Sales by any of the four shareholders of all or a substantial portion of their shares within a short period of time, could adversely affect the market price of our common stock or could further concentrate holdings of our common stock in the remaining three shareholders who hold more than 5% of our common stock.

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

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

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

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

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

Item 3. *Legal Proceedings*

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

Item 4. *Mine Safety Disclosures*

Not applicable.

PART II

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

Market Information and Stockholder Matters

Calpine Corporation common stock is traded on the NYSE under the symbol "CPN". The following table sets forth the high and low bid prices for our common stock for each quarter of the years 2013 and 2012, as reported on the NYSE.

	High	Low
2013		
First Quarter	$ 20.62	$ 17.95
Second Quarter	22.16	19.33
Third Quarter	21.97	18.59
Fourth Quarter	21.03	18.74
2012		
First Quarter	$ 17.60	$ 14.45
Second Quarter	19.03	15.90
Third Quarter	18.66	16.42
Fourth Quarter	18.87	16.47

As of December 31, 2013, there were 139 stockholders of record of our common stock.

We have never paid cash dividends on our common stock. Future cash dividends, if any, will be at the discretion of our Board of Directors and will depend upon, among other things, our future operations and earnings, capital requirements, general financial condition, contractual and financing restrictions and such other factors as our Board of Directors may deem relevant. See Item 1A. "Risk Factors," for a discussion of additional risks related to an investment in our common stock.

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)
October	1,906,397	$ 19.69	—	$ —
November	3,010,220	$ 19.34	2,083,344	$ 960
December	3,394,074	$ 19.15	3,382,700	$ 895
Total	8,310,691	$ 19.34	5,466,044	$ 895

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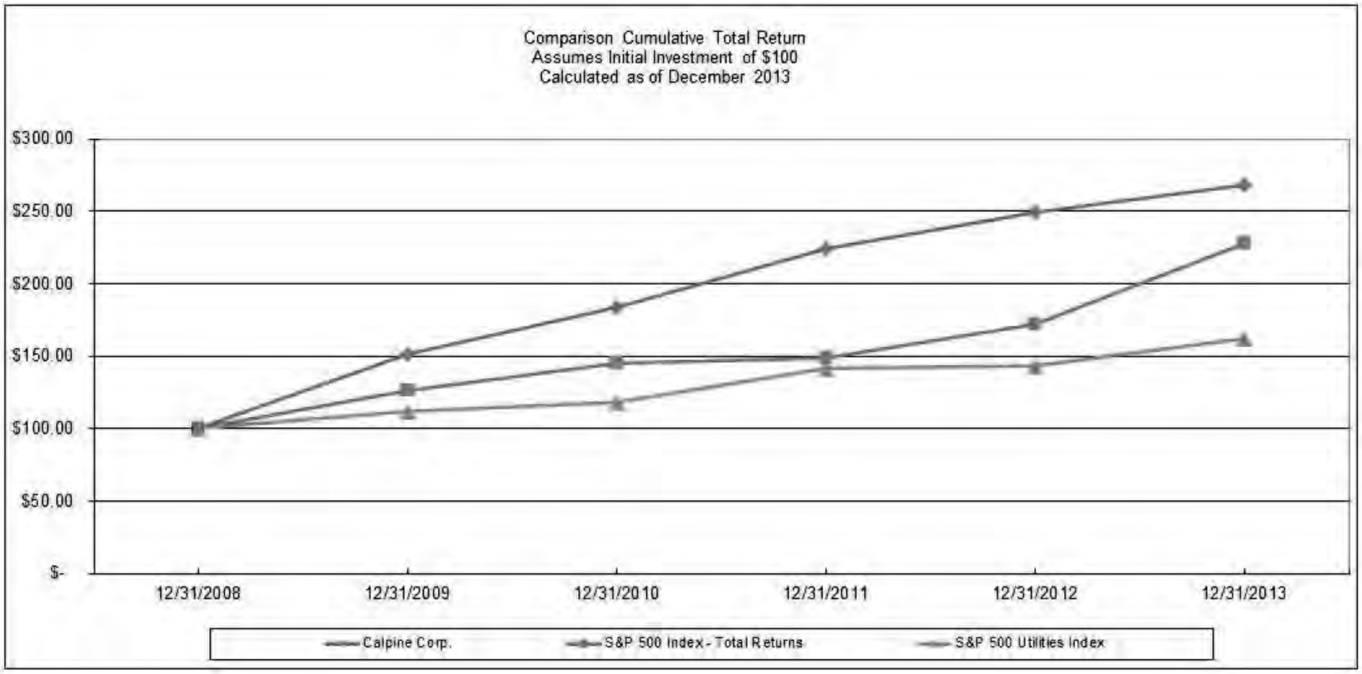
(1) Upon vesting of restricted stock awarded by us to employees, we withhold shares to cover employees' tax withholding obligations, other than for employees who have chosen to satisfy their tax withholding obligations in cash. During the fourth quarter of 2013, we withheld a total of 16,560 shares that are included in total number of shares purchased.

(2) Having previously authorized $600 million in repurchases of our common stock, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock in February 2013 and an additional $100 million in August 2013. Under the aggregate $1.1 billion of authorizations, we repurchased a total of 60,139,816 shares of our outstanding common stock at an average price of $18.29 per share. In November 2013, our Board of Directors authorized a new $1.0 billion multi-year share repurchase program, under which we have repurchased a total of 12,459,919 shares of our common stock for approximately $239 million at an average price of $19.15 per share as of the filing of this Report.

Stock Performance Graph

The performance graph below compares cumulative return on our common stock for the period December 31, 2008 through December 31, 2013, with the cumulative return of Standard & Poor's 500 Index (S&P 500) and the S&P 500 Utilities Index.

The graph below compares each period assuming that $100 was invested on December 31, 2008 in our common stock and each of above indices and that all dividends are reinvested. The returns shown below may not be indicative of future performance.



Company / Index	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011	December 31, 2012	December 31, 2013
Calpine Corporation....	$ 100	$ 151.10	$ 183.24	$ 224.30	$ 249.02	$ 267.97
S&P 500 Index...........	100	126.45	145.49	148.56	172.32	228.12
S&P Utilities Index.....	100	111.91	118.02	141.54	143.35	162.29

Item 6. ***Selected Financial Data***

SELECTED CONSOLIDATED FINANCIAL DATA

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(in millions, except earnings (loss) per share)				
Statement of Operations data:					
Operating revenues	$ 6,301	$ 5,478	$ 6,800	$ 6,545	$ 6,463
Income (loss) before discontinued operations attributable to Calpine	$ 14	$ 199	$ (190)	$ (162)	$ 114
Discontinued operations, net of tax expense, attributable to Calpine	—	—	—	193	35
Net income (loss) attributable to Calpine	$ 14	$ 199	$ (190)	$ 31	$ 149
Basic earnings (loss) per common share:					
Income (loss) before discontinued operations attributable to Calpine	$ 0.03	$ 0.43	$ (0.39)	$ (0.33)	$ 0.24
Discontinued operations, net of tax expense, attributable to Calpine	—	—	—	0.39	0.07
Net income (loss) per common share attributable to Calpine	$ 0.03	$ 0.43	$ (0.39)	$ 0.06	$ 0.31
Diluted earnings (loss) per common share:					
Income (loss) before discontinued operations attributable to Calpine	$ 0.03	$ 0.42	$ (0.39)	$ (0.33)	$ 0.24
Discontinued operations, net of tax expense, attributable to Calpine	—	—	—	0.39	0.07
Net income (loss) per common share attributable to Calpine	$ 0.03	$ 0.42	$ (0.39)	$ 0.06	$ 0.31
Balance Sheet data:					
Total assets	$ 16,559	$ 16,549	$ 17,371	$ 17,256	$ 16,650
Short-term debt and capital lease obligations	$ 204	$ 115	$ 104	$ 152	$ 463
Long-term debt and capital lease obligations	$ 10,908	$ 10,635	$ 10,321	$ 10,104	$ 8,996

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

Forward-Looking Information

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

INTRODUCTION AND OVERVIEW

Our Business

We are 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 execute commodity and commodity transportation 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. Seasonality and weather can have a significant impact on our results of operations and are also considered in our hedging and optimization activities.

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 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 three under construction (one new power plant and two expansions of existing power plants), located throughout 20 states in the U.S. and in Canada, with an aggregate current generation capacity of 28,104 MW and 699 MW under construction. We have also announced the acquisition of a 1,050 MW power plant in Texas that is expected to close in the first quarter of 2014. Our fleet, including projects under construction, consists of 75 combustion turbine-based plants, two fossil steam-based plants, 15 geothermal turbine-based plants and one photovoltaic solar plant. Our segments have an aggregate generation capacity of 7,524 MW in the West, 8,024 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.

Current Year Operational Developments

Our objective is to be the "best-in-class" in regards to certain operational performance metrics, such as safety, availability, reliability, efficiency and cost management. In addition, we continue to grow our presence in core markets with an emphasis on acquisitions, expansions or modernizations of existing power plants. Our notable operational performance metrics, significant projects under construction, growth initiatives and modernizations are discussed below:

- Our entire fleet achieved an exceptionally low forced outage factor of 1.6% and an impressive starting reliability of 98.5% during the year ended December 31, 2013.
- Our 619 MW Russell City Energy Center (Calpine's 75% net interest is 464 MW) and 309 MW Los Esteros Critical Energy Facility commenced commercial operations during the third quarter of 2013 and achieved average capacity factors of 63.9% and 28.0%, respectively, after COD.
- We commenced construction on the first phase of our Garrison Energy Center located in Dover, Delaware, during the second quarter of 2013 and expect COD during the second quarter of 2015.

- For the past thirteen consecutive years, our Geysers Assets have reliably generated approximately 6 million MWh of renewable power per year and, in 2013, achieved an exceptional availability factor of approximately 96%.
- We continue to make progress with our turbine modernization program and have ongoing expansion activities at our Deer Park and Channel Energy Centers in Texas which are expected to achieve COD during the second quarter of 2014. In addition, we have announced an agreement to purchase a natural gas-fired, combined-cycle power plant with a nameplate capacity of 1,050 MW located in Guadalupe County, Texas for approximately $625 million, which will increase capacity in our Texas segment.

Enhancing Shareholder Value

We continue to make significant progress to deliver financially disciplined growth, to enhance shareholder value through disciplined capital allocation and to set the foundation for future growth and success. Given our strong cash flow from operations, we are committed to remaining financially disciplined in our capital allocation decisions. The year ended December 31, 2013 was marked by the following accomplishments:

- Having previously authorized $600 million in repurchases of our common stock, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock in February 2013 and an additional $100 million in August 2013. Under the aggregate $1.1 billion of authorizations, we repurchased a total of 60,139,816 shares of our outstanding common stock at an average price of $18.29 per share. In November 2013, our Board of Directors authorized a new $1.0 billion multi-year share repurchase program, under which we have repurchased a total of 12,459,919 shares of our common stock for approximately $239 million at an average price of $19.15 per share as of the filing of this Report.
- In February 2013, we repriced our First Lien Term Loans by lowering the LIBOR floor by 0.25% to 1.0% and the margin over LIBOR by 0.25% to 3.0%.
- On May 3, 2013, CCFC, our indirect, wholly-owned subsidiary, entered into a credit agreement providing for a first lien senior secured term loan facility comprised of (i) a $900 million 7-year term loan and (ii) a $300 million 8.5-year term loan. CCFC utilized the proceeds received from the CCFC Term Loans to redeem the CCFC Notes which converted $1.0 billion in fixed rate debt to lower variable rate debt and extended the maturity.
- On June 27, 2013, we amended our Corporate Revolving Facility which lowered our costs and extended the maturity by more than two and half years.
- On October 31, 2013, we issued our 2024 First Lien Notes and used the proceeds to reduce our overall cost of debt and extend maturities by redeeming a portion of our 2019 First Lien Notes, 2020 First Lien Notes, 2021 First Lien Notes and 2023 First Lien Notes each of which carry a higher fixed interest rate.
- On December 2, 2013, we completed the repayment of our 2017 First Lien Notes with the proceeds from our 2020 First Lien Term Loan and 2022 First Lien Notes which will lower our annual interest expense and extend the maturity of approximately $1.1 billion in debt.

For a further discussion of our capital management and significant transactions completed in 2013, see "— Liquidity and Capital Resources."

Customer-Oriented Origination Business

We continue to focus on providing products and services that are beneficial to our customers. A summary of certain significant contracts entered into in 2013 is as follows:

- We entered into a new three-year PPA with South Carolina Electric and Gas Company to provide 200 MW of power generated by our Columbia Energy Center, commencing in January 2014.
- We entered into two new resource adequacy contracts with PG&E for our Delta and Sutter Energy Centers for the full capacity of each plant which commence in January and June 2014, respectively, and extend through December 2015 and 2016, respectively.
- We entered into two new PPAs with the Marin Energy Authority consisting of a one-year contract to provide 3 MW of renewable power during 2014 and a ten-year contract to provide 10 MW of renewable power commencing in January 2017. The renewable power to be delivered under both contracts will be generated from our Geysers Assets.
- We entered into a 100 MW financial PPA with a counterparty in PJM which commenced in November 2013 and extends through 2016.

- We entered into a new five-year PPA commencing in 2014 for approximately 50 MW and extended the existing steam agreement for ten years beyond 2016 with Celanese Ltd for power and steam generated from our Clear Lake Power Plant.
- We entered into a new ten-year PPA with the Sonoma Clean Power Authority to provide 10 MW of renewable power from our Geysers Assets commencing in May 2014. The capacity under contract will increase in increments each year, up to a maximum of 18 MW for years 2020 through 2023.

Our Regulatory and Environmental Profile

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

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

Our Market and Our Key Financial Performance Drivers

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

Fluctuations in natural gas price levels affect our Commodity Margin (depending on our hedge levels and holding other factors constant). When less efficient, higher cost natural gas-fired units set power prices in our regional markets, higher natural gas prices tend to increase our Commodity Margin. In these instances, while our production costs increase when natural gas prices are higher, our competitors' costs (and power prices) increase at a greater rate, leading to higher Commodity Margin. Similarly, when natural gas prices decline, our Commodity Margin tends to decline.

In 2012 and to a much lesser degree in 2013, given very low natural gas prices, natural gas-fired, combined-cycle units in many markets were frequently cheaper to dispatch than coal-fired power plants. When coal-fired electricity production costs exceed natural gas-fired production costs, coal-fired units tend to set power prices. In these hours, lower natural gas prices tend to increase our Commodity Margin, since our production costs fall while power prices remain constant (depending on our hedge levels and holding other factors constant).

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

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2013 AND 2012

Below are our results of operations for the year ended December 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	$ 6,374	$ 5,417	$ 957	18
Unrealized mark-to-market gain (loss)	(86)	48	(134)	#
Other revenue	13	13	—	—
Operating revenues	6,301	5,478	823	15
Operating expenses:				
Fuel and purchased energy expense:				
Commodity expense	3,808	2,894	(914)	(32)
Unrealized mark-to-market (gain) loss	(72)	130	202	#
Fuel and purchased energy expense	3,736	3,024	(712)	(24)
Plant operating expense	895	922	27	3
Depreciation and amortization expense	609	562	(47)	(8)
Sales, general and other administrative expense	136	140	4	3
Other operating expenses	81	78	(3)	(4)
Total operating expenses	5,457	4,726	(731)	(15)
(Gain) on sale of assets, net	—	(222)	(222)	#
(Income) from unconsolidated investments in power plants	(30)	(28)	2	7
Income from operations	874	1,002	(128)	(13)
Interest expense	696	736	40	5
Loss on interest rate derivatives	—	14	14	#
Interest (income)	(6)	(11)	(5)	(45)
Debt extinguishment costs	144	30	(114)	#
Other (income) expense, net	20	15	(5)	(33)
Income before income taxes	20	218	(198)	(91)
Income tax expense	2	19	17	89
Net income	18	199	(181)	(91)
Net income attributable to the noncontrolling interest	(4)	—	(4)	—
Net income attributable to Calpine	$ 14	$ 199	$ (185)	(93)

	2013	2012	Change	% Change
Operating Performance Metrics:				
MWh generated (in thousands)[(1)]	101,610	112,216	(10,606)	(9)
Average availability	91.7%	91.3%	0.4 %	—
Average total MW in operation[(1)]	26,854	27,318	(464)	(2)
Average capacity factor, excluding peakers	48.7%	53.7%	(5.0)%	(9)
Steam Adjusted Heat Rate	7,386	7,361	(25)	—

\# Variance of 100% or greater

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

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

Commodity revenue, net of Commodity expense, increased $43 million for the year ended December 31, 2013, compared to the year ended December 31, 2012, primarily due to:

- our Russell City and Los Esteros power plants commencing commercial operations during the third quarter of 2013 and the acquisition of Bosque Energy Center in November 2012 partially offset by the sale of Broad River and Riverside Energy Center in December 2012;
- higher regulatory capacity revenue in the North; and
- higher revenue from contracts in our West and Southeast segments which became effective in January 2013; partially offset by
- weaker market conditions in 2013 compared to 2012 in our Texas, North and Southeast segments partially offset by higher contribution from hedges related to these segments and stronger market conditions in our West segment partially offset by lower contribution from hedges in the West.

Generation decreased 9% primarily due to weaker market conditions and the sale of Broad River and Riverside Energy Center in December 2012 which were partially offset by the acquisition of Bosque Energy Center in November 2012 and our Russell City and Los Esteros power plants which commenced commercial operations during the third quarter of 2013. Our average total MW in operation decreased by 464 MW, or 2%, primarily due to the aforementioned changes in our power plant portfolio.

Unrealized mark-to-market gain/loss from hedging our future generation and fuel needs, for the year ended December 31, 2013, compared to the year ended December 31, 2012, had a favorable variance of $68 million primarily driven by overall increase in forward natural gas prices favorably affecting our natural gas hedges during the year ended December 31, 2013, as compared to the year ended December 31, 2012.

Plant operating expense decreased by $27 million for the year ended December 31, 2013, compared to the year ended December 31, 2012. Our normal, recurring plant operating expense decreased $59 million during 2013 compared to 2012 after excluding the net impact of a $12 million increase from power plant portfolio changes, a net $16 million increase in major maintenance expense resulting from our plant outage schedule net of costs from scrap parts related to outages and a $4 million increase related to higher stock-based compensation expense. The decrease in normal, recurring plant operating expense resulted primarily from a $30 million decrease in mainly production-related costs and salaries and benefits, a $12 million positive period-over-period change resulting from the TCEQ issuance of final regulations on Section 185 fees for which we determined we have no current or retroactive fee obligations, a $10 million period-over-period decrease in equipment failure cost related to outages and a $7 million decrease related to the restructuring of a ground lease in 2012.

Depreciation and amortization expense increased by $47 million for the year ended December 31, 2013, compared to the year ended December 31, 2012, primarily resulting from a $18 million increase due to our acquisition of the Bosque Energy Center in November 2012, a $12 million increase related to our Russell City and Los Esteros power plants commencing commercial operations in August 2013 and a $9 million increase due to the timing of assets placed into service net of assets fully depreciated during 2013.

Gain on sale of assets, net consists of a $215 million gain related to the sale of 100% of our ownership interests in Broad River, and a $7 million gain related to the sale of our Riverside Energy Center, both of which closed in December 2012. See Note 3 of the Notes to Consolidated Financial Statements for further information.

Interest expense decreased by $40 million for the year ended December 31, 2013, compared to the year ended December 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 6.7% for the year ended December 31, 2013, from 7.3% for the year ended December 31, 2012. The issuance of our CCFC Term Loans in June 2013 and 2019 First Lien Term Loan in October 2012 allowed us to reduce our overall cost of debt by replacing our CCFC Notes and a portion of our First Lien Notes and variable rate project debt with term loans carrying lower variable interest rates. Also, in February 2013, we repriced our First Lien Term Loans by lowering our interest rate, which decreased our interest expense during the year ended December 31, 2013. See Note 6 of the Notes to the Consolidated Financial Statements for further information regarding our debt.

Loss on interest rate derivatives had a favorable change of $14 million for the year ended December 31, 2013, compared to the year ended December 31, 2012, resulting from the termination in March 2012 of our legacy interest rate swaps formerly hedging our First Lien Credit Facility. During the year ended December 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 year ended December 31, 2013, consisted primarily of $139 million relating to the repayment of the CCFC Notes and the 2017 First Lien Notes and redeeming a portion of our First Lien Notes during 2013, which is comprised of $96 million of prepayment penalties and $43 million associated with the write-off of unamortized debt discount and deferred financing costs. Debt extinguishment costs for the year ended December 31, 2012, consisted of $18 million associated with the redemption premium, the write-off of unamortized deferred financing costs and debt premium and discount related to repayment of a portion of our First Lien Notes and variable rate project debt during the fourth quarter of 2012, and $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.

During the year ended December 31, 2013, we recorded an income tax expense of $2 million compared to an income tax expense of $19 million for the year ended December 31, 2012. The favorable year-over-year change primarily resulted from a decrease in income tax expense of $21 million related to the expiration of applicable statutes of limitation related to uncertain tax positions and a decrease of $8 million related to the application of intraperiod tax allocation for the year ended December 31, 2013, compared to the year ended December 31, 2012. The overall favorable year-over-year change in income tax expense was partially offset by a refund of approximately $10 million received in October 2012 related to the IRS approval of our 2004 amended federal income tax return.

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

Below are our results of operations for the year ended December 31, 2012, as compared to the same period in 2011 (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.

	2012	2011	Change	% Change
Operating revenues:				
Commodity revenue	$ 5,417	$ 6,753	$ (1,336)	(20)
Unrealized mark-to-market gain	48	35	13	37
Other revenue	13	12	1	8
Operating revenues	5,478	6,800	(1,322)	(19)
Operating expenses:				
Fuel and purchased energy expense:				
Commodity expense	2,894	4,299	1,405	33
Unrealized mark-to-market loss	130	60	(70)	#
Fuel and purchased energy expense	3,024	4,359	1,335	31
Plant operating expense	922	904	(18)	(2)
Depreciation and amortization expense	562	550	(12)	(2)
Sales, general and other administrative expense	140	131	(9)	(7)
Other operating expenses	78	77	(1)	(1)
Total operating expenses	4,726	6,021	1,295	22
(Gain) on sale of assets, net	(222)	—	222	#
(Income) from unconsolidated investments in power plants	(28)	(21)	7	33
Income from operations	1,002	800	202	25
Interest expense	736	760	24	3
Loss on interest rate derivatives	14	145	131	90
Interest (income)	(11)	(9)	2	22
Debt extinguishment costs	30	94	64	68
Other (income) expense, net	15	21	6	29
Income (loss) before income taxes	218	(211)	429	#
Income tax expense (benefit)	19	(22)	(41)	#
Net income (loss)	199	(189)	388	#
Net income attributable to the noncontrolling interest	—	(1)	1	#
Net income (loss) attributable to Calpine	$ 199	$ (190)	$ 389	#

	2012	2011	Change	% Change
Operating Performance Metrics:				
MWh generated (in thousands)(1)	112,216	90,875	21,341	23
Average availability	91.3%	90.1%	1.2%	1
Average total MW in operation(1)	27,318	27,234	84	—
Average capacity factor, excluding peakers	53.7%	44.3%	9.4%	21
Steam Adjusted Heat Rate	7,361	7,412	51	1

\# Variance of 100% or greater

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

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

Commodity revenue, net of Commodity expense, increased $69 million for the year ended December 31, 2012, compared to the year ended December 31, 2011, primarily due to:

- higher contribution from hedges primarily in our Texas segment during the third quarter of 2012 compared to the third quarter of 2011;
- higher generation in our Texas and North segments due to lower natural gas prices during 2012 compared to 2011 and higher generation in our West segment due to improved market conditions, less hydroelectric generation and a nuclear power plant outage in California during 2012; and
- an extreme cold weather event in Texas that occurred on February 2, 2011, and resulted in unplanned outages at some of our power plants, negatively impacting our revenue for the year ended December 31, 2011, which did not reoccur in 2012; partially offset by
- lower regulatory capacity revenue during 2012 compared to 2011; and
- the expiration of contracts which decreased revenue during the year ended December 31, 2012 compared to the year ended December 31, 2011.

Generation increased 23% primarily due to lower natural gas prices in our Texas segment during certain periods in the first half of 2012 and in our North segment during certain periods throughout 2012 and improved market conditions, less hydroelectric generation and a nuclear power plant outage in our West segment during the year ended December 31, 2012. During the year ended December 31, 2012, generation increased as natural gas prices were low enough that during certain periods some of our modern, natural gas-fired, combined-cycle power plants in Texas and PJM became less expensive on a marginal basis than coal-fired generation resulting in these plants running baseload. The increase in generation also resulted in a 1% decrease in our Steam Adjusted Heat Rate for the year ended December 31, 2012, compared to the year ended December 31, 2011, as our power plants tend to operate more efficiently under baseload operations. Our average total MW in operation increased by 84 MW primarily due to the acquisition of our 762 MW Bosque Energy Center, our 565 MW York Energy Center which achieved COD in March 2011 and an increase in capacity resulting from our turbine modernization program partially offset by the temporary shut down of our Los Esteros Critical Energy Facility associated with the upgrade from simple-cycle to combined-cycle technology.

Unrealized mark-to-market gain/loss from hedging our future generation and fuel needs, for the year ended December 31, 2012, compared to the year ended December 31, 2011, had an unfavorable variance of $57 million primarily driven by the realization of favorable natural gas hedge positions in 2012 previously reported in unrealized mark-to-market gain/loss at December 31, 2011, partially offset by settlements during 2012 of Heat Rate hedge positions that were unfavorable based on forward curves at December 31, 2011.

Despite a 23% increase in generation, our normal, recurring plant operating expense was largely unchanged for the year ended December 31, 2012, compared to the year ended December 31, 2011, after accounting for $20 million in reimbursements for insurance claims from prior periods that disproportionately reduced our plant operating expense for the year ended December 31, 2011.

Depreciation and amortization expense increased by $12 million for the year ended December 31, 2012, compared to the year ended December 31, 2011, primarily resulting from a decrease of $17 million for the year ended December 31, 2011 related to a revision in the expected settlement dates of the asset retirement obligations related to our natural gas-fired and geothermal power plants, partially offset by a decrease of $2 million resulting from lower depreciation associated with the sale of Broad River in December 2012.

Gain on sale of assets, net consists of a $215 million gain related to the sale of 100% of our ownership interests in Broad River, and a $7 million gain related to the sale of our Riverside Energy Center, both of which closed in December 2012. See Note 3 of the Notes to Consolidated Financial Statements for further information.

Income from unconsolidated investments in power plants increased for the year ended December 31, 2012, compared to the year ended December 31, 2011, primarily due to a $3 million favorable change in fair value related to hedging activities associated with derivative contracts at Greenfield LP, a $2 million increase in operating income for Whitby due to the expiration of an unfavorable natural gas transportation contract in 2011 and a $1 million increase in operating income for Greenfield LP due to lower natural gas prices in 2012 compared to 2011.

Interest expense decreased by $24 million for the year ended December 31, 2012, compared to the year ended December 31, 2011, 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 7.3% for the year ended December 31, 2012, from 7.6% for the year ended December 31, 2011. The issuance of our First Lien Term Loans in 2011 and 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 corporate level term loans carrying a lower variable interest rate. See Note 6 of the Notes to Consolidated Financial Statements for further information regarding the issuance of our First Lien Term Loans, the repayment of the portion of our First Lien Notes and the repayment of variable rate project debt.

Loss on interest rate derivatives had a favorable change of $131 million for the year ended December 31, 2012, compared to the year ended December 31, 2011, primarily resulting from $91 million of historical unrealized losses previously deferred in AOCI and reclassified into income in January 2011 in connection with the retirement of the First Lien Credit Facility term loans. Also contributing to the year-over-year change was a favorable change of $40 million resulting from interest rate swap breakage costs related to the repayment of project debt in June 2011 and changes in fair value and settlements subsequent to the reclassification date of the interest rate swaps formerly hedging our First Lien Credit Facility term loans. See Note 8 of the Notes to Consolidated Financial Statements for further discussion of our interest rate swaps formerly hedging our First Lien Credit Facility term loans.

Debt extinguishment costs for the year ended December 31, 2012, consisted of $18 million associated with the redemption premium, the write-off of unamortized deferred financing costs and debt premium and discount related to repayment of a portion of our First Lien Notes and variable rate project debt during the fourth quarter of 2012, and $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. Debt extinguishment costs for the year ended December 31, 2011, primarily consisted of $74 million associated with the repayment of the NDH Project Debt in March 2011, $19 million associated with the retirement of the First Lien Credit Facility term loans in January 2011 in connection with the issuance of the 2023 First Lien Notes and $5 million related to the write-off of unamortized deferred financing costs related to the repayment of project debt in June 2011.

During the year ended December 31, 2012, we recorded an income tax expense of $19 million compared to an income tax benefit of $22 million for the year ended December 31, 2011. The unfavorable year-over-year change primarily resulted from a one-time $76 million benefit to reduce our valuation allowance due to the election to consolidate the CCFC group with the Calpine group for 2011 federal income tax reporting purposes. Also, contributing to the unfavorable year-over-year change was a decrease of $14 million in income tax expense for 2011 due to the expiration of a statute of limitation related to an uncertain tax position. The overall unfavorable year-over-year change in income tax expense was partially offset by a refund of approximately $10 million received in October 2012 related to the IRS approval of our 2004 amended federal income tax return and a decrease in income tax expense for 2012 of $39 million primarily related to the application of intraperiod tax allocation and a decrease in various state and foreign jurisdiction income taxes for the year ended December 31, 2012, compared to the year ended December 31, 2011.

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 16 of the Notes to Consolidated Financial Statements for a reconciliation of Commodity Margin to income (loss) from operations by segment.

Commodity Margin by Segment for the Years Ended December 31, 2013 and 2012

The following tables show our Commodity Margin and related operating performance metrics by segment for the years ended December 31, 2013 and 2012 (exclusive of the noncontrolling interest). 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)	$ 1,020	$ 994	$ 26	3
Commodity Margin per MWh generated	$ 28.25	$ 29.77	$ (1.52)	(5)
MWh generated (in thousands)	36,110	33,390	2,720	8
Average availability	92.2%	91.9%	0.3%	—
Average total MW in operation	7,058	6,742	316	5
Average capacity factor, excluding peakers	62.6%	60.6%	2.0%	3
Steam Adjusted Heat Rate	7,308	7,278	(30)	—

West — Commodity Margin in our West segment increased by $26 million, or 3%, for the year ended December 31, 2013 compared to the year ended December 31, 2012. During 2013, Commodity Margin was positively impacted by our contracted 464 MW Russell City and 309 MW Los Esteros power plants which commenced commercial operations during the third quarter of 2013 and were also the primary drivers of a 316 MW, or 5%, increase in our average total MW in operation. The increase in Commodity Margin was also due to higher revenue from a tolling contract which became effective in January 2013 and stronger market conditions resulting from lower hydroelectric generation, warmer weather and the impact of the January 1, 2013 implementation of the AB 32 carbon market. The impact of these positive factors was partially offset by lower contribution from hedges during the year ended December 31, 2013 compared to 2012. Generation increased 8% period-over-period due primarily to our Russell City and Los Esteros power plants and the stronger market conditions in 2013 compared to 2012.

Texas:	2013	2012	Change	% Change
Commodity Margin (in millions)	$ 632	$ 570	$ 62	11
Commodity Margin per MWh generated	$ 18.95	$ 15.86	$ 3.09	19
MWh generated (in thousands)	33,343	35,946	(2,603)	(7)
Average availability	89.8%	91.1%	(1.3)%	(1)
Average total MW in operation	7,784	7,127	657	9
Average capacity factor, excluding peakers	48.9%	57.4%	(8.5)%	(15)
Steam Adjusted Heat Rate	7,198	7,147	(51)	(1)

Texas — Commodity Margin in our Texas segment increased by $62 million, or 11%, for the year ended December 31, 2013 compared to the year ended December 31, 2012, due to higher contribution from hedges and the acquisition of our 762 MW Bosque Energy Center in November 2012 which was also the primary driver of the 657 MW, or 9%, increase in our average total MW in operation. The overall period-over-period increase in Commodity Margin was partially offset by lower realized market Spark Spreads resulting from weaker market conditions during the first nine months of 2013 partially offset by stronger market conditions during the fourth quarter of 2013. Generation decreased 7% resulting from weaker market conditions in the first nine months of 2013 partially offset by the acquisition of Bosque Energy Center. Our average capacity factor decreased 15% resulting from lower generation at our legacy power plants during 2013 compared to 2012.

North:	2013	2012	Change	% Change
Commodity Margin (in millions)	$ 712	$ 729	$ (17)	(2)
Commodity Margin per MWh generated	$ 42.34	$ 33.55	$ 8.79	26
MWh generated (in thousands)	16,817	21,732	(4,915)	(23)
Average availability	91.5%	89.3%	2.2 %	2
Average total MW in operation	6,776	7,375	(599)	(8)
Average capacity factor, excluding peakers	44.4%	48.8%	(4.4)%	(9)
Steam Adjusted Heat Rate	7,963	7,914	(49)	(1)

North — Commodity Margin in our North segment increased by $56 million for the year ended December 31, 2013 compared to the year ended December 31, 2012, after excluding a decrease of $73 million resulting from the sale of Riverside Energy Center in December 2012 which was also the primary driver of a 599 MW, or 8%, decrease in our average total MW in operation. The increase in Commodity Margin was primarily due to higher regulatory capacity revenues, partially offset by weaker market conditions driven by milder weather and higher natural gas prices which drove a reversal of coal-to-gas switching during the year ended December 31, 2013 compared to 2012. Generation decreased 23% due to weaker market conditions during 2013 and the sale of Riverside Energy Center.

Southeast:	2013	2012	Change	% Change
Commodity Margin (in millions)	$ 204	$ 245	$ (41)	(17)
Commodity Margin per MWh generated	$ 13.30	$ 11.59	$ 1.71	15
MWh generated (in thousands)	15,340	21,148	(5,808)	(27)
Average availability	95.0%	93.4%	1.6 %	2
Average total MW in operation	5,236	6,074	(838)	(14)
Average capacity factor, excluding peakers	34.2%	44.6%	(10.4)%	(23)
Steam Adjusted Heat Rate	7,353	7,309	(44)	(1)

Southeast — Commodity Margin in our Southeast segment increased by $11 million for the year ended December 31, 2013 compared to the year ended December 31, 2012, after excluding a decrease of $52 million resulting from the sale of Broad River in December 2012 which was also the driver of an 838 MW, or 14%, decrease in our average total MW in operation. The increase in Commodity Margin was primarily due to higher revenue from a new contract which became effective in January 2013 and higher contribution from hedges during 2013 compared to 2012. The increase in Commodity Margin was partially offset by weaker market conditions resulting from milder weather and higher natural gas prices which drove a reversal of coal-to-gas switching during 2013 compared to 2012. Generation decreased 27% due to weaker market conditions during 2013 and the sale of Broad River.

Commodity Margin by Segment for the Years Ended December 31, 2012 and 2011

The following tables show our Commodity Margin and related operating performance metrics by segment for the years ended December 31, 2012 and 2011. 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 consolidated and operate.

West:	**2012**	**2011**	**Change**	**% Change**
Commodity Margin (in millions)	$ 994	$ 1,061	$ (67)	(6)
Commodity Margin per MWh generated	$ 29.77	$ 44.54	$ (14.77)	(33)
MWh generated (in thousands)	33,390	23,823	9,567	40
Average availability	91.9%	88.2%	3.7%	4
Average total MW in operation	6,742	6,895	(153)	(2)
Average capacity factor, excluding peakers	60.6%	43.6%	17.0%	39
Steam Adjusted Heat Rate	7,278	7,418	140	2

West — Commodity Margin in our West segment decreased by $67 million, or 6%, for the year ended December 31, 2012 compared to the year ended December 31, 2011, due to lower contribution from hedges, lower market power prices associated with our Geysers Assets which are based on absolute power price and lower revenue due to the expiration of contracts. The decrease was partially offset by an increase in Commodity Margin on our open position driven by higher market Spark Spreads and a 40% increase in generation driven primarily by improved market conditions, less hydroelectric generation and a nuclear power plant outage in California during 2012. Our average total MW in operation decreased 153 MW, or 2%, due primarily to the temporary shut down of our Los Esteros Critical Energy Facility at the end of 2011 associated with the upgrade from simple-cycle to combined-cycle technology partially offset by an increase in capacity resulting from our turbine modernization program.

Texas:	**2012**	**2011**	**Change**	**% Change**
Commodity Margin (in millions)	$ 570	$ 469	$ 101	22
Commodity Margin per MWh generated	$ 15.86	$ 14.41	$ 1.45	10
MWh generated (in thousands)	35,946	32,552	3,394	10
Average availability	91.1%	89.0%	2.1%	2
Average total MW in operation	7,127	6,988	139	2
Average capacity factor, excluding peakers	57.4%	53.2%	4.2%	8
Steam Adjusted Heat Rate	7,147	7,243	96	1

Texas — Commodity Margin in our Texas segment increased by $101 million, or 22%, for the year ended December 31, 2012 compared to the year ended December 31, 2011, due to higher contribution from hedges that secured favorable pricing despite lower settled market prices driven by milder weather primarily in the third quarter of 2012 compared to the same period in 2011. We also realized higher Commodity Margin from a 10% increase in generation in 2012 driven by lower natural gas prices. Generation increased as natural gas prices were low enough during certain periods in the first half of 2012 that some of our modern, natural gas-fired, combined-cycle power plants in Texas became less expensive on a marginal basis than coal-fired generation resulting in these plants running baseload. Also contributing to the year-over-year increase was the negative impact to Commodity Margin in the first quarter of 2011 due to unplanned outages at some of our power plants caused by an extreme cold weather event which occurred on February 2, 2011. Our average total MW in operation increased 139 MW due to the acquisition of our 762 MW Bosque Energy Center in the fourth quarter of 2012 and an increase in capacity resulting from our turbine modernization program.

North:	2012	2011	Change	% Change
Commodity Margin (in millions)	$ 729	$ 704	$ 25	4
Commodity Margin per MWh generated	$ 33.55	$ 45.37	$ (11.82)	(26)
MWh generated (in thousands)	21,732	15,517	6,215	40
Average availability	89.3%	91.6%	(2.3)%	(3)
Average total MW in operation	7,375	7,268	107	1
Average capacity factor, excluding peakers	48.8%	35.9%	12.9 %	36
Steam Adjusted Heat Rate	7,914	7,919	5	—

North — Commodity Margin in our North segment increased by $25 million, or 4%, for the year ended December 31, 2012 compared to the year ended December 31, 2011, primarily due to our York Energy Center which achieved COD in March 2011, higher contribution from hedges and a 40% increase in generation resulting from lower natural gas prices. During the year ended December 31, 2012, generation increased as natural gas prices were low enough that during certain periods some of our Mid-Atlantic modern, natural gas-fired, combined-cycle power plants became less expensive on a marginal basis than coal-fired generation resulting in these power plants running baseload. The increase in Commodity Margin was partially offset by lower regulatory capacity revenues and a decline in nodal pricing in PJM during the year ended December 31, 2012 compared to 2011. Average total MW in operation increased 107 MW, or 1%, due primarily to our 565 MW York Energy Center and an increase in capacity resulting from our turbine modernization program.

Southeast:	2012	2011	Change	% Change
Commodity Margin (in millions)	$ 245	$ 240	$ 5	2
Commodity Margin per MWh generated	$ 11.59	$ 12.64	$ (1.05)	(8)
MWh generated (in thousands)	21,148	18,983	2,165	11
Average availability	93.4%	91.9%	1.5%	2
Average total MW in operation	6,074	6,083	(9)	—
Average capacity factor, excluding peakers	44.6%	40.6%	4.0%	10
Steam Adjusted Heat Rate	7,309	7,312	3	—

Southeast — Commodity Margin in our Southeast segment increased by $5 million, or 2%, for the year ended December 31, 2012 compared to the year ended December 31, 2011, primarily due to higher contribution from hedges and an 11% increase in generation largely driven by lower natural gas prices. The increase in Commodity Margin was largely offset by the negative impact from the expiration of a contract during the third quarter of 2012.

Adjusted EBITDA

We define Adjusted EBITDA, a non-GAAP financial measure, as EBITDA adjusted for certain items described below and presented in the accompanying reconciliation. Adjusted EBITDA is not a measure calculated in accordance with U.S. GAAP, and should be viewed as a supplement to, and not a substitute for, our results of operations presented in accordance with U.S. GAAP. Adjusted EBITDA is not intended to represent cash flows from operations or net income (loss) as defined by U.S. GAAP as an indicator of operating performance. Furthermore, Adjusted EBITDA is not necessarily comparable to similarly-titled measures reported by other companies.

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

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

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

The tables below provide a reconciliation of Adjusted EBITDA to our income (loss) from operations on a segment basis and to net income (loss) attributable to Calpine on a consolidated basis for years ended December 31, 2013, 2012 and 2011 (in millions).

	2013					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 14
Net income attributable to the noncontrolling interest						4
Income tax expense						2
Debt extinguishment costs and other (income) expense, net						164
Interest expense, net of interest income						690
Income from operations	$ 280	$ 190	$ 395	$ 8	$ 1	$ 874
Add:						
Adjustments to reconcile income from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs[1]	241	165	130	74	(1)	609
Major maintenance expense	70	96	29	29	—	224
Operating lease expense	9	—	26	—	—	35
Unrealized (gain) loss on commodity derivative mark-to-market activity	62	(24)	(14)	(10)	—	14
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude the noncontrolling interest[2]	(13)	—	27	—	—	14
Stock-based compensation expense	12	13	5	6	—	36
Loss on dispositions of assets	2	1	—	1	—	4
Acquired contract amortization	—	—	14	—	—	14
Other	13	—	(1)	(6)	—	6
Total Adjusted EBITDA	$ 676	$ 441	$ 611	$ 102	$ —	$ 1,830

	2012					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 199
Income tax expense						19
Debt extinguishment costs and other (income) expense, net						45
Loss on interest rate derivatives						14
Interest expense, net of interest income						725
Income from operations	$ 252	$ 216	$ 353	$ 177	$ 4	$ 1,002
Add:						
Adjustments to reconcile income from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	203	142	135	87	(3)	564
Major maintenance expense	67	64	43	26	—	200
Operating lease expense	9	—	25	—	—	34
Unrealized (gain) loss on commodity derivative mark-to-market activity	104	(66)	5	39	—	82
(Gain) on sale of assets, net	—	—	(7)	(215)	—	(222)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(2)	—	—	31	—	—	31
Stock-based compensation expense	8	8	4	5	—	25
Loss on dispositions of assets	3	6	3	1	(1)	12
Acquired contract amortization	—	—	14	—	—	14
Other	1	1	3	2	—	7
Total Adjusted EBITDA	$ 647	$ 371	$ 609	$ 122	$ —	$ 1,749

	2011					
	West	**Texas**	**North**	**Southeast**	**Consolidation and Elimination**	**Total**
Net loss attributable to Calpine						$ (190)
Net income attributable to the noncontrolling interest						1
Income tax benefit						(22)
Debt extinguishment costs and other (income) expense, net						115
Loss on interest rate derivatives						145
Interest expense, net of interest income						751
Income (loss) from operations	$ 518	$ (49)	$ 343	$ (17)	$ 5	$ 800
Add:						
Adjustments to reconcile income (loss) from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	192	135	138	92	(5)	552
Major maintenance expense	58	81	23	43	—	205
Operating lease expense	9	—	26	—	—	35
Unrealized (gain) on commodity derivative mark-to-market activity	(106)	123	3	5	—	25
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(2)	—	—	36	—	—	36
Stock-based compensation expense	10	7	3	4	—	24
Loss on dispositions of assets	8	4	2	2	—	16
Acquired contract amortization	—	—	8	—	—	8
Other	11	1	11	2	—	25
Total Adjusted EBITDA	$ 700	$ 302	$ 593	$ 131	$ —	$ 1,726

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

(2) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include unrealized (gain) loss on mark-to-market activity of nil, nil and $1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

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

The following table provides a summary of our liquidity position at December 31, 2013 and 2012 (in millions):

	2013	2012
Cash and cash equivalents, corporate(1)	$ 649	$ 1,153
Cash and cash equivalents, non-corporate	292	131
Total cash and cash equivalents	941	1,284
Restricted cash	272	253
Corporate Revolving Facility availability	758	757
CDHI letter of credit facility availability(2)	7	—
Total current liquidity availability	$ 1,978	$ 2,294

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(1) Includes $5 million and $11 million of margin deposits posted with us by our counterparties at December 31, 2013 and 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 December 31, 2013, we had no outstanding letters of credit issued in excess of $225 million under our CDHI letter of credit facility that were collateralized by cash.

Our principal source for future liquidity is cash flows generated from our operations. 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. See "Cash Flow Activities" below for a further discussion of our change in cash and cash equivalents.

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.

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 at January 17, 2014, an increase of $1/MMBtu in natural gas prices would result in an decrease of collateral required by approximately $35 million. If natural gas prices decreased by $1/MMBtu, we estimate that our collateral requirements would increase by approximately $118 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 January 17, 2014, an increase of 500 Btu/KWh in the Market Heat Rate would result in an increase in collateral required by approximately $42 million. If Market Heat Rates were to fall at a similar rate, we estimate that our collateral required would decrease by $39 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 2014 and beyond. In addition to the price of natural gas, 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, significant transactions, construction, modernizations 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 December 31, 2013 and 2012 (in millions):

	2013	2012
Corporate Revolving Facility	$ 242	$ 243
CDHI	218	253
Various project financing facilities	170	130
Total	$ 630	$ 626

Capital Management and Significant Transactions

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

Share Repurchase Program

Having previously authorized $600 million in repurchases of our common stock, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock in February 2013 and an additional $100 million in August 2013. Under the aggregate $1.1 billion of authorizations, we repurchased a total of 60,139,816 shares of our outstanding common stock at an average price of $18.29 per share. In November 2013, our Board of Directors authorized a new $1.0 billion multi-year share repurchase program, under which we have repurchased a total of 12,459,919 shares of our common stock for approximately $239 million at an average price of $19.15 per share as of the filing of this Report.

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 the margin over LIBOR by 0.25% to 3.0%.

CCFC Refinancing

On May 3, 2013, CCFC, our indirect, wholly-owned subsidiary, entered into a credit agreement providing for a first lien senior secured term loan facility comprised of (i) a $900 million 7-year term loan and (ii) a $300 million 8.5-year term loan. CCFC utilized the proceeds received from the CCFC Term Loans to redeem the CCFC Notes which converted $1.0 billion in fixed rate debt to lower variable rate debt and extended the maturity. See Note 6 of the Notes to Consolidated Financial Statements for further description of our CCFC Term Loans and costs incurred associated with the redemption of the CCFC Notes.

Corporate Revolving Facility Amendment

On June 27, 2013, we amended our Corporate Revolving Facility which lowered our costs and extended the maturity by more than two and half years. See Note 6 of the Notes to Consolidated Financial Statements for further description of the amendment to our Corporate Revolving Facility.

2024 First Lien Notes

On October 31, 2013, we issued $490 million in aggregate principal amount of our 2024 First Lien Notes and used the proceeds to redeem 10% of the original aggregate principal amount of our 2019 First Lien Notes, 2020 First Lien Notes, 2021 First Lien Notes and 2023 First Lien Notes at a redemption price of 103% of the principal amount redeemed, plus accrued and unpaid interest. The redemption will reduce our overall cost of debt. See Note 6 of the Notes to Consolidated Financial Statements for further description of our 2024 First Lien Notes.

2020 First Lien Term Loan, 2022 First Lien Notes and Repayment of the 2017 First Lien Notes

On December 2, 2013, we completed the repayment of our 2017 First Lien Notes with the proceeds from our 2020 First Lien Term Loan and 2022 First Lien Notes which will lower our annual interest expense and extend the maturity of approximately $1.1 billion in debt. See Note 6 of the Notes to Consolidated Financial Statements for further description of our 2020 First Lien Term Loan, 2022 First Lien Notes and repayment of our 2017 First Lien Notes.

Construction, Modernizations and Growth Initiatives

Our goal is to continue to grow our presence in core markets with an emphasis on acquisitions, 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 — Our Russell City Energy Center commenced commercial operations in August 2013 which brought on line approximately 429 MW of net interest baseload capacity (464 MW with peaking capacity) representing our 75% share. 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 ten-year 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 has increased the efficiency and environmental performance of the power plant by lowering the Heat Rate. Our Los Esteros Critical Energy Facility commenced commercial operations in August 2013.

Texas:

Channel and Deer Park Expansions — In the fourth quarter of 2012, we began construction to expand the baseload capacity of our Deer Park and Channel Energy Centers by approximately 260 MW each. Each power plant features an oversized steam turbine that, along with existing plant infrastructure, allows us to add capacity and improve the power plant's overall efficiency at a meaningful discount to the market cost of building new capacity. We expect COD on the expansions of our Channel and Deer Park Energy Centers during the second quarter of 2014.

Guadalupe Energy Center — On December 2, 2013, we announced an agreement to purchase a natural gas-fired, combined-cycle power plant with a nameplate capacity of 1,050 MW located in Guadalupe County, Texas for approximately $625 million, which will increase capacity in our Texas segment. The purchase price does not include $15 million in consideration for the rights we also acquired to an advanced development opportunity for an approximately 400 MW quick-start, natural gas-fired peaker, if market conditions warrant. We are currently evaluating funding sources for the acquisition of this power plant including, but not limited to, nonrecourse financing, corporate financing or internally generated funds.

North:

Garrison Energy Center — Garrison Energy Center is a 309 MW combined-cycle project located in Delaware on a site secured by a long-term lease with the City of Dover. Construction commenced in April 2013, and we expect COD during the second quarter of 2015. The project's capacity cleared PJM's 2015/2016 and 2016/2017 base residual auctions. We are currently evaluating funding sources for the construction of this project including, but not limited to, nonrecourse financing, corporate financing or internally generated funds. We are in the early stages of development of a second phase (309 MW) of this project. PJM has completed the feasibility and system impact studies for this phase and the facilities study is currently underway.

Mankato Power Plant Expansion — We are proposing a 345 MW expansion of the Mankato Power Plant in response to a competitive resource acquisition process for approximately 500 MW of new capacity established by the Minnesota Public Utilities Commission ("MPUC"). The initial stage of the proceeding was managed via a contested case hearing. On December 31, 2013, the Administrative Law Judge ("ALJ") in the contested case issued a non-binding recommendation to the MPUC that the state should secure approximately 100 MW of distributed solar resources at this time and defer procurement of new thermal resources. Xcel Energy (Northern States Power) and the Minnesota Department of Commerce subsequently filed exceptions to the ALJ decision and continue to advocate in support of new, natural gas-fired generation resources. The MPUC will hold deliberations and decide whether to accept, reject or modify the ALJ recommendation in early 2014.

PJM Development Opportunities — We are currently evaluating opportunities to develop more than 1,000 MW in the PJM market area that feature cost advantages such as existing infrastructure and favorable transmission queue positions. These projects are continuing to advance entitlements (permits, zoning, transmission, etc.) for their potential development at a future date.

All Segments:

Turbine Modernization — We continue to move forward with our turbine modernization program. Through December 31, 2013, we have completed the upgrade of twelve Siemens and eight GE turbines totaling approximately 200 MW and have committed to upgrade approximately four additional turbines. Similarly, we have the opportunity at several of our power plants in Texas to implement further turbine modernizations to add as much as 500 MW of incremental capacity across the region at attractive prices. In addition, we have begun a program to update our dual-fueled turbines at certain of our power plants in our North segment. Our decision to invest in these turbine modernizations depends upon, among other things, further clarity on market design reforms currently being considered.

Major Maintenance and Capital Spending

Our major maintenance and capital spending remains an important part of our business. Our expected expenditures for 2014 are as follows (in millions):

	2014
Major maintenance expense	$ 220
Capital expenditures, operations, net	160
Growth related capital expenditures[(1)]	870
Total major maintenance expense and capital spending	1,250
Less: Amounts expected to be funded with financing	(30)
Net major maintenance expense and capital spending	$ 1,220

(1) Includes $625 million to purchase Guadalupe Energy Center, a natural gas-fired, combined-cycle power plant with a nameplate capacity of 1,050 MW located in Guadalupe County, Texas and $15 million in consideration for the rights acquired to an advanced development opportunity for an approximately 400 MW quick-start, natural gas-fired peaker, if market conditions warrant.

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, 2013, our consolidated federal NOLs totaled approximately $7.5 billion. See Note 10 of the Notes to Consolidated Financial Statements for further discussion of our NOLs.

Cash Flow Activities

The following table summarizes our cash flow activities for the years ended December 31, 2013, 2012 and 2011 (in millions):

	2013	2012	2011
Beginning cash and cash equivalents	$ 1,284	$ 1,252	$ 1,327
Net cash provided by (used in):			
Operating activities	549	653	775
Investing activities	(593)	(470)	(836)
Financing activities	(299)	(151)	(14)
Net increase (decrease) in cash and cash equivalents	(343)	32	(75)
Ending cash and cash equivalents	$ 941	$ 1,284	$ 1,252

2013 — 2012

Net Cash Provided By Operating Activities

Cash provided by operating activities for the year ended December 31, 2013, was $549 million compared to $653 million for the year ended December 31, 2012. The decrease was primarily due to:

- *Working capital employed* — Working capital employed increased by approximately $129 million for the year ended December 31, 2013, compared to the year ended December 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 was primarily due to a $125 million increase in net accounts receivable/accounts payable balances resulting from higher than normal revenue in December 2013.

- *Debt extinguishment payments* — For the year ended December 31, 2013, we made cash payments of $101 million associated with the redemption of the CCFC Notes and a portion of certain First Lien Notes compared to cash payments of $29 million in prepayment premiums for the year ended December 31, 2012 associated with the repayment of a portion of our First Lien Notes and variable rate project debt.

- *AB32 compliance requirements* — Operating cash flows decreased by approximately $31 million due to an increase in net assets required for AB32 compliance. We had no such compliance requirements for the year ended December 31, 2012.

- *Cash paid for income taxes (net)* — Cash paid for income taxes, net of refunds received, was $19 million for year ended December 31, 2013, as compared to $1 million for the year ended December 31, 2012.
- *Income from operations* — Income from operations, adjusted for non-cash items, increased by $73 million for the year ended December 31, 2013, compared to the year ended December 31, 2012. Non-cash items consist primarily of depreciation and amortization, income from unconsolidated investments in power plants and unrealized mark-to-market activity.
- *Interest paid* — Cash paid for interest decreased by $47 million to $672 million for the year ended December 31, 2013, compared to $719 million for the year ended December 31, 2012. The decrease was primarily due to the replacement of 10% of our fixed interest rate First Lien Notes with a corporate level term loan at a variable interest rate, the re-pricing of our First Lien Term Loans and the repayment of project debt.
- *Ground lease modification* — For the year ended December 31, 2012, we paid $28 million related to a renegotiated ground lease at one of our operating plants. We made no similar payments for the year ended December 31, 2013.

Net Cash Used In Investing Activities

Cash used in investing activities for the year ended December 31, 2013 was $593 million compared to $470 million for the year ended December 31, 2012. The increase was primarily due to:

- *Proceeds from the sale of power plants, interests and other* — For the year ended December 31, 2013, we had $1 million in proceeds received as compared to $825 million for the year ended December 31, 2012, which was due to the sale of 100% of our ownership interests in each of the Broad River Entities and the sale of our Riverside Energy Center.
- *Purchase of Bosque Energy Center* — In 2012, we purchased a natural gas-fired, combined-cycle power plant located in Bosque County, Texas for $432 million. There were no acquisitions in 2013.
- *Settlement of non-hedging interest rate swaps* — During the year ended December 31, 2012, we terminated our legacy interest rate swaps formerly hedging our First Lien Credit Facility resulting in payments of approximately $156 million. We made no similar payments during the year ended December 31, 2013.
- *Capital expenditures* — Capital expenditures for the year ended December 31, 2013 were $575 million, a decrease of $62 million, compared to expenditures of $637 million for the year ended December 31, 2012. The decrease was primarily due to timing on our construction projects and turbine modernization program.
- *Restricted cash* — Restricted cash increased $18 million for the year ended December 31, 2013, compared to an increase of $59 million for the year ended December 31, 2012. The decrease was primarily due to the release of cash collateral previously posted under our CDHI letter of credit facility.

Net Cash Used In Financing Activities

Cash used in financing activities increased by $148 million to $299 million for the year ended December 31, 2013, compared to cash used in financing activities of $151 million for the year ended December 31, 2012. The increase was primarily due to:

- *Stock repurchases* — During the year ended December 31, 2013, we made payments of approximately $623 million to repurchase our common stock as compared to $463 million during the year ended December 31, 2012.
- *Lower proceeds from First Lien Term Loans* — During the year ended December 31, 2013, we received proceeds of approximately $390 million from the issuance of the 2020 First Lien Term Loan, a decrease of $445 million when compared to $835 million received during the year ended December 31, 2012, from the issuance of the 2019 First Lien Term Loan.
- *Repayments of First Lien Notes* — During the year ended December 31, 2013, we redeemed the 2017 First Lien Notes along with 10% of the original aggregate principal amounts of the First Lien Notes for $1.6 billion as compared to $590 million for the year ended December 31, 2012 related to 10% redemption of the aggregate principal amount of each series of our then existing First Lien Notes. The redemption in 2013 was funded from the $390 million in proceeds from the issuance of the 2020 First Lien Term Loan together with $1.2 billion in proceeds from the issuance of the 2022 First Lien Notes and 2024 First Lien Notes.
- *Lower proceeds from project debt* — During the year ended December 31, 2013, we received proceeds of approximately $182 million from project debt, compared to $389 million during the year ended December 31, 2012. The decrease was related to lower draws on our Russell City Project Debt and Los Esteros Project Debt.

- *Increased finance costs* — During the year ended December 31, 2013, we incurred finance costs of approximately $53 million, compared to approximately $20 million during the year ended December 31, 2012. The increase was primarily due to the CCFC Term Loans, the re-pricing of our First Lien Term Loans and the issuances of the 2020 First Lien Term Loan, 2022 First Lien Notes and 2024 First Lien Notes.
- *CCFC refinancing* — During the year ended December 31, 2013, we received proceeds of approximately $1.2 billion under the CCFC Term Loans and used approximately $1.0 billion to repay the CCFC Notes, for net proceeds of $197 million.
- *Proceeds from First Lien Notes* — During the year ended December 31, 2013, we received proceeds of approximately $1.2 billion under the 2022 First Lien Notes and 2024 First Lien Notes, which were used to redeemed the 2017 First Lien Notes along with 10% of the original aggregate principal amounts of the First Lien Notes.
- *Repayments of project debt, notes payable and other* — During the year ended December 31, 2013, we made repayments of $66 million primarily due to the repayment of the Pasadena and Steamboat project debt. During the year ended December 31, 2012, we made repayments of $289 million primarily due to the retirement of the BRSP project debt.

2012 — 2011

Net Cash Provided By Operating Activities

Cash provided by operating activities for the year ended December 31, 2012, was $653 million compared to $775 million for the year ended December 31, 2011. The decrease in cash provided by operating activities was primarily due to:

- *Working capital* — Working capital employed increased by approximately $58 million for the year ended December 31, 2012 compared to 2011 after adjusting for debt related balances and non-hedging interest rate swaps which did not impact cash provided by operating activities. The increase was primarily due to increased margin requirements during the year ended December 31, 2012.
- *Interest paid* — Cash paid for interest increased by $63 million to $719 million for the year ended December 31, 2012, as compared to $656 million for 2011. The increase was primarily due to timing of interest payments on our First Lien Notes and First Lien Term Loans partially offset by lower payments on our NDH Project Debt and other project debt.
- *Prepayment premiums* — For the year ended December 31, 2012, we paid $29 million in prepayment premiums related to a repayment of a portion of our First Lien Notes and our variable rate project debt compared to $13 million in prepayment premiums related to the extinguishment of the NDH Project Debt for the year ended December 31, 2011.
- *Ground lease modification* — For the year ended December 31, 2012, we paid $28 million related to a renegotiated ground lease at one of our operating plants. We made no similar payments for the year ended December 31, 2011.
- *Income from operations* — Income from operations, adjusted for non-cash items increased by $45 million for the year ended December 31, 2012, as compared to 2011. Non-cash items consist primarily of depreciation and amortization, gains and losses on sales of assets, impairment losses, income and losses from unconsolidated investments and unrealized gains and losses in mark-to-market activity.

Net Cash Used In Investing Activities

Cash flows used in investing activities for the year ended December 31, 2012, was $470 million compared to cash flows used in investing activities of $836 million for the year ended December 31, 2011. The decrease was primarily due to:

- *Capital expenditures* — Payments made for capital expenditures for the year ended December 31, 2012, were approximately $637 million, compared to payments of approximately $683 million for the year ended December 31, 2011. The year-over-year decrease was primarily due to the timing of cash payments.
- *Higher proceeds from sales of power plants, interests and other* — For the year ended December 31, 2012, we received proceeds of approximately $825 million related to the sale of 100% of our ownership interests in each of the Broad River Entities and the sale of our Riverside Energy Center, compared to proceeds of approximately $13 million from the disposition of other plant assets for the year ended December 31, 2011.
- *Settlement of non-hedging interest rate swaps* — During the year ended December 31, 2012 we terminated our legacy interest rate swaps formerly hedging our First Lien Credit Facility resulting in payments of $156 million, compared to payments of $189 million during the same period in 2011.

- *Transmission credits* — During the year ended December 31, 2012, we paid $12 million for transmission credits related to the construction of our Russell City Energy Center compared to $31 million paid during the year ended December 31, 2011.
- *Purchase of power plant* — In 2012 we purchased a natural gas-fired, combined-cycle power plant located in Bosque County, Texas for approximately $432 million. There were no acquisitions in 2011.
- *Restricted cash* — Restricted cash increased by $59 million for the year ended December 31, 2012, compared to a decrease of $54 million for the same period in 2011. The increase was primarily due to additional cash collateral requirements related to the change in capacity under the CDHI letter of credit facility associated with the completion of the sale of the Riverside Energy Center. The decrease in restricted cash in 2011 was primarily due to the maturity of project debt and the corresponding reduction in restricted cash requirements.

Net Cash Used In Financing Activities

Cash flows used in financing activities were $151 million for the year ended December 31, 2012, compared to $14 million for the year ended December 31, 2011. The increase in cash flows used in financing activities was primarily due to:

- *Lower net borrowings under the First Lien Term Loans* — During the year ended December 31, 2012, we received proceeds of approximately $835 million from the issuance of the 2019 First Lien Term Loan, an $822 million decrease compared to the $1.7 billion in proceeds received from the 2018 First Lien Term Loans issued in the year ended December 31, 2011.
- *Repayments of First Lien Term Loans* — During the year ended December 31, 2012, we redeemed 10% of the aggregate principal amount of each series of our existing First Lien Notes for approximately $590 million and made no similar redemption during the year ended December 31, 2011. The redemption in 2012 was funded from the $835 million in proceeds received from the issuance of the 2019 First Lien Term Loan.
- *Stock repurchases* — During the year ended December 31, 2012, we made payments under the share repurchase program of approximately $463 million, compared to payments of approximately $119 million for the year ended December 31, 2011.
- *Decreased contributions from noncontrolling interest holder* — During the year ended December 31, 2012, we received no proceeds from a noncontrolling interest holder in Russell City Energy Company, LLC, compared to approximately $33 million for the year ended December 31, 2011.
- *Repayments on NDH Project Debt* — During the year ended December 31, 2012, we made no repayments on the NDH Project Debt, compared to payments of approximately $1.3 billion for the year ended December 31, 2011. This repayment was funded by the $1.7 billion in proceeds received from the issuance of the 2018 First Lien Term Loans during the year ended December 31, 2011.
- *Lower repayments of project debt, notes payable and other* — During the year ended December 31, 2012, we made repayments of approximately $289 million, primarily due to the retirement of the BRSP project debt. During the year ended December 31, 2011, we made repayments of $550 million, primarily due to the repayment of the Deer Park and Metcalf project debt.
- *Increased proceeds from project debt, notes payable and other* — During the year ended December 31, 2012, we received proceeds of approximately $389 million related to our Russell City Project Debt and Los Esteros Project Debt, compared to $327 million for the same period in 2011.
- *Lower financing costs* — During the year ended December 31, 2012, we paid financing costs of approximately $20 million compared to approximately $81 million for the year ended December 31, 2011.

Counterparties and Customers

Our counterparties primarily consist of three categories of entities who participate in the wholesale energy markets: financial institutions and trading companies; regulated utilities, municipalities, cooperatives, ISOs and other retail power suppliers; and oil, natural gas, chemical and other energy-related industrial companies. We have exposure to trends within the energy industry, including declines in the creditworthiness of our counterparties. We have concentrations of credit risk with a few of our commercial customers relating to our sales of power, steam and hedging and optimization activities. Currently, certain of our counterparties within the energy industry have below investment grade credit ratings. We believe that our credit policies and portfolio of transactions adequately monitor and diversify our credit risk, and currently our counterparties are performing according to their respective agreements.

Credit Considerations

Our credit rating has, among other things, generally required us to post significant collateral with our hedging counterparties. Our collateral is generally in the form of cash deposits, letters of credit or first liens on our assets. See also Note 9 of the Notes to Consolidated Financial Statements for our use of collateral. Our credit rating reduces the number of hedging counterparties willing to extend credit to us and reduces our ability to negotiate more favorable terms with them. However, we believe that we will continue to be able to work with our hedging counterparties to execute beneficial hedging transactions and provide adequate collateral. At December 31, 2013, our First Lien Notes, First Lien Term Loans, Corporate Revolving Facility and our corporate rating had the following ratings and commentary from Standard and Poor's and Moody's Investors Service:

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

Off Balance Sheet Arrangements

Our power plant operating leases are not reflected on our Consolidated Balance Sheets and contain customary restrictions on dividends up to Calpine Corporation, additional debt and further encumbrances similar to those typically found in project finance debt instruments. See Note 15 of the Notes to Consolidated Financial Statements for the future minimum lease payments under our power plant operating leases.

Some of our unconsolidated equity method investments have debt that is not reflected on our Consolidated Balance Sheets. As of December 31, 2013, our equity method investees (Greenfield LP and Whitby) had aggregate debt outstanding of $395 million. Based on our pro rata share of each of the investments, our share of such debt would be approximately $198 million. All such debt is non-recourse to us. See Note 5 of the Notes to Consolidated Financial Statements for additional information on our investments.

Guarantee Commitments — As part of our normal business operations, we enter into various agreements providing, or otherwise arranging, financial or performance assurance to third parties on behalf of our subsidiaries in the ordinary course of such subsidiaries' respective business. Such arrangements include guarantees, standby letters of credit and surety bonds for power and natural gas purchase and sale arrangements and contracts associated with the development, construction, operation and maintenance of our fleet of power plants. These arrangements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our primary commercial obligations as of December 31, 2013, are as follows (in millions):

	Amounts of Commitment Expiration per Period						
Guarantee Commitments	2014	2015	2016	2017	2018	Thereafter	Total Amounts Committed
Guarantee of subsidiary debt[1]	$ 36	$ 37	$ 36	$ 26	$ 31	$ 178	$ 344
Standby letters of credit[2][4]	562	11	—	20	—	37	630
Surety bonds[3][4][5]	—	—	—	—	—	27	27
Guarantee of subsidiary operating lease payments[4]	7	4	—	—	—	—	11
Total	$ 605	$ 52	$ 36	$ 46	$ 31	$ 242	$ 1,012

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

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

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

(4) These are contingent off balance sheet obligations.

(5) As of December 31, 2013, $4 million of cash collateral is outstanding related to these bonds.

Contractual Obligations — Our contractual obligations as of December 31, 2013, are as follows (in millions):

	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Operating lease obligations[1]	$ 524	$ 57	$ 99	$ 95	$ 273
Purchase obligations:					
Turbine commitments	$ 15	$ 12	$ 3	$ —	$ —
Commodity purchase obligations[2]	2,187	385	528	459	815
LTSA	134	10	18	28	78
Cost to complete construction projects	118	108	10	—	—
Parts supply agreements[3]	918	120	238	168	392
Other purchase obligations[4]	579	45	91	67	376
Total purchase obligations[5]	$ 3,951	$ 680	$ 888	$ 722	$ 1,661
Debt[6]	$ 11,125	$ 190	$ 377	$ 2,267	$ 8,291
Other contractual obligations:					
Interest payments on debt[6][7]	$ 4,680	$ 576	$ 1,236	$ 1,305	$ 1,563
Liability for uncertain tax positions	32	—	—	—	32
Interest rate swap agreement[7]	135	48	67	19	1
Total other contractual obligations	$ 4,847	$ 624	$ 1,303	$ 1,324	$ 1,596

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

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

(3) Our parts supply agreements are generally cancelable upon payment of an insubstantial termination fee.

(4) The amounts presented here include water agreements, maintenance agreements and other purchase obligations.

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

(6) A note payable totaling $15 million associated with the sale of the PG&E note receivable to a third party is excluded from debt for this purpose as it is a non-cash liability.

(7) Amounts are projected based upon interest rates at December 31, 2013.

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 of this Report, these entities included: Calpine Gilroy Cogen, L.P., Calpine Gilroy 1, Inc., Calpine King City Cogen, LLC, Calpine Securities Company, L.P. (a parent company of Calpine King City Cogen, LLC), Calpine King City, LLC (an indirect parent company of Calpine Securities Company, L.P.), Russell City Energy Company, LLC and OMEC.

During the fourth quarter of 2013, we closed on the purchase of the remaining third party equity interest in GEC Holdings, LLC pursuant to the purchase agreement that was executed in October 2013. In the first quarter of 2014, we modified the operating agreement for GEC Holdings, LLC whereby it is no longer a special purpose subsidiary.

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 estimates 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 Statements of Operations in unrealized mark-to-market gain/loss as a component of operating revenues (for power and environmental product 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 Statements of Operations and could create 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 2014 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 8 of the Notes to Consolidated 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 $0.6 billion at December 31, 2013, when compared to approximately $0.4 billion at December 31, 2012, and our derivative liabilities have increased to approximately $0.7 billion at December 31, 2013, when compared to approximately $0.6 billion at December 31, 2012. At December 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 2% and 3%, respectively). See Note 7 of the Notes to Consolidated Financial Statements for further information related to our level 3 derivative assets and liabilities.

The change in fair value of our outstanding commodity and interest rate derivative instruments from January 1, 2013, through December 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]	(22)	41	19
Fair value attributable to new contracts	(29)	—	(29)
Changes in fair value attributable to price movements	44	38	82
Changes in fair value attributable to nonperformance risk	—	(3)	(3)
Fair value of contracts outstanding at December 31, 2013[3]	$ (24)	$ (120)	$ (144)

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(1) Commodity contract settlements consist of roll-off of previously recognized gains on contracts not designated as hedging instruments of $106 million (represents a portion of Commodity revenue and Commodity expense as reported on our Consolidated Statements of Operations) and $84 million related to current period gains from other changes in derivative assets and liabilities not reflected in OCI or earnings.

(2) Interest rate settlements consist of $25 million related to roll-off of losses from settlements of designated cash flow hedges and $16 million related to roll-off of losses from settlements of undesignated interest rate swaps (represents a portion of interest expense as reported on our Consolidated Statements of Operations).

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

The change since the last balance sheet date in the total value of the derivatives (both assets and liabilities) is reflected either in cash for option premiums paid or collected, in OCI, net of tax for cash flow hedges, or on our Consolidated Statements of Operations as a component (gain or loss) in 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 Statements of Operations for the years ended December 31, 2013, 2012 and 2011 (in millions):

	2013	2012	2011
Realized gain (loss)[1]			
Commodity derivative instruments	$ 86	$ 387	$ 143
Interest rate swaps	—	(157)	(193)
Total realized gain (loss)	$ 86	$ 230	$ (50)
Unrealized gain (loss)[2]			
Commodity derivative instruments	$ (14)	$ (82)	$ (25)
Interest rate swaps	2	154	55
Total unrealized gain (loss)	$ (12)	$ 72	$ 30
Total mark-to-market activity, net	$ 74	$ 302	$ (20)

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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.

	2013	2012	2011
Realized and unrealized gain (loss)			
Derivatives contracts included in operating revenues	$ (119)	$ 187	$ (20)
Derivatives contracts included in fuel and purchased energy expense	191	118	138
Interest rate swaps included in interest expense	2	11	7
Loss on interest rate derivatives	—	(14)	(145)
Total mark-to-market activity, net	$ 74	$ 302	$ (20)

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 December 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	2014	2015-2016	2017-2018	After 2018	Total
Prices actively quoted	$ 7	$ (63)	$ (6)	$ —	$ (62)
Prices provided by other external sources	21	(6)	—	—	15
Prices based on models and other valuation methods	13	10	—	—	23
Total fair value	$ 41	$ (59)	$ (6)	$ —	$ (24)

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 years ended December 31, 2013 and 2012 (in millions):

	2013	2012
Year ended December 31:		
High	$ 80	$ 76
Low	$ 33	$ 33
Average	$ 52	$ 56
As of December 31	$ 46	$ 76

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.

Beginning in the fourth quarter of 2012 and continuing throughout 2013, we have experienced 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 volatility in our earnings.

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

Credit Risk — Credit risk relates to the risk of loss resulting from 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 practices adequately monitor our credit risk, and currently our counterparties are performing 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 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 December 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 December 31, 2013)	2014	2015-2016	2017-2018	After 2018	Total
Investment grade	$ 41	$ (59)	$ (6)	$ —	$ (24)
Non-investment grade	—	—	—	—	—
No external ratings	—	—	—	—	—
Total fair value	$ 41	$ (59)	$ (6)	$ —	$ (24)

Interest Rate Risk — We are exposed to interest rate risk related to our variable rate debt. Interest rate risk represents the potential loss in earnings arising from adverse changes in market interest rates. Our variable rate financings are indexed to base rates, generally LIBOR. The following table summarizes the contract terms as well as the fair values of our debt instruments exposed to interest rate risk as of December 31, 2013. All outstanding balances and fair market values are shown gross of applicable premium or discount, if any (in millions):

	2014	2015	2016	2017	2018	Thereafter	Total	Fair Value December 31, 2013
Debt by Maturity Date:								
Fixed Rate	$ 24	$ 9	$ 9	$ 7	$ 7	$ 5,054	$ 5,110	$ 5,429
Average Interest Rate	8.6%	5.4%	5.7%	6.5%	6.5%	7.3%		
Variable Rate	$ 142	$ 141	$ 146	$ 516	$ 1,670	$ 3,071	$ 5,686	$ 5,684
Average Interest Rate(1)	3.0%	3.2%	4.2%	6.0%	6.7%	7.3%		

(1) Projection based upon forward LIBOR rates inferred from spot rates at December 31, 2013.

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 $(13) million at December 31, 2013.

APPLICATION OF CRITICAL ACCOUNTING POLICIES

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

Revenue Recognition

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

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

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

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

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

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

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

Gross vs. Net Accounting — We determine whether the financial statement presentation of revenues should be on a gross or net basis. Where we act as principal, we record settlement of our physical commodity contracts on a gross or net basis dependent upon whether the contract results in physical delivery of the underlying product. With respect to our physical executory contracts, where we do not take title to the commodities but receive a variable payment to convert natural gas into power and steam in a tolling operation, we record revenues on a net basis.

Fair Value Measurements

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

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

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

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

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

Derivative Instruments and Valuation Techniques

The primary factors affecting the fair value of our derivative instruments at any point in time are the volume of open derivative positions (MMBtu, MWh and $ notional amounts); changing commodity market prices, 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. Derivative contracts can be exchange-traded or OTC. For OTC derivatives that trade in liquid markets, model inputs can generally be verified and model selection does not involve significant management judgment. Certain OTC derivatives trade in less liquid markets with limited pricing information, and the determination of fair value for these derivatives is inherently more difficult.

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

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

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

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

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

Impairments

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

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

Acquisitions of Assets and Liabilities

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

Accounting for Derivative Instruments

We recognize all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for, and we elect, the normal purchase normal sale exemption. For transactions in which we elect the normal purchase normal sale exemption, gains and losses are not reflected on our Consolidated Statements of Operations until the 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 Statements of Operations and could create 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 Statements of Cash Flows unless they contain an other-than-insignificant financing element in which case their cash flows are classified within financing activities.

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

Cash Flow Hedges — We report the effective portion of the unrealized gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument as a component of OCI and reclassify such gains and losses into earnings in the same period during which the hedged forecasted transaction affects earnings. Gains and losses due to ineffectiveness on commodity hedging instruments are recognized currently in earnings and are separately stated on our Consolidated 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, interest rate and environmental product 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 Statements of Operations in unrealized mark-to-market gain/loss as a component of operating revenues (for power and environmental product 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 Statement of Operations for the year ended December 31, 2012, and approximately $142 million reflected the realization of losses recorded in prior periods.

See Notes 7 and 8 of the Notes to Consolidated Financial Statements for further discussion of our derivative instruments.

Accounting for VIEs and Financial Statement Consolidation Criteria

We consolidate all VIEs where we determined that we have both the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or receive benefits from the VIE. We have determined that we hold the obligation to absorb losses and receive benefits in all of our VIEs where we hold the majority equity interest. Therefore, our determination of whether to consolidate is based upon which variable interest holder has the power to direct the most significant activities of the VIE (the primary beneficiary). Our analysis includes consideration of the following primary activities which we believe to have a significant impact on a power plant's financial performance: operations and maintenance, plant dispatch, and fuel strategy as well as our ability to control or influence contracting and overall plant strategy. Our approach to determining which entity holds the powers and rights is based on powers held as of the balance sheet date. Contractual terms that may change the powers held in future periods, such as a purchase or sale option, are not considered in our analysis. Based on our analysis, we believe that we hold the power and rights to direct the most significant activities of all our majority owned VIEs.

Under our consolidation policy and under U.S. GAAP we also:

- perform an ongoing reassessment each reporting period of whether we are the primary beneficiary of our VIEs; and
- evaluate if an entity is a VIE and whether we are the primary beneficiary whenever any changes in facts and circumstances occur such that the holders of the equity investment at risk, as a group, lose the power from voting rights or similar rights of those investments to direct the activities of a VIE that most significantly impact the VIE's economic performance or when there are other changes in the powers held by individual variable interest holders.

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

Disclosure Requirements

U.S. GAAP requires separate disclosure on the face of our Consolidated 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

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 Balance Sheets. Our equity interest in the net income from Greenfield LP and Whitby for the years ended December 31, 2013, 2012 and 2011, are recorded in (income) from unconsolidated investments in power plants.

We hold a call option to purchase the Inland Empire Energy Center (a 775 MW natural gas-fired power plant located in California) 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.

Long-Lived Assets and Depreciation Expense

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

We depreciate our assets under the straight-line method over the shorter of their estimated useful lives or lease term. For our natural gas-fired power plants, we assume an estimated salvage value which approximates 10% of the depreciable cost basis where we own the power plant or have a favorable option to purchase the power plant or take ownership of the power plant at conclusion of the lease term and approximately 0.15% of the depreciable costs basis for rotable equipment. For our Geysers Assets, we typically assume no salvage values. We use the component depreciation method for our natural gas-fired power plant rotable parts and our information technology equipment and the composite depreciation method for most of all of the other natural gas-fired power plant asset groups and Geysers Assets.

Impairment Evaluation of Long-Lived Assets (Including Intangibles and Investments)

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

- a significant decrease in the market price of a long-lived asset;

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

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

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

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

Accounting for Income Taxes

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

For federal income tax reporting purposes, our historical tax reporting group was comprised primarily of two separate groups, CCFC and its subsidiaries, which we referred to as the CCFC group, and Calpine Corporation and its subsidiaries other than CCFC, which we referred to as the Calpine group. During the first quarter of 2011, we elected to consolidate our CCFC and Calpine groups for federal income tax reporting purposes and Calpine filed a consolidated federal income tax return for the year ended December 31, 2011 that included the CCFC group. As a result of the consolidation, the CCFC group deferred tax liabilities will be eligible to offset existing Calpine group NOLs that were reserved by a valuation allowance. Accordingly, we recorded a one-time federal deferred income tax benefit of approximately $76 million during the first quarter of 2011 to reduce our valuation allowance.

Our NOL carryforwards consist primarily of federal NOL carryforwards of approximately $7.5 billion, which expire between 2023 and 2033, and NOL carryforwards in 33 states and the District of Columbia totaling approximately $4.1 billion, which expire between 2014 and 2033, substantially all of which are offset with a full valuation allowance. We also have approximately $900 million in foreign NOLs, which expire between 2026 and 2033, substantially all of which are offset with a full valuation allowance. The NOL carryforwards available are subject to limitations on their annual usage. Under federal and applicable state income tax laws, a corporation is generally permitted to deduct from taxable income in any year NOLs carried forward from prior years subject to certain time limitations as prescribed by the taxing authorities. Under federal income tax law, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of the IRC. We experienced an ownership change on the Effective Date as a result of the cancellation of our old common stock and the distribution of our new common stock pursuant to our Plan of Reorganization. However, this ownership change and the resulting annual limitations are not expected to result in the expiration of our NOL carryforwards if we are able to generate sufficient future taxable income within the carryforward periods.

In the ordinary course of business, there are many transactions and calculations where the ultimate tax outcome is uncertain. Some of these uncertainties arise as a consequence of the treatment of capital assets, financing transactions, multistate taxation of operations and segregation of foreign and domestic income and expense to avoid double taxation. We recognize the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination. A tax position that meets the more-likely-than-not recognition threshold is measured as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement with a taxing authority. We reverse a previously recognized tax position in the first period in which it is no longer more likely than not that the tax position would be sustained upon examination. The determination and calculation of uncertain tax positions involves significant judgment in the application of complex tax laws. Resolution of these uncertainties in a manner inconsistent with our expectations could have a material impact on our financial condition or results of operations. As of December 31, 2013, we had $68 million of unrecognized tax benefits from uncertain tax positions.

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

New Accounting Standards and Disclosure Requirements

See Note 2 of the Notes to Consolidated Financial Statements for a discussion of new accounting standards and disclosure requirements.

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

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

Item 8. *Financial Statements and Supplementary Data*

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

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

None.

Item 9A. *Controls and Procedures*

Disclosure Controls and Procedures

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

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

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP.

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

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

Management has assessed the effectiveness of our internal control over financial reporting as of December 31, 2013. In making its assessment of internal control over financial reporting, management used the criteria described in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on management's assessment, management has concluded that our internal control over financial reporting was effective as of December 31, 2013 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external reporting purposes in accordance with U.S. GAAP.

The effectiveness of our internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of 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.

Item 9B. *Other Information*

None.

PART III

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

Identification of Executive Officers

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

Name	Age	Principal Occupation
Jack A. Fusco.........	51	Chief Executive Officer
John B. Hill............	46	President and Chief Operating Officer
Zamir Rauf.............	54	Executive Vice President and Chief Financial Officer
W. Thaddeus Miller	63	Executive Vice President, Chief Legal Officer and Secretary
Jim D. Deidiker......	58	Senior Vice President and Chief Accounting Officer

Jack A. Fusco has served as our Chief Executive Officer and as a member of our Board of Directors since August 10, 2008. He also served as our President from August 2008 to December 2012. From July 2004 to February 2006, Mr. Fusco served as the Chairman and Chief Executive Officer of Texas Genco LLC. From 2002 through July 2004, Mr. Fusco was an exclusive energy investment advisor for Texas Pacific Group. From November 1998 until February 2002, he served as President and Chief Executive Officer of Orion Power Holdings, Inc. Prior to his founding of Orion Power Holdings, Inc., Mr. Fusco was a Vice President at Goldman Sachs Power, an affiliate of Goldman, Sachs & Co. Prior to joining Goldman Sachs, Mr. Fusco was employed by Pacific Gas and Electric Company or its affiliates in various engineering and management roles for approximately 13 years. Mr. Fusco obtained a Bachelor of Science degree in Mechanical Engineering from California State University, Sacramento. Mr. Fusco served as a director of Foster Wheeler Ltd., a global engineering and construction contractor and power equipment supplier, until February 2009 and Graphics Packaging Holdings, a paper and packaging company, until 2008.

John B. (Thad) Hill has served as our President and Chief Operating Officer since December 21, 2012. He previously served as our Executive Vice President and Chief Operating Officer from November 2010 to December 2012 and as our Executive Vice President and Chief Commercial Officer from September 2008 to November 2010. Prior to joining the Company, Mr. Hill most recently served as Executive Vice President of NRG Energy, Inc. since February 2006 and President of NRG Texas LLC since December 2006. Prior to joining NRG Energy, Inc., Mr. Hill was Executive Vice President of Strategy and Business Development at Texas Genco LLC from 2005 to 2006. From 1995 to 2005, Mr. Hill was with Boston Consulting Group, Inc., where he rose to Partner and Managing Director and led the North American energy practice, serving companies in the power and gas sector with a focus on commercial and strategic issues. Mr. Hill received his Bachelor of Arts degree from Vanderbilt University and a Master of Business Administration degree from the Amos Tuck School of Dartmouth College.

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

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

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

The remaining information required by this Item is incorporated herein by reference to the sections entitled "Board Meetings and Board Committee Information — Committees and Committee Charters" and " — Audit Committee," "Proposal 1 — Election of Directors," "Section 16(a) Beneficial Ownership Reporting Compliance," and "Corporate Governance Matters — Code of Conduct and Ethics" in our proxy statement for the 2014 annual meeting of stockholders to be held on May 14, 2014 (the "Proxy Statement").

Item 11. ***Executive Compensation***

Information required by this Item is incorporated herein by reference to to the sections entitled "Compensation Discussion and Analysis," "Executive Compensation," "Director Compensation" and "Board Meeting and Board Committee Information — Compensation Committee Interlocks and Insider Participation" in the Proxy Statement.

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

Information required by this Item is incorporated herein by reference to the sections entitled "Executive Compensation — Securities Authorized for Issuance Under Equity Compensation Plans" and "Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters" in the Proxy Statement.

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

Information required by this Item is incorporated herein by reference to the sections entitled "Certain Relationships and Related Transactions," "Corporate Governance Matters — Director Independence" and "Corporate Governance Matters — Business Relationships and Related Party Transactions Policy" in the Proxy Statement.

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

Information required by this Item is incorporated herein by reference to the sections entitled "Proposal 2 — To Ratify the Selection of PricewaterhouseCoopers LLP as the Company's Independent Registered Public Accounting Firm for the Year Ending December 31, 2014" in the Proxy Statement.

PART IV

Item 15. ***Exhibits, Financial Statement Schedule***

Exhibit Number	Description
2.1	Debtors' Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code (incorporated by reference to Exhibit 2.1 to Calpine's Current Report on Form 8-K, filed with the SEC on December 27, 2007).
2.2	Findings of Fact, Conclusions of Law, and Order Confirming Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code (incorporated by reference to Exhibit 2.2 to Calpine's Current Report on Form 8-K, filed with the SEC on December 27, 2007).
2.3	Purchase and Sale Agreement by and between Riverside Energy Center, LLC and Calpine Development Holdings, Inc., as Sellers and Public Service Company of Colorado, as Purchaser dated as of April 2, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed with the SEC on July 30, 2010).**,††
2.4	Purchase Agreement by and among Pepco Holdings, Inc., Conectiv, LLC, Conectiv Energy Holding Company, LLC and New Development Holdings, LLC dated as of April 20, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on July 8, 2010).**
3.1	Amended and Restated Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3.1 to Calpine's Current Report on Form 8-K, filed with the SEC on February 1, 2008).
3.2	Amended and Restated By-Laws of the Company (as amended through May 7, 2009) (incorporated by reference to Exhibit 3.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, filed with the SEC on July 31, 2009).
4.1	Indenture, dated October 21, 2009, between the Company and Wilmington Trust Company, as trustee, including form of 7.25% senior secured notes due 2017 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K, filed with the SEC on October 26, 2009).
4.2	Amended and Restated Indenture, dated May 25, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 8% Senior Secured Notes due 2019 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K, filed with the SEC on May 25, 2010).
4.3	Indenture, dated July 23, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.875% Senior Secured Notes due 2020 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K, filed with the SEC on July 23, 2010).
4.4	Indenture, dated October 22, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.50% Senior Secured Notes due 2021 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K, filed with the SEC on October 22, 2010).
4.5	Indenture, dated January 14, 2011, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.875% Senior Secured Notes due 2023 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K, filed with the SEC on January 14 , 2011).
4.6	Registration Rights Agreement, dated January 31, 2008, among the Company and each Participating Shareholder named therein (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on February 6, 2008).
4.7	First Supplemental Indenture dated as of April 26, 2011, among each of New Development Holdings, LLC, Calpine Mid-Atlantic Energy, LLC, Calpine Mid-Atlantic Operating, LLC, Calpine Bethlehem, LLC, Calpine New Jersey Generation, LLC, Calpine Mid-Atlantic Generation, LLC, Calpine Solar, LLC, Calpine Vineland Solar, LLC and Calpine Mid-Atlantic Marketing, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 21, 2009, providing for the issuance of 7.25% Senior Secured Notes due 2017 (incorporated by reference to Exhibit 4.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed with the SEC on April 29, 2011).

Exhibit Number	Description
4.8	First Supplemental Indenture dated as of April 26, 2011, among each of New Development Holdings, LLC, Calpine Mid-Atlantic Energy, LLC, Calpine Mid-Atlantic Operating, LLC, Calpine Bethlehem, LLC, Calpine New Jersey Generation, LLC, Calpine Mid-Atlantic Generation, LLC, Calpine Solar, LLC, Calpine Vineland Solar, LLC and Calpine Mid-Atlantic Marketing, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of May 25, 2010, providing for the issuance of 8.0% Senior Secured Notes due 2019 (incorporated by reference to Exhibit 4.3 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed with the SEC on April 29, 2011).
4.9	First Supplemental Indenture dated as of April 26, 2011, among each of New Development Holdings, LLC, Calpine Mid-Atlantic Energy, LLC, Calpine Mid-Atlantic Operating, LLC, Calpine Bethlehem, LLC, Calpine New Jersey Generation, LLC, Calpine Mid-Atlantic Generation, LLC, Calpine Solar, LLC, Calpine Vineland Solar, LLC and Calpine Mid-Atlantic Marketing, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of July 23, 2010, providing for the issuance of 7.875% Senior Secured Notes due 2020 (incorporated by reference to Exhibit 4.4 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed with the SEC on April 29, 2011).
4.10	First Supplemental Indenture dated as of April 26, 2011, among each of New Development Holdings, LLC, Calpine Mid-Atlantic Energy, LLC, Calpine Mid-Atlantic Operating, LLC, Calpine Bethlehem, LLC, Calpine New Jersey Generation, LLC, Calpine Mid-Atlantic Generation, LLC, Calpine Solar, LLC, Calpine Vineland Solar, LLC and Calpine Mid-Atlantic Marketing, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 22, 2010, providing for the issuance of 7.50% Senior Secured Notes due 2021 (incorporated by reference to Exhibit 4.5 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed with the SEC on April 29, 2011).
4.11	First Supplemental Indenture dated as of April 26, 2011, among each of New Development Holdings, LLC, Calpine Mid-Atlantic Energy, LLC, Calpine Mid-Atlantic Operating, LLC, Calpine Bethlehem, LLC, Calpine New Jersey Generation, LLC, Calpine Mid-Atlantic Generation, LLC, Calpine Solar, LLC, Calpine Vineland Solar, LLC and Calpine Mid-Atlantic Marketing, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of January 14, 2011, providing for the issuance of 7.875% Senior Secured Notes due 2023 (incorporated by reference to Exhibit 4.6 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed with the SEC on April 29, 2011).
4.12	Second Supplemental Indenture dated as of July 22, 2011, among each of Deer Park Energy Center LLC, Deer Park Holdings, LLC, Metcalf Energy Center, LLC, Metcalf Holdings, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 21, 2009, providing for the issuance of 7.25% Senior Secured Notes due 2017 (incorporated by reference to Exhibit 4.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 29, 2011).
4.13	Second Supplemental Indenture dated as of July 22, 2011, among each of Deer Park Energy Center LLC, Deer Park Holdings, LLC, Metcalf Energy Center, LLC, Metcalf Holdings, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of May 25, 2010, providing for the issuance of 8.0% Senior Secured Notes due 2019 (incorporated by reference to Exhibit 4.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 29, 2011).
4.14	Second Supplemental Indenture dated as of July 22, 2011, among each of Deer Park Energy Center LLC, Deer Park Holdings, LLC, Metcalf Energy Center, LLC, Metcalf Holdings, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of July 23, 2010, providing for the issuance of 7.875% Senior Secured Notes due 2020 (incorporated by reference to Exhibit 4.3 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 29, 2011).
4.15	Second Supplemental Indenture dated as of July 22, 2011, among each of Deer Park Energy Center LLC, Deer Park Holdings, LLC, Metcalf Energy Center, LLC, Metcalf Holdings, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 22, 2010, providing for the issuance of 7.50% Senior Secured Notes due 2021 (incorporated by reference to Exhibit 4.4 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 29, 2011).
4.16	Second Supplemental Indenture dated as of July 22, 2011, among each of Deer Park Energy Center LLC, Deer Park Holdings, LLC, Metcalf Energy Center, LLC, Metcalf Holdings, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of January 14, 2011, providing for the issuance of 7.875% Senior Secured Notes due 2023 (incorporated by reference to Exhibit 4.5 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 29, 2011).

Exhibit Number	Description
4.17	Third Supplemental Indenture dated as of August 20, 2012, among each of Calpine Energy Services GP, LLC and Calpine Energy Services LP, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 21, 2009, providing for the issuance of 7.25% Senior Secured Notes due 2017 (incorporated by reference to Exhibit 4.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, filed with the SEC on November 6, 2012).
4.18	Third Supplemental Indenture dated as of August 20, 2012, among each of Calpine Energy Services GP, LLC and Calpine Energy Services LP, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of May 25, 2010, providing for the issuance of 8.0% Senior Secured Notes due 2019 (incorporated by reference to Exhibit 4.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, filed with the SEC on November 6, 2012).
4.19	Third Supplemental Indenture dated as of August 20, 2012, among each of Calpine Energy Services GP, LLC and Calpine Energy Services LP, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of July 23, 2010, providing for the issuance of 7.875% Senior Secured Notes due 2020 (incorporated by reference to Exhibit 4.3 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, filed with the SEC on November 6, 2012).
4.20	Third Supplemental Indenture dated as of August 20, 2012, among each of Calpine Energy Services GP, LLC and Calpine Energy Services LP, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 22, 2010, providing for the issuance of 7.50% Senior Secured Notes due 2021 (incorporated by reference to Exhibit 4.4 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, filed with the SEC on November 6, 2012).
4.21	Third Supplemental Indenture dated as of August 20, 2012, among each of Calpine Energy Services GP, LLC and Calpine Energy Services LP, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of January 14, 2011, providing for the issuance of 7.875% Senior Secured Notes due 2023 (incorporated by reference to Exhibit 4.5 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, filed with the SEC on November 6, 2012).
4.22	Fourth Supplemental Indenture dated as of November 26, 2012, among each of South Point Holdings, LLC, South Point Energy Center, LLC, Broad River Energy LLC, South Point OL-1, LLC, South Point OL-2, LLC, South Point OL-3, LLC, South Point OL-4, LLC, Broad River OL-1, LLC, Broad River OL-2, LLC, Broad River OL-3, LLC and Broad River OL-4, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 21, 2009, providing for the issuance of 7.25% Senior Secured Notes due 2017 (incorporated by reference to Exhibit 4.24 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2012, filed with the SEC on February 13, 2013).
4.23	Fourth Supplemental Indenture dated as of November 26, 2012, among each of South Point Holdings, LLC, South Point Energy Center, LLC, Broad River Energy LLC, South Point OL-1, LLC, South Point OL-2, LLC, South Point OL-3, LLC, South Point OL-4, LLC, Broad River OL-1, LLC, Broad River OL-2, LLC, Broad River OL-3, LLC and Broad River OL-4, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of May 25, 2010, providing for the issuance of 8.0% Senior Secured Notes due 2019 (incorporated by reference to Exhibit 4.25 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2012, filed with the SEC on February 13, 2013).
4.24	Fourth Supplemental Indenture dated as of November 26, 2012, among each of South Point Holdings, LLC, South Point Energy Center, LLC, Broad River Energy LLC, South Point OL-1, LLC, South Point OL-2, LLC, South Point OL-3, LLC, South Point OL-4, LLC, Broad River OL-1, LLC, Broad River OL-2, LLC, Broad River OL-3, LLC and Broad River OL-4, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of July 23, 2010, providing for the issuance of 7.875% Senior Secured Notes due 2020 (incorporated by reference to Exhibit 4.26 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2012, filed with the SEC on February 13, 2013).
4.25	Fourth Supplemental Indenture dated as of November 26, 2012, among each of South Point Holdings, LLC, South Point Energy Center, LLC, Broad River Energy LLC, South Point OL-1, LLC, South Point OL-2, LLC, South Point OL-3, LLC, South Point OL-4, LLC, Broad River OL-1, LLC, Broad River OL-2, LLC, Broad River OL-3, LLC and Broad River OL-4, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 22, 2010, providing for the issuance of 7.50% Senior Secured Notes due 2021 (incorporated by reference to Exhibit 4.27 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2012, filed with the SEC on February 13, 2013).

Exhibit Number	Description
4.26	Fourth Supplemental Indenture dated as of November 26, 2012, among each of South Point Holdings, LLC, South Point Energy Center, LLC, Broad River Energy LLC, South Point OL-1, LLC, South Point OL-2, LLC, South Point OL-3, LLC, South Point OL-4, LLC, Broad River OL-1, LLC, Broad River OL-2, LLC, Broad River OL-3, LLC and Broad River OL-4, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of January 14, 2011, providing for the issuance of 7.875% Senior Secured Notes due 2023 (incorporated by reference to Exhibit 4.28 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2012, filed with the SEC on February 13, 2013).
4.27	Indenture dated as of October 31, 2013, for the Senior Secured Notes due 2022 among each of Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K, filed with the SEC on October 31, 2013).
4.28	Indenture dated as of October 31, 2013, for the Senior Secured Notes due 2024 among each of Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.2 to Calpine's Current Report on Form 8-K, filed with the SEC on October 31, 2013).
4.29	Fifth Supplemental Indenture dated as of October 30, 2013 among each of Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee under the indenture, dated as of October 21, 2009, providing for the issuance of 7.25% Senior Secured Notes due 2017 (incorporated by reference to Exhibit 4.3 to Calpine's Current Report on Form 8-K, filed with the SEC on October 31, 2013).
10.1	Financing Agreements.
10.1.1.5	Credit Agreement, dated as of December 10, 2010, among Calpine Corporation, Goldman Sachs Bank USA, as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, the lenders party thereto and other parties thereto (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on December 13, 2010).
10.1.1.6	Credit Agreement, dated March 9, 2011 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, Citibank, N.A., Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc., as co-documentation agents and Goldman Sachs Bank USA as syndication agent (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on March 10, 2011).
10.1.1.7	Amended and Restated Guarantee and Collateral Agreement, dated as of December 10, 2010, made by the Company and certain of the Company's subsidiaries party thereto in favor of Goldman Sachs Credit Partners, L.P., as collateral agent (incorporated by reference to Exhibit 10.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 29, 2011).
10.1.1.8	Credit Agreement, dated October 9, 2012 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 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on October 10, 2012).
10.1.1.9	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, Citibank, N.A., Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc., as co-documentation agents and Goldman Sachs Bank USA as syndication agent (incorporated by reference to Exhibit 10.9 to Calpine's 10-Q for the quarter ended March 31, 2013, filed with the SEC on May 2, 2013).
10.1.1.10	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 (incorporated by reference to Exhibit 10.10 to Calpine's 10-Q for the quarter ended March 31, 2013, filed with the SEC on May 2, 2013).
10.1.1.11	Credit Agreement, dated May 3, 2013 among Calpine Construction Finance Company as borrower and the lenders party thereto, and Goldman Sachs Lending Partners, LLC ("GSLP") as administrative agent and as collateral agent, CoBank ACB, ING Capital LLC., Royal Bank of Canada, and The Royal Bank of Scotland PLC as co-documentation agents, GSLP, Deutsche Bank Securities Inc., Credit Suisse Securities (USA) LLC, Merrill Lynch, Pierce Fenner and Smith Incorporated and Union Bank, N.A., as joint lead arrangers, joint bookrunners and co-syndication agents, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the SEC on May 3, 2013).

Exhibit Number	Description
10.1.1.12	Amendment No. 1 to the December 10, 2010 Credit Agreement, dated as of June 27, 2013, among Calpine Corporation, as borrower, Goldman Sachs Bank USA, as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the SEC on July 1, 2013).
10.2	Management Contracts or Compensatory Plans, Contracts or Arrangements.
10.2.1.1	Employment Agreement, dated August 10, 2008, between the Company and Jack A. Fusco (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on August 12, 2008).†
10.2.1.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (Jack A. Fusco) (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K, filed with the SEC on August 12, 2008).†
10.2.1.3	Non-Qualified Stock Option Agreement between the Company and Jack Fusco, dated August 11, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on August 17, 2010).†
10.2.1.4	Amendment to the Executive Employment Agreement between the Company and Jack A. Fusco, dated December 21, 2012 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on December 26, 2012).†
10.2.1.5	Restricted Stock Award Agreement between the Company and Jack A. Fusco, dated December 21, 2012 (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K, filed with the SEC on December 26, 2012).†
10.2.2	Letter Agreement, dated December 17, 2008, between the Company and Zamir Rauf (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on December 19, 2008).†
10.2.3.1	Letter Agreement, dated September 1, 2008, between the Company and John B. Hill (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on September 4, 2008).†
10.2.3.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (John B. Hill) (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K, filed with the SEC on September 4, 2008).†
10.2.3.3	Non-Qualified Stock Option Agreement between the Company and John B. (Thad) Hill, dated August 11, 2010 (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K, filed with the SEC on August 17, 2010).†
10.2.3.4	Non-Qualified Stock Option Agreement between the Company and John B. (Thad) Hill, dated November 3, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on November 8, 2010).†
10.2.3.5	Amendment to the Letter Agreement between the Company and John B. (Thad) Hill, dated December 21, 2012 (incorporated by reference to Exhibit 10.3 to Calpine's Current Report on Form 8-K, filed with the SEC on December 26, 2012).†
10.2.3.6	Restricted Stock Award Agreement between the Company and John B. (Thad) Hill, dated December 21, 2012 (incorporated by reference to Exhibit 10.4 to Calpine's Current Report on Form 8-K, filed with the SEC on December 26, 2012).†
10.2.3.7	Employment Agreement, dated November 6, 2013, between the Company and John B. (Thad) Hill.*†
10.2.4.1	Employment Agreement, dated August 11, 2008, between the Company and W. Thaddeus Miller (incorporated by reference to Exhibit 10.2.7 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed with the SEC on November 7, 2008).†
10.2.4.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (Thaddeus Miller) (incorporated by reference to Exhibit 4.4 to Calpine's Registration Statement on Form S-8 (Registration No. 333-153860) filed with the SEC on October 6, 2008).†
10.2.4.3	Non-Qualified Stock Option Agreement between the Company and W. Thaddeus Miller, dated August 11, 2010 (incorporated by reference to Exhibit 10.3 to Calpine's Current Report on Form 8-K, filed with the SEC on August 17, 2010).†

Exhibit Number	Description
10.2.4.4	Amendment to the Executive Employment Agreement between the Company and W. Thaddeus Miller, dated December 21, 2012 (incorporated by reference to Exhibit 10.5 to Calpine's Current Report on Form 8-K, filed with the SEC on December 26, 2012).†
10.2.4.5	Restricted Stock Award Agreement between the Company and W. Thaddeus Miller, dated December 21, 2012 (incorporated by reference to Exhibit 10.6 to Calpine's Current Report on Form 8-K filed, with the SEC on December 26, 2012).†
10.2.5	Calpine Corporation U.S. Severance Program (incorporated by reference to Exhibit 10.2.5 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 25, 2010).†
10.2.6	Calpine Corporation 2010 Calpine Incentive Plan (incorporated by reference to Exhibit 10.6 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed with the SEC on July 30, 2010).†
10.2.7	Calpine Corporation 2009 Calpine Incentive Plan (incorporated by reference to Exhibit 10.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 8, 2009).†
10.2.7.2	Form of Non-Qualified Stock Option Agreement (Pursuant to the 2008 Equity Incentive Plan) (incorporated by reference to Exhibit 10.4.3 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.2.7.3	Form of Restricted Stock Agreement (Pursuant to the 2008 Equity Incentive Plan) (incorporated by reference to Exhibit 10.4.4 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.2.8	The Amended and Restated Calpine Corporation 2008 Director Incentive Plan (incorporated by reference to Annex A to Calpine's Definitive Proxy Statement on Schedule 14A filed with the SEC on April 5, 2010).†
10.2.10	Letter Agreement, dated December 30, 2008, between the Company and Jim D. Deidiker (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on January 8, 2009).†
10.2.11	Calpine Corporation Amended and Restated Change in Control and Severance Benefits Plan (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on November 8, 2013).†
10.2.12	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).†
10.2.13	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).†
10.2.14	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).†
10.2.15	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).†
10.2.16	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). †
10.2.17	Form of Performance Share Unit 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 10.6 to Calpine's Current Report on Form 8-K, filed with the SEC on March 4, 2013).†
10.2.18	Amended and Restated Restricted Stock Award Agreement between the Company and Jack A. Fusco, dated February 28, 2013 (incorporated by reference to Exhibit 10.7 to Calpine's 10-Q for the quarter ended March 31, 2013, filed with the SEC on May 2, 2013).†

Exhibit Number	Description
10.2.19	Amended and Restated Restricted Stock Award Agreement between the Company and W. Thaddeus Miller, dated February 28, 2013 (incorporated by reference to Exhibit 10.8 to Calpine's 10-Q for the quarter ended March 31, 2013, filed with the SEC on May 2, 2013).†
10.2.20	Amended and Restated Calpine Corporation Equity Incentive Plan (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on May 10, 2013).†
18.1	Letter of preferability regarding change in accounting principle from PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm (incorporated by reference to Exhibit 18.1 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 25, 2010).
21.1	Subsidiaries of the Company.*
23.1	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.*
24.1	Power of Attorney of Officers and Directors of Calpine Corporation (set forth on the signature pages of this Form 10-K).*
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 Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.‡
101.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.*

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* Filed herewith.

‡ Furnished herewith.

† Management contract or compensatory plan, contract or arrangement.

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

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

SIGNATURES

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

CALPINE CORPORATION

By: /s/ ZAMIR RAUF

Zamir Rauf
Executive Vice President and Chief Financial Officer

Date: February 12, 2014

POWER OF ATTORNEY

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

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

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

Signature	Title	Date
/s/ JACK A. FUSCO Jack A. Fusco	Chief Executive Officer and Director (principal executive officer)	February 12, 2014
/s/ ZAMIR RAUF Zamir Rauf	Executive Vice President and Chief Financial Officer (principal financial officer)	February 12, 2014
/s/ JIM D. DEIDIKER Jim D. Deidiker	Chief Accounting Officer (principal accounting officer)	February 12, 2014
/s/ FRANK CASSIDY Frank Cassidy	Director	February 12, 2014
/s/ ROBERT C. HINCKLEY Robert C. Hinckley	Director	February 12, 2014
/s/ MICHAEL W. HOFMANN Michael W. Hofmann	Director	February 12, 2014
/s/ DAVID C. MERRITT David C. Merritt	Director	February 12, 2014
/s/ W. BENJAMIN MORELAND W. Benjamin Moreland	Director	February 12, 2014
/s/ ROBERT MOSBACHER, JR. Robert Mosbacher, Jr.	Director	February 12, 2014
/s/ DENISE M. O'LEARY Denise M. O’Leary	Director	February 12, 2014
/s/ J. STUART RYAN J. Stuart Ryan	Director	February 12, 2014

CALPINE CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2013

Report of Independent Registered Public Accounting Firm

To the Board of Directors
and Stockholders of Calpine Corporation

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)-1 present fairly, in all material respects, the financial position of Calpine Corporation and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)-2 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting, appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 12, 2014

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2013, 2012 and 2011
(in millions, except share and per share amounts)

	2013	2012	2011
Operating revenues:			
Commodity revenue	$ 6,374	$ 5,417	$ 6,753
Unrealized mark-to-market gain (loss)	(86)	48	35
Other revenue	13	13	12
Operating revenues	6,301	5,478	6,800
Operating expenses:			
Fuel and purchased energy expense:			
Commodity expense	3,808	2,894	4,299
Unrealized mark-to-market (gain) loss	(72)	130	60
Fuel and purchased energy expense	3,736	3,024	4,359
Plant operating expense	895	922	904
Depreciation and amortization expense	609	562	550
Sales, general and other administrative expense	136	140	131
Other operating expenses	81	78	77
Total operating expenses	5,457	4,726	6,021
(Gain) on sale of assets, net	—	(222)	—
(Income) from unconsolidated investments in power plants	(30)	(28)	(21)
Income from operations	874	1,002	800
Interest expense	696	736	760
Loss on interest rate derivatives	—	14	145
Interest (income)	(6)	(11)	(9)
Debt extinguishment costs	144	30	94
Other (income) expense, net	20	15	21
Income (loss) before income taxes	20	218	(211)
Income tax expense (benefit)	2	19	(22)
Net income (loss)	18	199	(189)
Net income attributable to the noncontrolling interest	(4)	—	(1)
Net income (loss) attributable to Calpine	$ 14	$ 199	$ (190)
Basic earnings (loss) per common share attributable to Calpine:			
Weighted average shares of common stock outstanding (in thousands)	440,666	467,752	485,381
Net income (loss) per common share attributable to Calpine — basic	$ 0.03	$ 0.43	$ (0.39)
Diluted earnings (loss) per common share attributable to Calpine:			
Weighted average shares of common stock outstanding (in thousands)	444,773	471,343	485,381
Net income (loss) per common share attributable to Calpine — diluted	$ 0.03	$ 0.42	$ (0.39)

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	2013	2012	2011
Net income (loss)	$ 18	$ 199	$ (189)
Cash flow hedging activities:			
Gain (loss) on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income (loss)	35	(61)	(69)
Reclassification adjustment for (gain) loss on cash flow hedges realized in net income (loss)	51	(20)	(25)
Unrealized actuarial gains (losses) arising during period	4	(1)	(3)
Foreign currency translation gain (loss)	(10)	3	(1)
Income tax (expense) benefit	(3)	9	45
Other comprehensive income (loss)	77	(70)	(53)
Comprehensive income (loss)	95	129	(242)
Comprehensive (income) loss attributable to the noncontrolling interest	(13)	6	13
Comprehensive income (loss) attributable to Calpine	$ 82	$ 135	$ (229)

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
December 31, 2013 and 2012
(in millions, except share and per share amounts)

	2013	2012
ASSETS		
Current assets:		
Cash and cash equivalents ($242 and $109 attributable to VIEs)	$ 941	$ 1,284
Accounts receivable, net of allowance of $5 and $6	552	437
Margin deposits and other prepaid expense	309	244
Restricted cash, current ($100 and $53 attributable to VIEs)	203	193
Derivative assets, current	445	339
Inventory and other current assets	406	335
Total current assets	2,856	2,832
Property, plant and equipment, net ($4,191 and $4,192 attributable to VIEs)	12,995	13,005
Restricted cash, net of current portion ($68 and $59 attributable to VIEs)	69	60
Investments in power plants	93	81
Long-term derivative assets	105	98
Other assets	441	473
Total assets	$ 16,559	$ 16,549
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 462	$ 382
Accrued interest payable	162	180
Debt, current portion ($140 and $39 attributable to VIEs)	204	115
Derivative liabilities, current	451	357
Income taxes payable	7	11
Other current liabilities	245	273
Total current liabilities	1,531	1,318
Debt, net of current portion ($2,923 and $2,660 attributable to VIEs)	10,908	10,635
Long-term derivative liabilities	243	293
Other long-term liabilities	309	247
Total liabilities	12,991	12,493
Commitments and contingencies (see Note 15)		
Stockholders' equity:		
Preferred stock, $0.001 par value per share; authorized 100,000,000 shares, none issued and outstanding at December 31, 2013 and 2012	—	—
Common stock, $0.001 par value per share; authorized 1,400,000,000 shares, 497,841,056 shares issued and 429,038,988 shares outstanding at December 31, 2013, and 492,495,100 shares issued and 457,048,970 shares outstanding at December 31, 2012	1	1
Treasury stock, at cost, 68,802,068 and 35,446,130 shares, respectively	(1,230)	(594)
Additional paid-in capital	12,389	12,335
Accumulated deficit	(7,486)	(7,500)
Accumulated other comprehensive loss	(160)	(228)
Total Calpine stockholders' equity	3,514	4,014
Noncontrolling interest	54	42
Total stockholders' equity	3,568	4,056
Total liabilities and stockholders' equity	$ 16,559	$ 16,549

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Stockholders' Equity
Balance, December 31, 2010	$ 1	$ (5)	$ 12,281	$ (7,509)	$ (125)	$ 26	$ 4,669
Treasury stock transactions	—	(120)	—	—	—	—	(120)
Stock-based compensation expense	—	—	24	—	—	—	24
Other	—	—	—	—	—	33	33
Net income (loss)	—	—	—	(190)	—	1	(189)
Other comprehensive loss	—	—	—	—	(39)	(14)	(53)
Balance, December 31, 2011	$ 1	$ (125)	$ 12,305	$ (7,699)	$ (164)	$ 46	$ 4,364
Treasury stock transactions	—	(469)	—	—	—	—	(469)
Stock-based compensation expense	—	—	25	—	—	—	25
Option exercises	—	—	5	—	—	—	5
Other	—	—	—	—	—	2	2
Net income	—	—	—	199	—	—	199
Other comprehensive loss	—	—	—	—	(64)	(6)	(70)
Balance, December 31, 2012	$ 1	$ (594)	$ 12,335	$ (7,500)	$ (228)	$ 42	$ 4,056
Treasury stock transactions	—	(636)	—	—	—	—	(636)
Stock-based compensation expense	—	—	34	—	—	—	34
Option exercises	—	—	20	—	—	—	20
Other	—	—	—	—	—	(1)	(1)
Net income	—	—	—	14	—	4	18
Other comprehensive income	—	—	—	—	68	9	77
Balance, December 31, 2013	$ 1	$ (1,230)	$ 12,389	$ (7,486)	$ (160)	$ 54	$ 3,568

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	2013	2012	2011
Cash flows from operating activities:			
Net income (loss)	$ 18	$ 199	$ (189)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization expense(1)	654	605	587
Debt extinguishment costs	43	—	82
Deferred income taxes	14	1	(21)
(Gain) loss on sale of power plants and other, net	4	(212)	13
Unrealized mark-to-market activity, net	12	(72)	(30)
(Income) from unconsolidated investments in power plants	(30)	(28)	(21)
Return on unconsolidated investments in power plants	25	24	6
Stock-based compensation expense	36	25	24
Other	(3)	1	6
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable	(113)	159	74
Derivative instruments, net	(7)	(52)	15
Other assets	(148)	(57)	1
Accounts payable and accrued expenses	(1)	(86)	28
Settlement of non-hedging interest rate swaps	—	156	189
Other liabilities	45	(10)	11
Net cash provided by operating activities	549	653	775
Cash flows from investing activities:			
Purchases of property, plant and equipment	(575)	(637)	(683)
Proceeds from sale of power plants, interests and other	1	825	13
Purchase of Bosque Energy Center, net of cash	—	(432)	—
Return of investment from unconsolidated investments in power plants	2	5	—
Settlement of non-hedging interest rate swaps	—	(156)	(189)
(Increase) decrease in restricted cash	(18)	(59)	54
Purchases of deferred transmission credits	—	(12)	(31)
Other	(3)	(4)	—
Net cash used in investing activities	(593)	(470)	(836)
Cash flows from financing activities:			
Borrowings under First Lien Term Loans	390	835	1,657
Repayments of First Lien Term Loans	(25)	(19)	—
Borrowings from CCFC Term Loans	1,197	—	—
Repayments under CCFC Term Loans	(6)	—	—
Repayment of CCFC Notes	(1,000)	—	—
Repayments on NDH Project Debt	—	—	(1,283)
Borrowings under First Lien Notes	1,234	—	1,200
Repayments of First Lien Notes	(1,550)	(590)	—
Repayments on First Lien Credit Facility	—	—	(1,195)
Borrowings from project financing, notes payable and other	182	389	327
Repayments of project financing, notes payable and other	(66)	(289)	(550)
Capital contributions from noncontrolling interest holder	—	—	33
Financing costs	(53)	(20)	(81)
Stock repurchases	(623)	(463)	(119)
Proceeds from exercises of stock options	20	5	—
Other	1	1	(3)
Net cash used in financing activities	(299)	(151)	(14)
Net increase (decrease) in cash and cash equivalents	(343)	32	(75)
Cash and cash equivalents, beginning of period	1,284	1,252	1,327
Cash and cash equivalents, end of period	$ 941	$ 1,284	$ 1,252

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)
(in millions)

	2013	2012	2011
Cash paid during the period for:			
Interest, net of amounts capitalized	$ 672	$ 719	$ 656
Income taxes	$ 24	$ 16	$ 18
Supplemental disclosure of non-cash investing activities:			
Change in capital expenditures included in accounts payable	$ 27	$ 19	$ (24)
Other non-cash additions to property, plant and equipment	$ —	$ 13	$ —

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the Years Ended December 31, 2013, 2012 and 2011

1. Organization and Operations

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 natural gas and fuel oil as fuel for our power plants and engage in related natural gas transportation and storage transactions. We also purchase electric transmission rights to deliver power to our customers. Additionally, consistent with our Risk Management Policy, we enter into natural gas and power physical and financial contracts to hedge certain business risks and optimize our portfolio of power plants.

2. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

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

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

Reclassifications — Certain reclassifications have been made to our Consolidated Balance Sheet as of December 31, 2012, and our Statements of Comprehensive Income (Loss), Stockholders' Equity and Cash Flows for the years ended December 31, 2012 and 2011, to conform to the current year presentation. Our reclassifications are summarized as follows:

- We have reclassified \$(6) million and \$(14) million related to our noncontrolling interest's portion of cash flow hedge losses, net of tax, in OCI to comprehensive income (loss) attributable to the noncontrolling interest for the years ended December 31, 2012 and 2011, respectively, on our Consolidated Statements of Comprehensive Income (Loss). This reclassification is also reflected in the AOCI and noncontrolling interest balances on our Consolidated Balance Sheet as of December 31, 2012 and on our Consolidated Statements of Stockholders' Equity for the years ended December 31, 2012 and 2011.

- We have reclassified \$5 million and nil on our Consolidated Statements of Cash Flows for the years ended December 31, 2012 and 2011, respectively, to separately report proceeds from the exercises of stock options, previously reflected in other cash flows used in financing activities.

Jointly-Owned Plants — Certain of our subsidiaries own undivided interests in jointly-owned plants. These plants are maintained and operated pursuant to their joint ownership participation and operating agreements. We are responsible for our subsidiaries' share of operating costs and direct expenses and include our proportionate share of the facilities and related revenues and direct expenses in these jointly-owned plants in the corresponding balance sheet and income statement captions of our Consolidated Financial Statements. The following table summarizes our proportionate ownership interest in jointly-owned power plants:

As of December 31, 2013	Ownership Interest	Property, Plant & Equipment	Accumulated Depreciation	Construction in Progress
	(in millions, except percentages)			
Freestone Energy Center...	75.0%	$ 393	$ (135)	$ —
Hidalgo Energy Center......	78.5%	$ 255	$ (93)	$ —

Use of Estimates in Preparation of Financial Statements

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

Fair Value of Financial Instruments and Derivatives

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

Concentrations of Credit Risk

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

Our counterparties primarily consist of three categories of entities who participate in the wholesale energy markets:

- financial institutions and trading companies;
- regulated utilities, municipalities, cooperatives, ISOs and other retail power suppliers; and
- oil, natural gas, chemical and other energy-related industrial companies.

We have concentrations of credit risk with a few of our commercial customers relating to our sales of power, steam and hedging and optimization activities. We have exposure to trends within the energy industry, including declines in the creditworthiness of our counterparties for our commodity and derivative transactions. Currently, certain of our marketing counterparties within the energy industry have below investment grade credit ratings. Our risk control group manages counterparty credit risk and monitors our net exposure with each counterparty on a daily basis. The analysis is performed on a mark-to-market basis using forward curves. The net exposure is compared against a counterparty credit risk threshold which is determined based on each counterparty's credit rating and evaluation of their financial statements. We utilize these thresholds to determine the need for additional collateral or restriction of activity with the counterparty. We believe that our credit policies and portfolio of transactions adequately monitor and diversify our credit risk, and currently our counterparties are performing and financially settling timely according to their respective agreements.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. We have certain project finance facilities and lease agreements that require us to establish and maintain segregated cash accounts, which have been pledged as security in favor of the lenders under such project finance facilities, and the use of certain cash balances on deposit in such accounts is limited, at least temporarily, to the operations of the respective projects. At December 31, 2013 and 2012, we had cash and cash equivalents of $292 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 Balance Sheets and Statements of Cash Flows.

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

	2013			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	35	20	55	32	14	46
Security/project/insurance	151	6	157	101	3	104
Other	3	2	5	49	2	51
Total	$ 203	$ 69	$ 272	$ 193	$ 60	$ 253

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(1) At December 31, 2013 and 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.

Accounts Receivable and Payable

Accounts receivable and payable represent amounts due from customers and owed to vendors, respectively. Accounts receivable are recorded at invoiced amounts, net of reserves and allowances, and do not bear interest. Receivable balances greater than 30 days past due are individually reviewed for collectability, and if deemed uncollectible, are charged off against the allowance accounts after all means of collection have been exhausted and the potential for recovery is considered remote. We use our best estimate to determine the required allowance for doubtful accounts based on a variety of factors, including the length of time receivables are past due, economic trends and conditions affecting our customer base, significant one-time events and historical write-off experience. Specific provisions are recorded for individual receivables when we become aware of a customer's inability to meet its financial obligations. We review the adequacy of our reserves and allowances quarterly.

The accounts receivable and payable balances also include settled but unpaid amounts relating to our marketing, hedging and optimization activities. Some of these receivables and payables with individual counterparties are subject to master netting arrangements whereby we legally have a right of offset and settle the balances net. However, for balance sheet presentation purposes and to be consistent with the way we present the majority of amounts related to marketing, hedging and optimization activities on our Consolidated Statements of Operations, we present our receivables and payables on a gross basis. We do not have any significant off balance sheet credit exposure related to our customers.

Inventory

At December 31, 2013 and 2012, we had inventory of $364 million and $301 million, respectively. Inventory primarily consists of spare parts, stored natural gas and fuel oil, environmental products 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.

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 previously subject to first priority liens under our First Lien Notes, First Lien Term Loans and Corporate Revolving Facility as collateral under certain of our power and natural gas agreements. These agreements qualify as "eligible commodity hedge agreements" under our First Lien Notes, First Lien Term Loans and Corporate Revolving Facility. The first priority liens have been granted in order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to our counterparties under such agreements. The counterparties under such agreements would share the benefits of the collateral subject to such first priority liens ratably with the lenders under our First Lien Notes, First Lien Term Loans and Corporate Revolving Facility. Our interest rate swap agreements relate to hedges of certain of our project financings collateralized by first priority liens on the underlying assets. See Note 9 for a further discussion on our amounts and use of collateral.

Deferred Financing Costs

Costs incurred related to the issuance of debt instruments are deferred and amortized over the term of the related debt using a method that approximates the effective interest rate method. However, when the timing of debt transactions involve contemporaneous exchanges of cash between us and the same creditor(s) in connection with the issuance of a new debt obligation and satisfaction of an existing debt obligation, deferred financing costs are accounted for depending on whether the transaction qualifies as an extinguishment or modification, which requires us to either write-off the original deferred financing costs and capitalize the new issuance costs, or continue to amortize the original deferred financing costs and immediately expense the new issuance costs.

Property, Plant and Equipment, Net

Property, plant, and equipment items are recorded at cost. We capitalize costs incurred in connection with the construction of power plants, the development of geothermal properties and the refurbishment of major turbine generator equipment. When capital improvements to leased power plants meet our capitalization criteria they are capitalized as leasehold improvements and amortized over the shorter of the term of the lease or the economic life of the capital improvement. We expense maintenance when the service is performed for work that does not meet our capitalization criteria. Our current capital expenditures at our Geysers Assets are those incurred for proven reserves and reservoir replenishment (primarily water injection), pipeline and power generation assets and drilling of "development wells" as all drilling activity has been performed within the known boundaries of the steam reservoir. We have capitalized costs incurred during ownership consisting of additions, certain replacements or repairs when the repairs appreciably extend the life, increase the capacity or improve the efficiency or safety of the property. Such costs are expensed when they do not meet the above criteria. We purchased our Geysers Assets as a proven steam reservoir and accounted for the assets under purchase accounting. All well costs, except well workovers and routine repairs and maintenance, have been capitalized since our purchase date.

We depreciate our assets under the straight-line method over the shorter of their estimated useful lives or lease term. For our natural gas-fired power plants, we assume an estimated salvage value which approximates 10% of the depreciable cost basis where we own the power plant or have a favorable option to purchase the power plant or take ownership of the power plant at conclusion of the lease term and approximately 0.15% of the depreciable costs basis for rotable equipment. For our Geysers Assets, we typically assume no salvage values. We use the component depreciation method for our natural gas-fired power plant rotable parts and our information technology equipment and the composite depreciation method for most of all of the other natural gas-fired power plant asset groups and Geysers Assets.

Generally, upon normal retirement of assets under the composite depreciation method, the costs of such assets are retired against accumulated depreciation and no gain or loss is recorded. For the retirement of assets under the component depreciation method, generally, the costs and related accumulated depreciation of such assets are removed from our Consolidated Balance Sheets and a gain or loss is recorded as plant operating expense.

Impairment Evaluation of Long-Lived Assets (Including Intangibles and Investments)

We evaluate our long-lived assets, such as property, plant and equipment, equity method investments and definite-lived intangible assets for impairment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Equipment assigned to each power plant is not evaluated for impairment separately; instead, we evaluate our operating power plants and related equipment as a whole unit. When we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities for long-lived assets that are expected to be held and used. If we determine that the undiscounted cash flows from an asset to be held and used are less than the carrying amount of the asset, or if we have classified an asset as held for sale, we must estimate fair value to determine the amount of any impairment loss. All construction and development projects are reviewed for impairment whenever there is an indication of potential reduction in fair value. If it is determined that a construction or development project is no longer probable of completion and the capitalized costs will not be recovered through future operations, the carrying value of the project will be written down to its fair value.

In order to estimate future cash flows, we consider historical cash flows, existing and future contracts and PPAs and changes in the market environment and other factors that may affect future cash flows. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our earnings forecasts). The use of this method involves inherent uncertainty. We use our best estimates in making these evaluations and consider various factors, including forward price curves for power and fuel costs and forecasted operating costs. However, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

When we determine that our assets meet the assets held-for-sale criteria, they are reported at the lower of their carrying amount or fair value less the cost to sell. We are also required to evaluate our equity method investments to determine whether or not they are impaired when the value is considered an “other than a temporary” decline in value.

Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. We will also discount the estimated future cash flows associated with the asset using a single interest rate representative of the risk involved with such an investment including contract terms, tenor and credit risk of counterparties. We may also consider prices of similar assets, consult with brokers, or employ other valuation techniques. We use our best estimates in making these evaluations and consider various factors, including forward price curves for power and fuel costs and forecasted operating costs. However, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

During 2013, 2012 and 2011, we did not record any material impairment losses.

Asset Retirement Obligation

We record all known asset retirement obligations for which the liability’s fair value can be reasonably estimated. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. At December 31, 2013 and 2012, our asset retirement obligation liabilities were $44 million and $38 million, respectively, primarily relating to land leases upon which our power plants are built and the requirement that the property meet specific conditions upon its return.

Revenue Recognition

Our operating revenues are comprised of the following:

- power and steam revenue consisting of fixed and variable capacity payments, which are not related to generation including capacity payments received from PJM capacity auctions, variable payments for power and steam, which are related to generation, host steam and RECs from our Geysers Assets, other revenues such as RMR Contracts, resource adequacy and certain ancillary service revenues and realized settlements from our marketing, hedging and optimization activities;
- unrealized revenues from derivative instruments as a result of our marketing, hedging and optimization activities; and
- other service revenues.

Power and Steam

Physical Commodity Contracts — We recognize revenue primarily from the sale of power and steam thermal energy for sale to our customers for use in industrial or other heating operations upon transmission and delivery to the customer.

We routinely enter into physical commodity contracts for sales of our generated power to manage risk and capture the value inherent in our generation. Such contracts often meet the criteria of a derivative but are generally eligible for and designated under the normal purchase normal sale exemption. We apply lease accounting to contracts that meet the definition of a lease and accrual accounting treatment to those contracts that are either exempt from derivative accounting or do not meet the definition of a derivative instrument. Additionally, we determine whether the financial statement presentation of revenues should be on a gross or net basis.

With respect to our physical executory contracts, where we act as a principal, we take title of the commodities and assume the risks and rewards of ownership by receiving the natural gas and using the natural gas in our operations to generate and deliver the power. Where we act as principal, we record settlement of our physical commodity contracts on a gross basis. Where we do not take title of the commodities but receive a net variable payment to convert natural gas into power and steam in a tolling operation, we record the variable payment as revenue but do not record any fuel and purchased energy expense.

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

Realized and Unrealized Revenues from Commodity Derivative Instruments

Realized Settlements of Commodity Derivative Instruments — The realized value of power commodity sales and purchase contracts that are net settled or settled as gross sales and purchases, but could have been net settled, are reflected on a net basis and are included in Commodity revenue on our Consolidated Statements of Operations.

Unrealized Mark-to-Market Gain (Loss) — The changes in the unrealized mark-to-market value of power-based commodity derivative instruments are reflected on a net basis as a separate component of operating revenues.

Leases — We have contracts, such as certain tolling agreements, which we account for as operating leases under U.S. GAAP. Generally, we levelize certain components of these contract revenues on a straight-line basis over the term of the contract. The total contractual future minimum lease rentals for our contracts accounted for as operating leases at December 31, 2013, are as follows (in millions):

2014	$	632
2015		641
2016		582
2017		546
2018		517
Thereafter		2,577
Total	$	5,495

Accounting for Derivative Instruments

We enter into a variety of derivative instruments including both exchange traded and OTC power and natural gas forwards, options as well as instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) and interest rate swaps. We recognize all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for and are designated under the normal purchase normal sale exemption. Accounting for derivatives at fair value requires us to make estimates about future prices during periods for which price quotes are not available from sources external to us, in which case we rely on internally developed price estimates. See Note 8 for further discussion on our accounting for derivatives.

Fuel and Purchased Energy Expense

Fuel and purchased energy expense is comprised of the cost of natural gas and fuel oil purchased from third parties for the purposes of consumption in our power plants as fuel, and the cost of power and natural gas purchased from third parties for our marketing, hedging and optimization activities and realized settlements and unrealized mark-to-market gains and losses resulting from general market price movements against certain derivative natural gas contracts including financial natural gas transactions economically hedging anticipated future power sales that 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.

Realized and Unrealized Expenses from Commodity Derivative Instruments

Realized Settlements of Commodity Derivative Instruments — The realized value of natural gas purchase and sales commodity contracts that are net settled are reflected on a net basis and included in Commodity expense on our Consolidated Statements of Operations. Power purchase commodity contracts that result in the physical delivery of power, and that also supplement our power generation, are reflected on a gross basis and are included in Commodity expense on our Consolidated Statements of Operations.

Unrealized Mark-to-Market (Gain) Loss — The changes in the unrealized mark-to-market value of natural gas-based commodity derivative instruments are reflected on a net basis as a separate component of fuel and purchased energy expense.

Plant Operating Expense

Plant operating expense primarily includes employee expenses, utilities, chemicals, repairs and maintenance, insurance and property taxes. We recognize these expenses when the service is performed or in the period in which the expense relates.

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying values of existing assets and liabilities and their respective tax basis and tax credit and NOL carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities due to a change in tax rates is recognized in income in the period that includes the enactment date.

We recognize the financial statement effects of a tax position when it is more-likely-than-not, based on the technical merits, that the position will be sustained upon examination. A tax position that meets the more-likely-than-not recognition threshold is measured as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement with a taxing authority. We reverse a previously recognized tax position in the first period in which it is no longer more-likely-than-not that the tax position would be sustained upon examination. See Note 10 for a further discussion on our income taxes.

Earnings (Loss) per Share

Basic earnings (loss) per share is calculated using the weighted average shares outstanding during the period and includes restricted stock units for which no future service is required as a condition to the delivery of the underlying common stock. Diluted earnings (loss) per share is calculated by adjusting the weighted average shares outstanding by the dilutive effect of share-based awards using the treasury stock method. See Note 11 for a further discussion of our earnings (loss) per share.

Stock-Based Compensation

We use the Black-Scholes option-pricing model or the Monte Carlo simulation model to estimate the fair value of our employee stock options on the grant date. The Black-Scholes option-pricing model and the Monte Carlo simulation model take into account certain variables, which are further explained in Note 12.

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 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 8 for disclosures regarding our assets and liabilities that are presented gross on our Consolidated 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 8 for disclosures on the affect of significant reclassifications out of AOCI on the respective line items on our Consolidated Statements of Operations.

Income Taxes — In July 2013, the FASB issued Accounting Standards Update 2013-11, "Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists". The provisions of the rule require an unrecognized tax benefit to be presented as a reduction to a deferred tax asset in the financial statements for an NOL carryforward, a similar tax loss, or a tax credit carryforward except in circumstances when the carryforward or tax loss is not available at the reporting date under the tax laws of the applicable jurisdiction to settle any additional income taxes or the tax law does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purposes. When those circumstances exist, the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets. The new financial statement presentation provisions relating to this update are prospective and effective for interim and annual periods beginning after December 15, 2013, with early adoption permitted. We are currently assessing the future impact of this update, but we do not anticipate a material impact on our financial condition, results of operations or cash flows.

3. Acquisitions and Divestitures

Acquisition of Guadalupe Energy Center

On December 2, 2013, we announced that we have entered into an agreement, through our indirect, wholly-owned subsidiary Calpine Guadalupe GP, LLC, to purchase a power plant with a nameplate capacity of 1,050 MW owned by MinnTex Power Holdings, LLC, for approximately $625 million . The natural gas-fired, combined-cycle power plant will increase capacity in our Texas segment and is located in Guadalupe County, Texas, which is located northeast of San Antonio, Texas. The 110 acre site includes two 525 MW generation blocks, each consisting of two GE 7FA combustion turbines, two heat recovery steam generators and one GE steam turbine. The purchase price does not include $15 million in consideration for the rights we also acquired to an advanced development opportunity for an approximately 400 MW quick-start, natural gas-fired peaker, if market conditions warrant. We expect the transaction to close in the first quarter of 2014, subject to regulatory approvals, and will fund the acquisition with cash on hand or with cash on hand and financing.

Acquisition of Bosque Energy Center

On November 7, 2012, we, through our indirect, wholly-owned subsidiary Calpine Bosque Energy Center, LLC, completed the purchase of a power plant with a nameplate capacity of 800 MW owned by Bosque Power Co., LLC, for approximately $432 million. The modern, natural gas-fired, combined-cycle power plant increased capacity in our Texas segment and is located in Central Texas near the unincorporated community of Laguna Park in Bosque County. The site includes a 250 MW generation block with one natural-gas turbine, one heat recovery steam generator and one steam turbine that achieved COD in June 2001 and a 550 MW generation block with two natural-gas turbines that went online in June 2000 as well as two heat recovery steam generators and one steam turbine that achieved COD in June 2011. We funded the $432 million purchase price with cash on hand. The purchase price was primarily allocated to property, plant and equipment. We did not record any material adjustments to the preliminary purchase price allocation during 2013, which is now final, nor any goodwill as a result of this acquisition.

Sale of Riverside Energy Center

Our 603 MW Riverside Energy Center had a PPA that provided WP&L an option to purchase the power plant and plant-related assets upon written notice of exercise prior to May 31, 2012. On May 18, 2012, WP&L exercised their option to purchase Riverside Energy Center, LLC, one of our VIEs which owned Riverside Energy Center. The sale closed on December 31, 2012 for approximately $402 million, and we recorded a pre-tax gain of approximately $7 million, which is included in (gain) on sale of assets, net on our Consolidated Statements of Operations. We used the sale proceeds for our capital allocation activities and for general corporate purposes. The sale of Riverside Energy Center did not meet the criteria for treatment as discontinued operations.

Sale of Broad River

On December 27, 2012, we, through our indirect, wholly-owned subsidiary Calpine Power Company, completed the sale of 100% of our ownership interest in each of the Broad River Entities for approximately $423 million. This transaction resulted in the disposition of our Broad River power plant, an 847 MW natural gas-fired, peaking power plant located in Gaffney, South Carolina, and includes a five-year consulting agreement with the buyer. We recorded a pre-tax gain of approximately $215 million in December 2012, which is included in (gain) on sale of assets, net on our Consolidated Statements of Operations. We used the sale proceeds for our capital allocation activities and for general corporate purposes. The sale of the Broad River Entities did not meet the criteria for treatment as discontinued operations.

4. Property, Plant and Equipment, Net

As of December 31, 2013 and 2012, the components of property, plant and equipment are stated at cost less accumulated depreciation as follows (in millions):

	2013	2012	Depreciable Lives
Buildings, machinery and equipment[1]	$ 15,838	$ 14,774	3 – 47 Years
Geothermal properties	1,265	1,243	13 – 59 Years
Other	164	142	3 – 47 Years
	17,267	16,159	
Less: Accumulated depreciation	4,897	4,390	
	12,370	11,769	
Land	103	98	
Construction in progress[1]	522	1,138	
Property, plant and equipment, net	$ 12,995	$ 13,005	

(1) The change from December 31, 2012 to December 31, 2013 is primarily attributed to our Russell City and Los Esteros power plants commencing commercial operations during 2013.

We have various debt instruments that are collateralized by our property, plant and equipment. See Note 6 for a discussion of such instruments.

Buildings, Machinery and Equipment

This component primarily includes power plants and related equipment. Included in buildings, machinery and equipment are assets under capital leases. See Note 6 for further information regarding these assets under capital leases.

Geothermal Properties

This component primarily includes power plants and related equipment associated with our Geysers Assets.

Other

This component primarily includes software and emission reduction credits that are power plant specific and not available to be sold.

Capitalized Interest

The total amount of interest capitalized was $38 million, $38 million and $24 million for the years ended December 31, 2013, 2012 and 2011, respectively.

5. Variable Interest Entities and Unconsolidated Investments

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 year ended December 31, 2013. We have the following types of VIEs consolidated in our financial statements:

Subsidiaries with Project Debt — All of our subsidiaries with project debt not guaranteed by Calpine have PPAs that provide financial support and are thus considered VIEs. We retain ownership and absorb the full risk of loss and potential for reward once the project debt is paid in full. Actions by the lender to assume control of collateral can occur only under limited circumstances such as upon the occurrence of an event of default, which we have determined to be unlikely. See Note 6 for further information regarding our project debt and Note 2 for information regarding our restricted cash balances.

Subsidiaries with PPAs — Certain of our majority owned subsidiaries have PPAs that limit the risk and reward of our ownership and thus constitute a VIE.

VIE with a Purchase Option — OMEC has an agreement that provides a third party a fixed price option to purchase power plant assets exercisable in the year 2019. This purchase option limits the risk and reward of our ownership and, thus, constitutes a VIE.

Consolidation of VIEs

We consolidate our VIEs where we determine that we have both the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or receive benefits from the VIE. We have determined that we hold the obligation to absorb losses and receive benefits in all of our VIEs where we hold the majority equity interest. Therefore, our determination of whether to consolidate is based upon which variable interest holder has the power to direct the most significant activities of the VIE (the primary beneficiary). Our analysis includes consideration of the following primary activities which we believe to have a significant impact on a power plant's financial performance: operations and maintenance, plant dispatch, and fuel strategy as well as our ability to control or influence contracting and overall plant strategy. Our approach to determining which entity holds the powers and rights is based on powers held as of the balance sheet date. Contractual terms that may change the powers held in future periods, such as a purchase or sale option, are not considered in our analysis. Based on our analysis, we believe that we hold the power and rights to direct the most significant activities of all our majority-owned VIEs.

Under our consolidation policy and under U.S. GAAP we also:

- perform an ongoing reassessment each reporting period of whether we are the primary beneficiary of our VIEs; and
- evaluate if an entity is a VIE and whether we are the primary beneficiary whenever any changes in facts and circumstances occur such that the holders of the equity investment at risk, as a group, lose the power from voting rights or similar rights of those investments to direct the activities of a VIE that most significantly impact the VIE's economic performance or when there are other changes in the powers held by individual variable interest holders.

Noncontrolling Interest — We own a 75% interest in Russell City Energy Company, LLC, one of our VIEs, which is also 25% owned by a third party. We fully consolidate this entity in our Consolidated Financial Statements and account for the third party ownership interest as a noncontrolling interest.

VIE Disclosures

Our consolidated VIEs include natural gas-fired power plants with an aggregate capacity of 9,027 MW and 8,255 MW, at December 31, 2013 and 2012, respectively. 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. Other than amounts contractually required, we provided support to these VIEs in the form of cash and other contributions of nil, $20 million and $87 million for the years ended December 31, 2013, 2012 and 2011, respectively.

U.S. GAAP requires separate disclosure on the face of our Consolidated 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. 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. 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.

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 Balance Sheets. At December 31, 2013 and 2012, our equity method investments included on our Consolidated Balance Sheets were comprised of the following (in millions):

	Ownership Interest as of December 31, 2013	2013	2012
Greenfield LP	50%	$ 76	$ 69
Whitby	50%	17	12
Total investments in power plants		$ 93	$ 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 unconsolidated investments is not reflected on our Consolidated Balance Sheets. At December 31, 2013 and 2012, equity method investee debt was approximately $395 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 $198 million and $224 million at December 31, 2013 and 2012, respectively.

Our equity interest in the net income from Greenfield LP and Whitby for the years ended December 31, 2013, 2012 and 2011, 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 and distributions for the years indicated (in millions):

	(Income) from Unconsolidated Investments in Power Plants			Distributions		
	2013	2012	2011	2013	2012	2011
Greenfield LP	$ (16)	$ (17)	$ (12)	$ 18	$ 22	$ 2
Whitby	(14)	(11)	(9)	9	7	4
Total	$ (30)	$ (28)	$ (21)	$ 27	$ 29	$ 6

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) 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.

Significant Unconsolidated Subsidiaries — Greenfield LP and Whitby met the criteria of significant unconsolidated subsidiaries for the years ended December 31, 2013 and 2012, based upon the relationship of our equity income from our investment in these subsidiaries, when combined, to our consolidated net income before taxes. Aggregated summarized financial data for our unconsolidated subsidiaries is set forth below (in millions):

Condensed Combined Balance Sheets
of Our Unconsolidated Subsidiaries
December 31, 2013 and 2012

	2013	2012
Assets:		
Cash and cash equivalents	$ 57	$ 64
Current assets	25	30
Property, plant and equipment, net	588	648
Other assets	2	4
Total assets	$ 672	$ 746
Liabilities:		
Current maturities of long-term debt	$ 23	$ 25
Current liabilities	44	36
Long-term debt	372	423
Long-term derivative liabilities	35	84
Total liabilities	474	568
Member's interest	198	178
Total liabilities and member's interest	$ 672	$ 746

Condensed Combined Statements of Operations
of Our Unconsolidated Subsidiaries
For the Years Ended December 31, 2013, 2012 and 2011

	2013	2012	2011
Revenues	$ 207	$ 247	$ 277
Operating expenses	128	171	208
Income from operations	79	76	69
Interest expense, net of interest income	24	27	30
Other (income) expense, net	(3)	(2)	2
Net income	$ 58	$ 51	$ 37

6. Debt

Our debt at December 31, 2013 and 2012, was as follows (in millions):

	2013	2012
First Lien Notes	$ 4,989	$ 5,303
First Lien Term Loans	2,828	2,463
Project financing, notes payable and other	1,901	1,789
CCFC Term Loans	1,191	—
CCFC Notes	—	978
Capital lease obligations	203	217
Subtotal	11,112	10,750
Less: Current maturities	204	115
Total long-term debt	$ 10,908	$ 10,635

Our debt agreements contain covenants which could permit lenders to accelerate the repayment of our debt by providing notice, the lapse of time, or both, if certain events of default remain uncured after any applicable grace period. We were in compliance with all of the covenants in our debt agreements at December 31, 2013.

Annual Debt Maturities

Contractual annual principal repayments or maturities of debt instruments as of December 31, 2013, are as follows (in millions):

2014	$ 205
2015	183
2016	194
2017	550
2018	1,717
Thereafter	8,291
Subtotal	11,140
Less: Discount	28
Total debt	$ 11,112

First Lien Notes

Our First Lien Notes are summarized in the table below (in millions, except for interest rates):

	Outstanding at December 31,		Weighted Average Effective Interest Rates[3]	
	2013	2012	2013	2012
2017 First Lien Notes[1]	$ —	$ 1,080	—%	7.5%
2019 First Lien Notes[2]	320	360	8.2	8.2
2020 First Lien Notes[2]	875	983	8.2	8.1
2021 First Lien Notes[2]	1,600	1,800	7.7	7.7
2022 First Lien Notes[1]	744	—	6.2	—
2023 First Lien Notes[2]	960	1,080	8.0	8.0
2024 First Lien Notes[2]	490	—	5.9	—
Total First Lien Notes	$ 4,989	$ 5,303		

(1) On October 17, 2013, we launched a tender offer to repay our 2017 First Lien Notes with the proceeds from our 2020 First Lien Term Loan and 2022 First Lien Notes which are described in further detail below. On October 31, 2013, following the early tender and consent date of the tender offer, we purchased approximately $742 million in aggregate principal amount of our 2017 First Lien Notes and issued a redemption notice to the remaining holders of our 2017 First Lien Notes that did not tender their notes in the tender offer. The tender offer expired on November 29, 2013 and we purchased the remaining $338 million in aggregate principal amount of our 2017 First Lien Notes tendered prior to the expiration of the tender offer, and redeemed any remaining 2017 First Lien Notes on December 2, 2013.

(2) On October 31, 2013, we issued $490 million in aggregate principal amount of our 2024 First Lien Notes and used the proceeds to redeem 10% of the original aggregate principal amount of our 2019 First Lien Notes, 2020 First Lien Notes, 2021 First Lien Notes and 2023 First Lien Notes at a redemption price of 103% of the principal amount redeemed, plus accrued and unpaid interest.

(3) Our weighted average interest rate calculation includes the amortization of deferred financing costs and debt discount.

Our First Lien Notes are secured equally and ratably with indebtedness incurred under our First Lien Term Loans and Corporate Revolving Facility, subject to certain exceptions and permitted liens, on substantially all of our and certain of the guarantors' existing and future assets. Additionally, our First Lien Notes rank equally in right of payment with all of our and the guarantors' other existing and future senior indebtedness, and will be effectively subordinated in right of payment to all existing and future liabilities of our subsidiaries that do not guarantee our First Lien Notes.

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

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

2022 First Lien Notes

On October 31, 2013, we issued $750 million in aggregate principal amount of 6.0% senior secured notes due 2022 in a private placement. The 2022 First Lien Notes bear interest at 6.0% payable semi-annually on January 15 and July 15 of each year, beginning on July 15, 2014. We used the net proceeds received, together with the proceeds from the 2020 First Lien Term Loan, to repay the 2017 First Lien Notes during the fourth quarter of 2013. The 2022 First Lien Notes mature on January 15, 2022.

The 2022 First Lien Notes were offered to investors at an issue price equal to 99.193% of face value and contain substantially similar covenants, qualifications, exceptions and limitations as the First Lien Notes. We recorded approximately $12 million in deferred financing costs related to our 2022 First Lien Notes and approximately $51 million of debt extinguishment costs associated with the redemption premium and write-off of unamortized deferred financing costs related to the repayment of our 2017 First Lien Notes during the fourth quarter of 2013.

2024 First Lien Notes

On October 31, 2013, we issued $490 million in aggregate principal amount of 5.875% senior secured notes due 2024 in a private placement. The 2024 First Lien Notes bear interest at 5.875% payable semi-annually on January 15 and July 15 of each year, beginning on January 15, 2014. We used the net proceeds received from this issuance to redeem 10% of the original aggregate principal amount of our 2019 First Lien Notes, 2020 First Lien Notes, 2021 First Lien Notes and 2023 First Lien Notes at a redemption price of 103% of the principal amount redeemed, plus accrued and unpaid interest. The 2024 First Lien Notes mature on January 15, 2024.

The 2024 First Lien Notes contain substantially similar covenants, qualifications, exceptions and limitations as the First Lien Notes. We recorded approximately $8 million in deferred financing costs related to our 2024 First Lien Notes and approximately $20 million of debt extinguishment costs associated with the redemption premium and write-off of unamortized deferred financing costs and discount during the fourth quarter of 2013.

First Lien Term Loans

Our First Lien Term Loans are summarized in the table below (in millions, except for interest rates):

	Outstanding at December 31,		Weighted Average Effective Interest Rates(1)	
	2013	2012	2013	2012
2018 First Lien Term Loans	$ 1,614	$ 1,630	4.3%	4.7%
2019 First Lien Term Loan	824	833	4.5	4.7
2020 First Lien Term Loan	390	—	4.3	—
Total First Lien Term Loans	$ 2,828	$ 2,463		

(1) Our weighted average interest rate calculation includes the amortization of deferred financing costs and debt discount.

Our First Lien Term Loans provide for senior secured term loan facilities and bear interest, at our option, at either (i) the base rate, equal to the higher of the Federal Funds effective rate plus 0.5% per annum or the Prime Rate (as such terms are defined in the First Lien Term Loans credit agreements), plus an applicable margin of 2.0%, or (ii) LIBOR plus 3.0% per annum subject to a LIBOR floor of 1.0%. An aggregate amount equal to 0.25% of the aggregate principal amount of the First Lien Term Loans will be payable at the end of each quarter with the remaining balance payable on the maturity date. The First Lien Term Loans are subject to certain qualifications and exceptions, similar to our First Lien Notes. The 2018 First Lien Term Loans have a maturity date of April 1, 2018. The 2019 First Lien Term Loan carries substantially the same terms as the 2018 First Lien Term Loans and matures on October 9, 2019.

2020 First Lien Term Loan

On October 23, 2013, we entered into our $390 million 2020 First Lien Term Loan. We used the net proceeds received, together with the proceeds from the 2022 First Lien Notes to repay the 2017 First Lien Notes during the fourth quarter of 2013. The 2020 First Lien Term Loan matures on October 31, 2020 and carries substantially the same terms as the First Lien Term Loans. The 2020 First Lien Term Loan also contains substantially similar covenants, qualifications, exceptions and limitations as the First Lien Term Loans and First Lien Notes. We recorded approximately $6 million in deferred financing costs during the fourth quarter of 2013 related to the issuance of the 2020 First Lien Term Loan.

Project Financing, Notes Payable and Other

The components of our project financing, notes payable and other are (in millions, except for interest rates):

	Outstanding at December 31,		Weighted Average Effective Interest Rates(1)	
	2013	2012	2013	2012
Russell City Project Debt due 2023	$ 593	$ 507	4.9%	3.6%
Steamboat due 2017	418	428	6.8	6.8
OMEC due 2019	335	345	6.9	6.8
Los Esteros Project Debt due 2023	305	209	3.4	3.5
Pasadena(2)	135	160	8.9	8.9
Bethpage Energy Center 3 due 2020-2025(3)	88	93	7.0	7.0
Gilroy note payable due 2014	15	33	11.2	10.8
Other	12	14	—	—
Total	$ 1,901	$ 1,789		

(1) Our weighted average interest rate calculation includes the amortization of deferred financing costs and debt discount or premium.

(2) Represents a sale-leaseback transaction that is accounted for as financing transaction under U.S. GAAP.

(3) Represents a weighted average of first and second lien loans for the weighted average effective interest rates.

Our project financings are collateralized solely by the capital stock or partnership interests, physical assets, contracts and/or cash flows attributable to the entities that own the power plants. The lenders' recourse under these project financings is limited to such collateral.

CCFC Term Loans and Repayment of CCFC Notes

Our CCFC Term Loans and CCFC Notes are summarized in the table below (in millions, except for interest rates):

	Outstanding at December 31,		Weighted Average Effective Interest Rates(1)	
	2013	2012	2013	2012
CCFC Term Loans	$ 1,191	$ —	3.3%	—%
CCFC Notes	—	978	—	8.9
Total CCFC Term Loans and CCFC Notes	$ 1,191	$ 978		

(1) Our weighted average interest rate calculation includes the amortization of deferred financing costs and debt discount.

CCFC Term Loans

On May 3, 2013, CCFC entered into a credit agreement providing for a first lien senior secured term loan facility comprised of (i) a $900 million 7-year term loan and (ii) a $300 million 8.5-year term loan.

CCFC utilized the proceeds received from the CCFC Term Loans to redeem the entire $1.0 billion in principal amount of CCFC Notes at a redemption price equal to 104% (plus accrued and unpaid interest), to pay related transaction expenses and for corporate purposes, as described in the credit agreement. The CCFC Notes were redeemed on June 3, 2013, at which date the CCFC Term Loans were fully drawn.

The CCFC Term Loans bear interest, at CCFC's option, at either (i) the Base Rate, equal to the higher of the Federal Funds Effective Rate plus 0.50% per annum or the Prime Rate (as such terms are defined in the Credit Agreement), plus an applicable margin of (a) 1.25% per annum with respect to the 7-year term loan and (b) 1.50% per annum with respect to the 8.5-year term loan, or (ii) LIBOR plus (a) 2.25% per annum with respect to the 7-year term loan and (b) 2.50% per annum with respect to the 8.5-year term loan (in each case subject to a LIBOR floor of 0.75%). The term loans were offered to investors at an issue price equal to 99.75% of face value.

An amount equal to 0.25% of the aggregate principal amount of the CCFC Term Loans are payable at the end of each quarter commencing in September 2013, with the remaining balance payable on the relevant maturity date (May 3, 2020 with respect to the 7-year term loan and January 31, 2022 with respect to the 8.5-year term loan). CCFC may elect from time to time to convert all or a portion of the CCFC Term Loans from LIBOR loans to Base Rate loans or vice versa. In addition, CCFC may at any time, and from time to time, prepay the term loans, in whole or in part, without premium or penalty, upon irrevocable notice to the administrative agent.

The CCFC Term Loans are secured by certain real and personal property of CCFC consisting primarily of six natural gas-fired power plants. The CCFC Term Loans are not guaranteed by Calpine Corporation and are without recourse to Calpine Corporation or any of our non-CCFC subsidiaries or assets; however, CCFC generates the majority of its cash flows from an intercompany tolling agreement with Calpine Energy Services, L.P. and has various service agreements in place with other subsidiaries of Calpine Corporation.

In connection with the redemption of the CCFC Notes, we recorded $68 million in debt extinguishment costs associated with prepayment penalties and the write-off of unamortized debt discount and deferred financing costs during the year ended December 31, 2013. We also recorded $15 million in new deferred financing costs on our Consolidated Balance Sheet during 2013 associated with the issuance of the CCFC Term Loans.

Capital Lease Obligations

The following is a schedule by year of future minimum lease payments under capital leases and a failed sale-leaseback transaction related to our Pasadena Power Plant together with the present value of the net minimum lease payments as of December 31, 2013 (in millions):

	Sale-Leaseback Transactions(1)	Capital Lease	Total
2014	$ 25	$ 51	$ 76
2015	25	38	63
2016	25	40	65
2017	17	38	55
2018	21	37	58
Thereafter	106	125	231
Total minimum lease payments	219	329	548
Less: Amount representing interest	84	126	210
Present value of net minimum lease payments	$ 135	$ 203	$ 338

(1) Amounts are accounted for as financing transactions under U.S. GAAP and are included in our project financing, notes payable and other amounts above.

The primary types of property leased by us are power plants and related equipment. The leases generally provide for the lessee to pay taxes, maintenance, insurance, and certain other operating costs of the leased property. The remaining lease terms range up to 35 years (including lease renewal options). Some of the lease agreements contain customary restrictions on dividends up to Calpine Corporation, additional debt and further encumbrances similar to those typically found in project financing agreements. At December 31, 2013 and 2012, the asset balances for the leased assets totaled approximately $862 million and $880 million with accumulated amortization of $343 million and $312 million, respectively. Amortization of assets under capital leases is recorded in depreciation and amortization expense on our Consolidated Statements of Operations. See Note 15 for discussion of capital leases guaranteed by Calpine Corporation.

Corporate Revolving Facility and Other Letters of Credit Facilities

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

	2013	2012
Corporate Revolving Facility	$ 242	$ 243
CDHI	218	253
Various project financing facilities	170	130
Total	$ 630	$ 626

On June 27, 2013, we executed Amendment No.1 to the Corporate Revolving Facility. Certain key terms of the amendment are listed below:

- the applicable margin has been reduced from 3.25% to 2.25% for LIBOR rate borrowings and from 2.25% to 1.25% for base rate borrowings;
- the fee on the undrawn commitment has been reduced from 0.75% to 0.50%; and
- the maturity date of the Corporate Revolving Facility has been extended to June 27, 2018.

The Corporate Revolving Facility represents our primary revolving facility. Borrowings under the Corporate Revolving Facility bear interest, at our option, at either a base rate or LIBOR rate. Base rate borrowings shall be at the base rate, plus an applicable margin ranging from 1.00% to 1.25% as provided in the Corporate Revolving Facility credit agreement. Base rate is defined as the higher of (i) the Federal Funds Effective Rate, as published by the Federal Reserve Bank of New York, plus 0.50% and (ii) the rate the administrative agent announces from time to time as its prime per annum rate. LIBOR rate borrowings shall be at the British Bankers' Association Interest Settlement Rates for the interest period as selected by us as a one, two, three, six or, if agreed by all relevant lenders, nine or twelve month interest period, plus an applicable margin ranging from 2.00% to 2.25%.

Interest payments are due on the last business day of each calendar quarter for base rate loans and the earlier of (i) the last day of the interest period selected or (ii) each day that is three months (or a whole multiple thereof) after the first day for the interest period selected for LIBOR rate loans. Letter of credit fees for issuances of letters of credit include fronting fees equal to that percentage per annum as may be separately agreed upon between us and the issuing lenders and a participation fee for the lenders equal to the applicable interest margin for LIBOR rate borrowings. Drawings under letters of credit shall be repaid within two business days or be converted into borrowings as provided in the Corporate Revolving Facility credit agreement. We incur an unused commitment fee ranging from 0.25% to 0.50% on the unused amount of commitments under the Corporate Revolving Facility.

The Corporate Revolving Facility does not contain any requirements for mandatory prepayments, except in the case of certain designated asset sales in excess of $3.0 billion in the aggregate. However, we may voluntarily repay, in whole or in part, the Corporate Revolving Facility, together with any accrued but unpaid interest, with prior notice and without premium or penalty. Amounts repaid may be reborrowed, and we may also voluntarily reduce the commitments under the Corporate Revolving Facility without premium or penalty. The Corporate Revolving Facility matures on June 27, 2018.

The Corporate Revolving Facility is guaranteed and secured by each of our current domestic subsidiaries that was a guarantor under the First Lien Credit Facility and will also be additionally guaranteed by our future domestic subsidiaries that are required to provide such a guarantee in accordance with the terms of the Corporate Revolving Facility. The Corporate Revolving Facility ranks equally in right of payment with all of our and the guarantors' other existing and future senior indebtedness and will be effectively subordinated in right of payment to all existing and future liabilities of our subsidiaries that do not guarantee the Corporate Revolving Facility. The Corporate Revolving Facility also requires compliance with financial covenants that include a minimum cash interest coverage ratio and a maximum net leverage ratio.

CDHI

We have $300 million letter of credit facility related to CDHI which matures on January 2, 2016. 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 December 31, 2013, we had no outstanding letters of credit issued in excess of $225 million under our CDHI letter of credit facility that were collateralized by cash.

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 December 31, 2013 and 2012 (in millions):

	2013		2012	
	Fair Value	Carrying Value	Fair Value	Carrying Value
First Lien Notes	$ 5,317	$ 4,989	$ 5,863	$ 5,303
First Lien Term Loans	2,845	2,828	2,489	2,463
Project financing, notes payable and other[1]	1,772	1,766	1,599	1,629
CCFC Term Loans	1,179	1,191	—	—
CCFC Notes	—	—	1,075	978
Total	$ 11,113	$ 10,774	$ 11,026	$ 10,373

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

On January 1, 2012, we adopted Accounting Standards Update 2011-04 "Fair Value Measurement" which requires the categorization by level of the fair value hierarchy for items not measured at fair value on our Consolidated Balance Sheets but for which fair value is required to be disclosed. We measure the fair value of our First Lien Notes, First Lien Term Loans, CCFC 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.

7. 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 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 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. 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 December 31, 2013 and 2012, by level within the fair value hierarchy:

	Assets and Liabilities with Recurring Fair Value Measures as of December 31, 2013			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Cash equivalents[1]	$ 1,134	$ —	$ —	$ 1,134
Margin deposits	261	—	—	261
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	434	—	—	434
Commodity forward contracts[2]	—	75	32	107
Interest rate swaps	—	9	—	9
Total assets	$ 1,829	$ 84	$ 32	$ 1,945
Liabilities:				
Margin deposits posted with us by our counterparties	$ 5	$ —	$ —	$ 5
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	495	—	—	495
Commodity forward contracts[2]	—	52	18	70
Interest rate swaps	—	129	—	129
Total liabilities	$ 500	$ 181	$ 18	$ 699

	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

(1) As of December 31, 2013 and 2012, we had cash equivalents of $889 million and $1,274 million included in cash and cash equivalents and $245 million and $228 million included in restricted cash, respectively.

(2) Includes OTC swaps and options.

At December 31, 2013, the derivative instruments classified as level 3 primarily included two commodity contracts which are classified as level 3 because the contract terms relate to a delivery location for which observable market rate information is not available, as well as financial power congestion products which settle on the price differential between two power delivery locations, at least one of which is also deemed unobservable. 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 December 31, 2013 and 2012:

	Quantitative Information about Level 3 Fair Value Measurements				
	December 31, 2013				
	Fair Value, Net Asset (Liability) (in millions)		Valuation Technique	Significant Unobservable Input	Range
Physical Power	$	7	Discounted cash flow	Market price (per MWh)	$28.92 — $53.15/MWh
Power Congestion Products	$	7	Discounted cash flow	Market price (per MWh)	$(8.79) — $11.53/MWh

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

The following table sets forth a reconciliation of changes in the fair value of our net derivative assets (liabilities) classified as level 3 in the fair value hierarchy for the years ended December 31, 2013, 2012 and 2011 (in millions):

	2013	2012	2011
Balance, beginning of period	$ 16	$ 17	$ 30
Realized and unrealized gains:			
Included in net income (loss):			
Included in operating revenues[(1)]	5	8	5
Included in fuel and purchased energy expense[(2)]	—	—	—
Included in OCI	—	—	2
Purchases, issuances and settlements:			
Purchases	6	3	—
Issuances	(2)	(1)	—
Settlements	(11)	(11)	(18)
Transfers in and/or out of level 3[(3)]:			
Transfers into level 3[(4)]	—	—	(2)
Transfers out of level 3[(5)]	—	—	—
Balance, end of period	$ 14	$ 16	$ 17
Change in unrealized gains relating to instruments still held at end of period	$ 5	$ 8	$ 5

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(1) For power contracts and other power-related products, included on our Consolidated Statements of Operations.

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

(3) We transfer amounts among levels of the fair value hierarchy as of the end of each period. There were no transfers into or out of level 1 during the years ended December 31, 2013, 2012 and 2011.

(4) There were no transfers out of level 2 into level 3 for the years ended December 31, 2013 and 2012. We had $2 million in losses transferred out of level 2 into level 3 for the year ended December 31, 2011 due to changes in market liquidity in various power and natural gas markets.

(5) We had no significant transfers out of level 3 for the years ended December 31, 2013, 2012 and 2011.

8. Derivative Instruments

Types of Derivative Instruments and Volumetric Information

Commodity Instruments — We are exposed to changes in prices for the purchase and sale of power, natural gas, environmental products 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 December 31, 2013, the maximum length of time over which we were hedging using interest rate derivative instruments designated as cash flow hedges was 10 years.

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

	Notional Amounts	
Derivative Instruments	**2013**	**2012**
Power (MWh)	(29)	(16)
Natural gas (MMBtu)	448	66
Interest rate swaps	$ 1,527	$ 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 December 31, 2013, was $8 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 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 Statements of Operations and could create 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 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 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, interest rate and environmental product 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 Statements of Operations in unrealized mark-to-market gain/loss as a component of operating revenues (for power and environmental product 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 Statement of Operations for the year ended December 31, 2012, and approximately $142 million reflected the realization of losses recorded in prior periods.

Derivatives Included on Our Consolidated Balance Sheet

During the first quarter of 2012, we de-designated our remaining commodity derivative cash flow hedges; therefore, as of December 31, 2013 and 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 Balance Sheets by location and hedge type at December 31, 2013 and 2012 (in millions):

	December 31, 2013		
	Commodity Instruments	Interest Rate Swaps	Total Derivative Instruments
Balance Sheet Presentation			
Current derivative assets	$ 445	$ —	$ 445
Long-term derivative assets	96	9	105
Total derivative assets	$ 541	$ 9	$ 550
Current derivative liabilities	$ 404	$ 47	$ 451
Long-term derivative liabilities	161	82	243
Total derivative liabilities	$ 565	$ 129	$ 694
Net derivative assets (liabilities)	$ (24)	$ (120)	$ (144)

	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 assets (liabilities)	$ (17)	$ (196)	$ (213)

	December 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	$ 9	$ 115	$ 4	$ 184
Total derivatives designated as cash flow hedging instruments	$ 9	$ 115	$ 4	$ 184
Derivatives not designated as hedging instruments:				
Commodity instruments	$ 541	$ 565	$ 433	$ 450
Interest rate swaps	—	14	—	16
Total derivatives not designated as hedging instruments	$ 541	$ 579	$ 433	$ 466
Total derivatives	$ 550	$ 694	$ 437	$ 650

We elected not to offset fair value amounts recognized as derivative instruments on our Consolidated 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 December 31, 2013 and 2012 (in millions):

	December 31, 2013			
	Gross Amounts Not Offset on the Consolidated Balance Sheets			
	Gross Amounts Presented on our Consolidated Balance Sheets	Derivative Asset (Liability) not Offset on the Consolidated Balance Sheets	Margin/Cash (Received) Posted (1)	Net Amount
Derivative assets:				
Commodity exchange traded futures and swaps contracts	$ 434	$ (420)	$ (14)	$ —
Commodity forward contracts	107	(60)	—	47
Interest rate swaps	9	—	—	9
Total derivative assets	$ 550	$ (480)	$ (14)	$ 56
Derivative (liabilities):				
Commodity exchange traded futures and swaps contracts	$ (495)	$ 420	$ 75	$ —
Commodity forward contracts	(70)	60	1	(9)
Interest rate swaps	(129)	—	—	(129)
Total derivative (liabilities)	$ (694)	$ 480	$ 76	$ (138)
Net derivative assets (liabilities)	$ (144)	$ —	$ 62	$ (82)

	December 31, 2012			
	Gross Amounts Not Offset on the Consolidated Balance Sheets			
	Gross Amounts Presented on our Consolidated Balance Sheets	Derivative Asset (Liability) not Offset on the Consolidated 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 posted by us with our counterparties related to our derivative activities that are subject to a master netting arrangement. See Note 9 for a further discussion of our collateral.

Derivatives Included on Our Consolidated Statements of Operations

Changes in the fair values of our derivative instruments (both assets and liabilities) are reflected either in cash for option premiums paid or collected, in OCI, net of tax, for the effective portion of derivative instruments which qualify for and we have elected cash flow hedge accounting treatment, or on our Consolidated Statements of Operations as a component of unrealized 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 Statements of Operations for the years ended December 31, 2013, 2012 and 2011 (in millions):

	2013	2012	2011
Realized gain (loss)[1]			
Commodity derivative instruments	$ 86	$ 387	$ 143
Interest rate swaps	—	(157)	(193)
Total realized gain (loss)	$ 86	$ 230	$ (50)
Unrealized gain (loss)[2]			
Commodity derivative instruments	$ (14)	$ (82)	$ (25)
Interest rate swaps	2	154	55
Total unrealized gain (loss)	$ (12)	$ 72	$ 30
Total mark-to-market activity, net	$ 74	$ 302	$ (20)

(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.

	2013	2012	2011
Realized and unrealized gain (loss)			
Derivatives contracts included in operating revenues	$ (119)	$ 187	$ (20)
Derivatives contracts included in fuel and purchased energy expense	191	118	138
Interest rate swaps included in interest expense	2	11	7
Loss on interest rate derivatives	—	(14)	(145)
Total mark-to-market activity, net	$ 74	$ 302	$ (20)

Derivatives Included in OCI and AOCI

The following table details the effect of our net derivative instruments that qualified for hedge accounting treatment and are included in OCI and AOCI for the years ended December 31, 2013, 2012 and 2011 (in millions):

	Gains (Loss) Recognized in OCI (Effective Portion)[3]			Gain (Loss) Reclassified from AOCI into Income (Effective Portion)[4]			
	2013	2012	2011	2013	2012	2011	Affected Line Item on the Consolidated Statements of Operations
Commodity derivative instruments[1]:							
Power derivative instruments	$ —	$ (97)	$ (99)	$ —	$ 118	$ 236	Commodity revenue
Natural gas derivative instruments	—	59	28	—	(66)	(73)	Commodity expense
Interest rate swaps[2]	86	(43)	(23)	(51) [5]	(32)	(47) [6]	Interest expense
Interest rate swaps	—	—	—	—	—	(91) [6]	Loss on interest rate derivatives
Total[3]	$ 86	$ (81)	$ (94)	$ (51)	$ 20	$ 25	

(1) There were no commodity derivative instruments designated as cash flow hedges during the year ended December 31, 2013. We recorded a gain on hedge ineffectiveness of $2 million and a loss of $2 million related to our commodity derivative instruments designated as cash flow hedges during the years ended December 31, 2012 and 2011, respectively.

(2) We did not record any gain (loss) on hedge ineffectiveness related to our interest rate swaps designated as cash flow hedges during the years ended December 31, 2013 and 2012. We recorded a loss of $1 million on hedge ineffectiveness related to our interest rate swaps designated as cash flow hedges for the year ended December 31, 2011.

(3) We recorded income tax expense of $3 million for the year ended December 31, 2013, and an income tax benefit of $11 million and $44 million for the years ended December 31, 2012 and 2011, respectively, in AOCI related to our cash flow hedging activities.

(4) Cumulative cash flow hedge losses attributable to Calpine, net of tax, remaining in AOCI were $148 million, $222 million and $158 million at December 31, 2013, 2012 and 2011, respectively. Cumulative cash flow hedge losses attributable to the noncontrolling interest, net of tax, remaining in AOCI were $11 million, $20 million and $14 million at December 31, 2013, 2012 and 2011, respectively.

(5) Includes a loss of $12 million that was reclassified from AOCI to interest expense for the year ended December 31, 2013 where the hedged transactions are no longer expected to occur.

(6) Includes a loss of $15 million and $91 million that was reclassified from AOCI to interest expense and loss on interest rate derivatives, respectively, for the year ended December 31, 2011 where the hedged transactions are no longer expected to occur.

We estimate that pre-tax net losses of $43 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.

9. Use of Collateral

We use margin deposits, prepayments and letters of credit as credit support with and from our counterparties for commodity procurement and risk management activities. In addition, we have granted additional first priority liens on the assets currently subject to first priority liens under 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 December 31, 2013 and 2012 (in millions):

	2013	2012
Margin deposits[(1)]	$ 261	$ 196
Natural gas and power prepayments	28	35
Total margin deposits and natural gas and power prepayments with our counterparties[(2)]	$ 289	$ 231
Letters of credit issued	$ 488	$ 484
First priority liens under power and natural gas agreements	31	14
First priority liens under interest rate swap agreements	132	206
Total letters of credit and first priority liens with our counterparties	$ 651	$ 704
Margin deposits posted with us by our counterparties[(1)(3)]	$ 5	$ 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	$ 7	$ 12

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(1) Balances are subject to master netting arrangements and presented on a gross basis on our Consolidated Balance Sheets. We do not offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement for financial statement presentation, 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 8 for further discussion of our derivative instruments subject to master netting arrangements.

(2) At December 31, 2013 and 2012, $272 million and $211 million, respectively, were included in margin deposits and other prepaid expense and $17 million and $20 million, respectively, were included in other assets on our Consolidated Balance Sheets.

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

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

10. Income Taxes

Income Tax Expense (Benefit)

The jurisdictional components of income (loss) from continuing operations before income tax expense (benefit), attributable to Calpine, for the years ended December 31, 2013, 2012 and 2011, are as follows (in millions):

	2013	2012	2011
U.S.	$ (13)	$ 194	$ (232)
International	29	24	20
Total	$ 16	$ 218	$ (212)

The components of income tax expense (benefit) from continuing operations for the years ended December 31, 2013, 2012 and 2011, consisted of the following (in millions):

	2013	2012	2011
Current:			
Federal	$ (2)	$ (12)	$ (16)
State	(9)	16	12
Foreign	(1)	14	3
Total current	(12)	18	(1)
Deferred:			
Federal	1	11	(33)
State	4	(5)	9
Foreign	9	(5)	3
Total deferred	14	1	(21)
Total income tax expense (benefit)	$ 2	$ 19	$ (22)

For the years ended December 31, 2013, 2012 and 2011, our income tax rates did not bear a customary relationship to statutory income tax rates, primarily as a result of the impact of our valuation allowance, state income taxes and changes in unrecognized tax benefits. A reconciliation of the federal statutory rate of 35% to our effective rate from continuing operations for the years ended December 31, 2013, 2012 and 2011, is as follows:

	2013	2012	2011
Federal statutory tax expense (benefit) rate	35.0%	35.0%	(35.0)%
State tax expense (benefit), net of federal benefit	(69.8)	3.2	6.5
Depletion in excess of basis	(14.7)	(0.2)	—
Federal refunds	—	(4.7)	—
Valuation allowances against future tax benefits	89.8	(30.3)	57.1
Valuation allowance related to reconsolidation of CCFC	—	—	(36.0)
Valuation allowance related to foreign taxes	(19.8)	(8.2)	—
Foreign taxes	(10.8)	3.7	(0.9)
Bankruptcy settlement	—	—	(15.7)
Intraperiod allocation	4.5	4.6	19.9
Change in unrecognized tax benefits	(30.1)	5.1	(6.6)
Disallowed compensation	11.7	0.4	0.3
Stock-based compensation	8.6	0.2	0.1
Lobbying contributions	3.3	0.3	0.4
Other differences	4.8	(0.4)	(0.5)
Effective income tax expense (benefit) rate	12.5%	8.7%	(10.4)%

Deferred Tax Assets and Liabilities

The components of deferred income taxes as of December 31, 2013 and 2012, are as follows (in millions):

	2013	2012
Deferred tax assets:		
NOL and credit carryforwards	$ 3,120	$ 3,073
Taxes related to risk management activities and derivatives	60	90
Reorganization items and impairments	262	315
Foreign capital losses	18	25
Other differences	104	60
Deferred tax assets before valuation allowance	3,564	3,563
Valuation allowance	(2,246)	(2,222)
Total deferred tax assets	1,318	1,341
Deferred tax liabilities: property, plant and equipment	(1,310)	(1,316)
Net deferred tax asset	8	25
Less: Current portion deferred tax asset (liability)	12	(3)
Less: Non-current deferred tax asset	7	28
Deferred income tax liability, non-current	$ (11)	$ —

Consolidation of CCFC and Calpine Tax Reporting Groups — For federal income tax reporting purposes, our historical tax reporting group was comprised primarily of two separate groups, CCFC and its subsidiaries, which we referred to as the CCFC group, and Calpine Corporation and its subsidiaries other than CCFC, which we referred to as the Calpine group. During the first quarter of 2011, we elected to consolidate our CCFC and Calpine groups for federal income tax reporting purposes and Calpine filed a consolidated federal income tax return for the year ended December 31, 2011 that included the CCFC group. As a result of the consolidation, the CCFC group deferred tax liabilities will be eligible to offset existing Calpine group NOLs that were reserved by a valuation allowance. Accordingly, we recorded a one-time federal deferred income tax benefit of approximately $76 million during the first quarter of 2011 to reduce our valuation allowance.

Intraperiod Tax Allocation — In accordance with U.S. GAAP, intraperiod tax allocation provisions require allocation of a tax expense (benefit) to continuing operations due to current OCI gains (losses) with a partial offsetting amount recognized in OCI. The following table details the effects of our intraperiod tax allocations for the years ended December 31, 2013, 2012 and 2011 (in millions).

	2013	2012	2011
Intraperiod tax allocation expense included in continuing operations	$ 1	$ 9	$ 42
Intraperiod tax allocation benefit included in OCI	$ (1)	$ (9)	$ (45)

NOL Carryforwards — Our NOL carryforwards consist primarily of federal NOL carryforwards of approximately $7.5 billion, which expire between 2023 and 2033, and NOL carryforwards in 33 states and the District of Columbia totaling approximately $4.1 billion, which expire between 2014 and 2033, substantially all of which are offset with a full valuation allowance. We also have approximately $900 million in foreign NOLs, which expire between 2026 and 2033, substantially all of which are offset with a full valuation allowance. Under federal income tax law, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of the IRC. If a subsequent ownership change were to occur as a result of future transactions in our stock, accompanied by a significant reduction in our market value immediately prior to the ownership change, our ability to utilize the NOL carryforwards may be significantly limited.

Deferred tax assets relating to tax benefits of employee stock-based compensation do not reflect stock options exercised and restricted stock that vested between 2011 and 2013. Some stock option exercises and restricted stock vestings result in tax deductions in excess of previously recorded deferred tax benefits based on the equity award value at the grant date. Although these additional tax benefits or “windfalls” are reflected in NOL carryforwards pursuant to accounting for stock-based compensation under U.S. GAAP, the additional tax benefit associated with the windfall is not recognized until the deduction reduces taxes payable, which will not occur for Calpine until a future period. Accordingly, since the tax benefit does not reduce our current taxes payable for the years ended December 31, 2013 and 2012 due to NOL carryforwards, these “windfall” tax benefits are not reflected in our NOLs in deferred tax assets at December 31, 2013 and 2012. The cumulative windfall balance included in federal and state NOL carryforwards, but not reflected in gross deferred tax assets as of December 31, 2013 and 2012 were $25 million and $9 million for federal, respectively, and $16 million and $7 million for state, respectively.

As a result of the settlement of certain bankruptcy claims and the final distribution to the holders of allowed unsecured claims in accordance with our Plan of Reorganization in 2011, we recognized approximately $66 million and $39 million for federal and state income tax purposes, respectively, in cancellation of debt income related to this distribution for federal income tax reporting in 2011.

Income Tax Audits — We remain subject to periodic audits and reviews by taxing authorities; however, we do not expect these audits 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”). We proposed a settlement of the adjusted reassessment with the CRA and it has accepted our proposal. The adjustment to our transfer pricing increased taxable income and was offset by existing NOLs to which a valuation allowance had been applied.

On January 28, 2014, we received a letter from the CRA which informed us that they do not agree with our transfer price on the second issue and will be proposing an increase to taxable income for tax years 2006 and 2007. We continue to believe that our transfer pricing positions and policies are appropriate, and we intend to vigorously defend our position and challenge the CRA’s adjustments, including but not limited to appeal and litigation. If we are unsuccessful in our challenge, any adjustment to Canadian taxable income would first be offset against the existing NOLs that are available. If our existing Canadian NOL’s are not sufficient to offset the resulting adjustment to taxable income, additional assessments, including penalties and interest, would not 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.

As of December 31, 2013, we have provided a valuation allowance of approximately $2.2 billion on certain federal, state and foreign tax jurisdiction deferred tax assets to reduce the amount of these assets to the extent necessary to result in an amount that is more likely than not to be realized. The net change in our valuation allowance was a increase of $24 million for the year ended December 31, 2013, and a decrease of $114 million and $50 million for the years ended December 31, 2012 and 2011, respectively; all primarily related to changes in our estimates of our ability to utilize our NOL carryforwards.

As a result of a recent favorable response to an IRS letter ruling request, during the first quarter of 2014, we expect to make an election which will increase the tax basis of certain assets resulting in an increase to our net state deferred tax assets by approximately $18 million with a corresponding decrease in our state income tax expense.

Tangible Property Regulations — On September 13, 2013, the United States Treasury Department and the IRS issued final regulations providing comprehensive guidance on the tax treatment of costs incurred to acquire, repair or improve tangible property. The final regulations are generally effective for taxable years beginning on or after January 1, 2014. On January 24, 2014, the IRS issued procedural guidance pursuant to which taxpayers will be granted automatic consent to change their tax accounting methods to comply with the final regulations. We are currently assessing the future impact of these regulations, but do not anticipate a material impact on our financial condition, results of operations or cash flows.

Unrecognized Tax Benefits

At December 31, 2013, we had unrecognized tax benefits of $68 million. If recognized, $19 million of our unrecognized tax benefits could impact the annual effective tax rate and $49 million, related to deferred tax assets, could be offset against the recorded valuation allowance resulting in no impact to our effective tax rate. We had accrued interest and penalties of $13 million and $24 million for income tax matters at December 31, 2013 and 2012, respectively. We recognize interest and penalties related to unrecognized tax benefits in income tax expense (benefit) on our Consolidated Statements of Operations and recorded $(11) million, $4 million and $1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

A reconciliation of the beginning and ending amounts of our unrecognized tax benefits for the years ended December 31, 2013, 2012 and 2011, is as follows (in millions):

	2013	2012	2011
Balance, beginning of period	$ (92)	$ (74)	$ (88)
Increases related to prior year tax positions	(7)	(19)	—
Decreases related to prior year tax positions	8	1	1
Decreases related to settlements	10	—	—
Decrease related to lapse of statute of limitations	13	—	13
Balance, end of period	$ (68)	$ (92)	$ (74)

U.S. Federal Income Tax Refund

In 2004, we deducted a portion of our foreign dividends as allowed by the IRC when we filed our federal income tax return. Upon further review and analysis, we determined our foreign dividends should have been offset against our current 2004 operating loss. In 2009, we filed an amended federal income tax return that reflected this change and would result in a refund of approximately $10 million. This amended federal return has been under audit by the IRS since it was filed. In October 2012, the IRS approved our amended tax return, and we received a refund of approximately $13 million which included approximately $3 million in accrued interest. The benefit of this refund is reflected in our Consolidated Financial Statements in the fourth quarter of 2012.

11. Earnings (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 the year ended December 31, 2011, diluted loss per share for this period is computed on the same basis as basic loss per share, as the inclusion of any other potential shares outstanding would be anti-dilutive. Reconciliations of the amounts used in the basic and diluted earnings (loss) per common share computations for the years ended December 31, 2013, 2012 and 2011, are as follows (shares in thousands):

	2013	2012	2011
Diluted weighted average shares calculation:			
Weighted average shares outstanding (basic)	440,666	467,752	485,381
Share-based awards	4,107	3,591	—
Weighted average shares outstanding (diluted)	444,773	471,343	485,381

We excluded the following items from diluted earnings (loss) per common share for the years ended December 31, 2013, 2012 and 2011, because they were anti-dilutive (shares in thousands):

	2013	2012	2011
Share-based awards	5,062	10,302	15,260

12. 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 December 31, 2013, there were 567,000 and 40,533,000 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 for our equity classified share-based awards was $34 million, $25 million and $24 million for the years ended December 31, 2013, 2012 and 2011, 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 years ended December 31, 2013, 2012 and 2011. At December 31, 2013, there was unrecognized compensation cost of $1 million related to options, $26 million related to restricted stock and nil related to restricted stock units, which is expected to be recognized over a weighted average period of 0.7 years for options, 1.1 years for restricted stock and 0.4 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 year ended December 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	3,724,411	$	13.70			
Forfeited	—	$	—			
Expired	35,100	$	17.69			
Outstanding — December 31, 2013	14,114,289	$	18.25	3.1	$	36
Exercisable — December 31, 2013	12,475,493	$	18.70	2.5	$	29
Vested and expected to vest – December 31, 2013	14,038,217	$	18.27	3.1	$	36

The total intrinsic value of our employee stock options exercised was $22 million, $1 million and nil for the years ended December 31, 2013, 2012 and 2011, respectively. The total cash proceeds received from our employee stock options exercised was $20 million, $5 million and nil for the years ended December 31, 2013, 2012 and 2011, respectively.

The fair value of options granted during the years ended December 31, 2013, 2012 and 2011, 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	2011
Expected term (in years)(1)	6.5	6.5	6.5
Risk-free interest rate(2)	1.4 %	1.2 – 1.6 %	1.7 – 3.2 %
Expected volatility(3)	25.6 %	27.0 – 30.5 %	31.2 – 44.9 %
Dividend yield(4)	—	—	—
Weighted average grant-date fair value (per option)	$ 5.31	$ 5.18	$ 5.49

(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.

(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.

A summary of our restricted stock and restricted stock unit activity for the Calpine Equity Incentive Plans for the year ended December 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	1,790,448	$	18.47
Forfeited	182,438	$	16.17
Vested	1,310,206	$	12.57
Nonvested — December 31, 2013	4,431,841	$	16.45

The total fair value of our restricted stock and restricted stock units that vested during the years ended December 31, 2013, 2012 and 2011, was approximately $25 million, $20 million and $7 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 was $2 million for the year ended December 31, 2013.

13. Defined Contribution and Defined Benefit Plans

We maintain two defined contribution savings plans that are intended to be tax exempt under Sections 401(a) and 501 (a) of the IRC. Our non-union plan generally covers employees who are not covered by a collective bargaining agreement, and our union plan covers employees who are covered by a collective bargaining agreement. We recorded expenses for these plans of approximately $11 million, $12 million and $10 million for the years ended December 31, 2013, 2012 and 2011, respectively. Employer matching contributions are 100% of the first 5% of compensation a participant defers for the non-union plan. The employee deferral limit is 75% of eligible compensation under both plans.

We also maintain a defined benefit pension plan whereby retirement benefits are primarily a function of age attained, years of participation, years of service, vesting and level of compensation. As of December 31, 2013 and 2012, our pension assets, liabilities and related costs were not material to us. As of December 31, 2013 and 2012, there were approximately $14 million and $12 million in plan assets and approximately $20 million and $21 million in pension liabilities, respectively. Our net pension liability recorded on our Consolidated Balance Sheets as of December 31, 2013 and 2012, was approximately $6 million and $9 million, respectively. For the years ended December 31, 2013, 2012 and 2011, we recognized net periodic benefit costs of approximately $2 million, $1 million and $1 million, respectively. Our net periodic benefit cost is included in plant operating expense on our Consolidated Statements of Operations. As of December 31, 2013 and 2012, the total amount recognized in AOCI for actuarial losses related to pension obligation was approximately $1 million and $5 million, respectively.

In making our estimates of our pension obligation and related costs, we utilize discount rates, rates of compensation increases and rates of return on our assets that we believe are reasonable. Due to relatively small size of our pension liability (which is not considered material), significant changes in these assumptions would not have a material effect on our pension liability. During 2013 and 2012, we made contributions of approximately $1 million and $2 million, respectively, and estimated contributions to the pension plan are expected to be approximately $2 million in 2014. Estimated future benefit payments to participants in each of the next five years are expected to be approximately $1 million in each year.

14. Capital Structure

Common Stock

Pursuant to our Plan of Reorganization, all shares of our common stock outstanding prior to the Effective Date were canceled and the issuance of 485 million new shares of reorganized Calpine Corporation common stock was authorized to resolve allowed unsecured claims. A portion of the 485 million authorized shares was immediately distributed, and the remainder was reserved for distribution to holders of certain disputed claims that, although allowed as of the Effective Date, were unresolved. In June 2011, we settled the largest remaining claim outstanding and began the process of distributing the balance of the reserved shares, which was completed during the third quarter of 2011, pursuant to our Plan of Reorganization.

Our authorized common stock consists of 1.4 billion shares of Calpine Corporation common stock. Common stock issued as of December 31, 2013 and 2012, was 497,841,056 shares and 492,495,100 shares, respectively, at a par value of $0.001 per share. Common stock outstanding as of December 31, 2013 and 2012, was 429,038,988 shares and 457,048,970 shares, respectively. The table below summarizes our common stock activity for the years ended December 31, 2013, 2012 and 2011.

	Shares Issued	Shares Held in Treasury	Shares Held in Reserve	Total
Balance, December 31, 2010	444,883,356	(448,158)	44,258,432	488,693,630
Resolution of claims	44,258,432	—	(44,258,432)	—
Shares issued under Calpine Equity Incentive Plans	1,327,027	(139,846)	—	1,187,181
Share repurchase program	—	(8,137,073)	—	(8,137,073)
Balance, December 31, 2011	490,468,815	(8,725,077)	—	481,743,738
Shares issued under Calpine Equity Incentive Plans	2,026,285	(284,376)	—	1,741,909
Share repurchase program	—	(26,436,677)	—	(26,436,677)
Balance, December 31, 2012	492,495,100	(35,446,130)	—	457,048,970
Shares issued under Calpine Equity Incentive Plans	5,345,956	(2,323,828)	—	3,022,128
Share repurchase program	—	(31,032,110)	—	(31,032,110)
Balance, December 31, 2013	497,841,056	(68,802,068)	—	429,038,988

Treasury Stock

As of December 31, 2013 and 2012, we had treasury stock of 68,802,068 shares and 35,446,130 shares, respectively, with a cost of $1.2 billion and $594 million, respectively. Having previously authorized $600 million in repurchases of our common stock, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock in February 2013 and an additional $100 million in August 2013. Under the aggregate $1.1 billion of authorizations, we repurchased a total of 60,139,816 shares of our outstanding common stock at an average price of $18.29 per share. In November 2013, our Board of Directors authorized a new $1.0 billion multi-year share repurchase program, under which we have repurchased a total of 12,459,919 shares of our common stock for approximately $239 million at an average price of $19.15 per share as of the filing of this Report. Our treasury stock also consists of our common stock withheld to satisfy federal, state and local income tax withholding requirements for vested employee restricted stock awards and net share employee stock options exercises under the Equity Plan. All treasury stock is held at cost.

15. Commitments and Contingencies

Long-Term Service Agreements

As of December 31, 2013, the total estimated commitments for LTSAs associated with turbines installed or in storage were approximately $134 million. These commitments are payable over the terms of the respective agreements, which range from 1 to 12 years. LTSA future commitment estimates are based on the stated payment terms in the contracts at the time of execution and are subject to an annual inflationary adjustment. Certain of these agreements have terms that allow us to cancel the contracts for a fee. If we cancel such contracts, the estimated commitments remaining for LTSAs would be reduced.

Power Plant, Land and Other Operating Leases

We have entered into certain long-term operating leases for power plants, extending through 2020, which include renewal options or purchase options at fair value and contain customary restrictions on dividends up to Calpine Corporation, additional debt and further encumbrances similar to those typically found in project finance agreements. Payments on our operating leases, which may contain escalation clauses or step rent provisions, are recognized on a straight-line basis. Certain capital improvements associated with leased power plants may be deemed to be leasehold improvements and are amortized over the shorter of the term of the lease or the economic life of the capital improvement. We have also entered into various land and other operating leases for ground facilities and operations, which extend through 2069. Future minimum rent payments under these lease agreements, including renewal options and rent escalation clauses, are as follows (in millions):

	Initial Year	2014	2015	2016	2017	2018	Thereafter	Total
Land and other operating leases .	various	$ 15	$ 15	$ 15	$ 15	$ 15	$ 215	$ 290
Power plant operating leases:								
Greenleaf	1998	$ 7	$ 4	$ —	$ —	$ —	$ —	$ 11
KIAC	2000	24	23	22	22	22	30	143
Total power plant leases.................		$ 31	$ 27	$ 22	$ 22	$ 22	$ 30	$ 154
Total leases.......		$ 46	$ 42	$ 37	$ 37	$ 37	$ 245	$ 444

During the years ended December 31, 2013, 2012 and 2011, rent expense for power plant and land and other operating leases amounted to $47 million, $51 million and $53 million, respectively.

Production Royalties and Leases

We are obligated under numerous geothermal leases and right-of-way, easement and surface agreements. The geothermal leases generally provide for royalties based on production revenue with reductions for property taxes paid. The right-of-way, easement and surface agreements are based on flat rates or adjusted based on consumer price index changes and are not material. Under the terms of most geothermal leases, the royalties accrue as a percentage of power revenues. Certain properties also have net profits and overriding royalty interests that are in addition to the land base lease royalties. Some lease agreements contain clauses providing for minimum lease payments to lessors if production temporarily ceases or if production falls below a specified level. Production royalties for geothermal power plants for the years ended December 31, 2013, 2012 and 2011, were $27 million, $22 million and $22 million, respectively.

Office Leases

We lease our corporate and regional offices under noncancelable operating leases extending through 2020. Future minimum lease payments under these leases are as follows (in millions):

2014	$ 11
2015	10
2016	10
2017	11
2018	10
Thereafter	28
Total	$ 80

Lease payments are subject to adjustments for our pro rata portion of annual increases or decreases in building operating costs. During the years ended December 31, 2013, 2012 and 2011, rent expense for noncancelable operating leases was $12 million, $12 million and $13 million, respectively.

Natural Gas Purchases

We enter into natural gas purchase contracts of various terms with third parties to supply natural gas to our natural gas-fired power plants. The majority of our purchases are made in the spot market or under index-priced contracts. These contracts are accounted for as executory contracts and therefore not recognized as liabilities on our Consolidated Balance Sheet. At December 31, 2013, we had future commitments for the purchase, transportation, or storage of commodities as detailed below (in millions):

2014	$	385
2015		290
2016		238
2017		235
2018		224
Thereafter		815
Total	$	2,187

Guarantees and Indemnifications

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

At December 31, 2013, guarantees of subsidiary debt, standby letters of credit and surety bonds to third parties and guarantees of subsidiary operating lease payments and their respective expiration dates were as follows (in millions):

Guarantee Commitments	2014	2015	2016	2017	2018	Thereafter	Total
Guarantee of subsidiary debt[(1)]	$ 36	$ 37	$ 36	$ 26	$ 31	$ 178	$ 344
Standby letters of credit[(2)(4)]	562	11	—	20	—	37	630
Surety bonds[(3)(4)(5)]	—	—	—	—	—	27	27
Guarantee of subsidiary operating lease payments[(4)]	7	4	—	—	—	—	11
Total	$ 605	$ 52	$ 36	$ 46	$ 31	$ 242	$ 1,012

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

(2) The standby letters of credit disclosed above represent those disclosed in Note 6.

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

(4) These are contingent off balance sheet obligations.

(5) As of December 31, 2013, $4 million of cash collateral is outstanding related to these bonds.

We routinely arrange for the issuance of letters of credit and various forms of surety bonds to third parties in support of our subsidiaries' contractual arrangements of the types described above and may guarantee the operating performance of some of our partially-owned subsidiaries up to our ownership percentage. The letters of credit issued under various credit facilities support CES risk management and other operational and construction activities. In the event a subsidiary were to fail to perform its obligations under a contract supported by such a letter of credit or surety bond, and the issuing bank or surety were to make payment to the third party, we would be responsible for reimbursing the issuing bank or surety within an agreed timeframe, typically a period of one to ten days. To the extent liabilities are incurred as a result of activities covered by letters of credit or the surety bonds, such liabilities are included on our Consolidated Balance Sheets.

Commercial Agreements — In connection with the purchase and sale of power, natural gas and emission allowances to and from third parties with respect to the operation of our power plants, we may be required to guarantee a portion of the obligations of certain of our subsidiaries. These guarantees may include future payment obligations and effectively guarantee our future performance under certain agreements.

Asset Acquisition and Disposition Agreements — In connection with our purchase and sale agreements, we have frequently provided for indemnification to the counterparty for liabilities incurred as a result of a breach of a representation, warranty or covenant by the indemnifying party. These indemnification obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or impossible to quantify at the time of the consummation of a particular transaction.

Other — Additionally, we and our subsidiaries from time to time assume other guarantee and indemnification obligations in conjunction with other transactions such as parts supply agreements, construction agreements, maintenance and service agreements and equipment lease agreements. These guarantee and indemnification obligations may include indemnification from personal injury or other claims by our employees as well as future payment obligations and effectively guarantee our future performance under certain agreements.

Our potential exposure under guarantee and indemnification obligations can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. Our total maximum exposure under our guarantee and indemnification obligations is not estimable due to uncertainty as to whether claims will be made or how any potential claim will be resolved. As of December 31, 2013, there are no material outstanding claims related to our guarantee and indemnification obligations and we do not anticipate that we will be required to make any material payments under our guarantee and indemnification obligations.

Litigation

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

16. Segment and Significant Customer Information

We assess our business on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and other factors impacting supply and demand. At December 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).

	Year Ended December 31, 2013					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$ 1,937	$ 2,347	$ 1,356	$ 661	$ —	$ 6,301
Intersegment revenues	5	(4)	33	189	(223)	—
Total operating revenues	$ 1,942	$ 2,343	$ 1,389	$ 850	$ (223)	$ 6,301
Commodity Margin	$ 1,020	$ 632	$ 712	$ 204	$ —	$ 2,568
Add: Unrealized mark-to-market commodity activity, net and other[1]	(50)	51	5	22	(31)	(3)
Less:						
Plant operating expense	365	269	172	120	(31)	895
Depreciation and amortization expense	243	165	130	73	(2)	609
Sales, general and other administrative expense	37	56	21	21	1	136
Other operating expenses	45	3	29	4	—	81
(Income) from unconsolidated investments in power plants	—	—	(30)	—	—	(30)
Income from operations	280	190	395	8	1	874
Interest expense, net of interest income						690
Debt extinguishment costs and other (income) expense, net						164
Income before income taxes						$ 20

	Year Ended December 31, 2012					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$ 1,668	$ 1,857	$ 1,280	$ 673	$ —	$ 5,478
Intersegment revenues	10	61	14	80	(165)	—
Total operating revenues	$ 1,678	$ 1,918	$ 1,294	$ 753	$ (165)	$ 5,478
Commodity Margin[2][3]	$ 994	$ 570	$ 729	$ 245	$ —	$ 2,538
Add: Unrealized mark-to-market commodity activity, net and other[1]	(93)	87	(14)	(33)	(31)	(84)
Less:						
Plant operating expense	368	247	206	131	(30)	922
Depreciation and amortization expense	203	142	134	85	(2)	562
Sales, general and other administrative expense	36	47	28	29	—	140
Other operating expenses	42	5	29	5	(3)	78
(Gain) on sale of assets, net	—	—	(7)	(215)	—	(222)
(Income) from unconsolidated investments in power plants	—	—	(28)	—	—	(28)
Income from operations	252	216	353	177	4	1,002
Interest expense, net of interest income						725
Loss on interest rate derivatives						14
Debt extinguishment costs and other (income) expense, net						45
Income before income taxes						$ 218

	Year Ended December 31, 2011					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$ 2,372	$ 2,306	$ 1,336	$ 786	$ —	$ 6,800
Intersegment revenues	12	23	7	135	(177)	—
Total operating revenues	$ 2,384	$ 2,329	$ 1,343	$ 921	$ (177)	$ 6,800
Commodity Margin(2)(3)	$ 1,061	$ 469	$ 704	$ 240	$ —	$ 2,474
Add: Unrealized mark-to-market commodity activity, net and other(1)	113	(102)	(13)	1	(32)	(33)
Less:						
Plant operating expense	380	235	177	141	(29)	904
Depreciation and amortization expense	192	135	138	90	(5)	550
Sales, general and other administrative expense	43	43	24	22	(1)	131
Other operating expenses	41	3	30	5	(2)	77
(Income) from unconsolidated investments in power plants	—	—	(21)	—	—	(21)
Income (loss) from operations	518	(49)	343	(17)	5	800
Interest expense, net of interest income						751
Loss on interest rate derivatives						145
Debt extinguishment costs and other (income) expense, net						115
Loss before income taxes						$ (211)

(1) Includes $6 million, $1 million and $12 million of lease levelization and $14 million, $14 million and $8 million of amortization expense for the years ended December 31, 2013, 2012 and 2011, respectively.

(2) Our North segment includes Commodity Margin of $73 million and $70 million for the years ended December 31, 2012 and 2011, respectively, related to Riverside Energy Center, LLC, which was sold in December 2012.

(3) Our Southeast segment includes Commodity Margin of $52 million and $51 million for the years ended December 31, 2012 and 2011, respectively, related to Broad River, which was sold in December 2012.

Significant Customers

For the year ended December 31, 2013, we had two significant customers that individually accounted for more than 10% of our annual consolidated revenues, PJM Settlement, Inc. and PG&E. For the years ended December 31, 2012 and 2011, we only had one significant customer that individually accounted for more than 10% of our annual consolidated revenues, PJM Settlement, Inc. Our revenues from PJM Settlement, Inc. for the years ended December 31, 2013, 2012 and 2011 were approximately $820 million, $713 million and $742 million, respectively, and were attributed to our North segment. Our revenues from PG&E were approximately $694 million for the year ended December 31, 2013 and were attributed to our West segment. As of December 31, 2013 and 2012, our receivables from PJM Settlement, Inc. were approximately $26 million and $37 million, respectively. As of December 31, 2013, our receivables from PG&E were approximately $83 million.

17. Quarterly Consolidated Financial Data (unaudited)

Our quarterly operating results have fluctuated in the past and may continue to do so in the future as a result of a number of factors, including, but not limited to, our restructuring activities (including asset sales), the completion of development projects, the timing and amount of curtailment of operations under the terms of certain PPAs, the degree of risk management and marketing, hedging and optimization activities, energy commodity market prices and variations in levels of production. Furthermore, the majority of the dollar value of capacity payments under certain of our PPAs are received during the months of May through October.

	Quarter Ended			
	December 31	September 30	June 30	March 31
	(in millions, except per share amounts)			
2013				
Operating revenues	$ 1,438	$ 2,050	$ 1,572	$ 1,241
Income from operations	$ 151	$ 597	$ 122	$ 4
Net income (loss) attributable to Calpine	$ (97)	$ 306	$ (70)	$ (125)
Net income (loss) per common share attributable to Calpine — Basic	$ (0.23)	$ 0.70	$ (0.16)	$ (0.28)
Net income (loss) per common share attributable to Calpine — Diluted	$ (0.23)	$ 0.70	$ (0.16)	$ (0.28)
2012				
Operating revenues	$ 1,367	$ 1,996	$ 879	$ 1,236
Income (loss) from operations	$ 295	$ 705	$ (193)	$ 195
Net income (loss) attributable to Calpine	$ 100	$ 437	$ (329)	$ (9)
Net income (loss) per common share attributable to Calpine — Basic	$ 0.22	$ 0.95	$ (0.69)	$ (0.02)
Net income (loss) per common share attributable to Calpine — Diluted	$ 0.22	$ 0.94	$ (0.69)	$ (0.02)

CALPINE CORPORATION AND SUBSIDIARIES

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Year	Charged to Expense	Charged to Other Accounts	Deductions[1]	Balance at End of Year
			(in millions)		
Year ended December 31, 2013					
Allowance for doubtful accounts	$ 6	$ 4	$ (5)	$ —	$ 5
Deferred tax asset valuation allowance	2,222	24	—	—	2,246
Year ended December 31, 2012					
Allowance for doubtful accounts	$ 13	$ (1)	$ (1)	$ (5)	$ 6
Deferred tax asset valuation allowance	2,336	(114)	—	—	2,222
Year ended December 31, 2011					
Allowance for doubtful accounts	$ 2	$ 7	$ 4	$ —	$ 13
Deferred tax asset valuation allowance	2,386	(50)	—	—	2,336

(1) Represents write-offs of accounts considered to be uncollectible and previously reserved.

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ANNEX

ANNEX A

REGULATION G RECONCILIATIONS

Adjusted EBITDA represents net income (loss) attributable to Calpine before net (income) loss attributable to the noncontrolling interest, interest, taxes, depreciation and amortization, adjusted for certain non-cash and non-recurring items as detailed in the following reconciliation. Adjusted EBITDA is not intended to represent cash flows from operations or net income (loss) as defined by U.S. GAAP as an indicator of operating performance and is not necessarily comparable to similarly titled measures reported by other companies.

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

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

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

Adjusted Free Cash Flow represents net income before interest, taxes, depreciation and amortization, as adjusted to reflect Adjusted EBITDA described above, less operating lease payments, major maintenance expense and maintenance capital expenditures, net cash interest, cash taxes and other adjustments, including non-recurring items. Adjusted Free Cash Flow is presented because we believe it is a useful tool for assessing the financial performance of our company in the current period. Adjusted Free Cash Flow is a performance measure and is not intended to represent net income (loss), the most directly comparable U.S. GAAP measure, or liquidity and is not necessarily comparable to similarly titled measures reported by other companies.

Consolidated Adjusted EBITDA Reconciliation

In the following table, we have reconciled our Adjusted EBITDA and Adjusted Free Cash Flow to our net income (loss) attributable to Calpine for the years ended December 31, 2013, 2012 and 2011, as reported under U.S. GAAP.

	Year Ended December 31,		
	2013	**2012**	**2011**
Net income (loss) attributable to Calpine	$ 14	$ 199	$ (190)
Net income attributable to the noncontrolling interest	4	—	1
Income tax expense (benefit)	2	19	(22)
Debt extinguishment costs and other (income) expense, net	164	45	115
Loss on interest rate derivatives	—	14	145
Interest expense, net of interest income	690	725	751
Income from operations	$ 874	$ 1,002	$ 800
Add:			
Adjustments to reconcile income from operations to Adjusted EBITDA:			
Depreciation and amortization expense, excluding deferred financing costs[(1)]	609	564	552
Major maintenance expense	224	200	205
Operating lease expense	35	34	35
Unrealized loss on commodity derivative mark-to-market activity	14	82	25
(Gain) on sale of assets, net	—	(222)	—
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude the noncontrolling interest	14	31	36
Stock-based compensation expense	36	25	24
Loss on dispositions of assets	4	12	16
Acquired contract amortization	14	14	8
Other	6	7	25
Total Adjusted EBITDA	$ 1,830	$ 1,749	$ 1,726
Less:			
Operating lease payments	34	34	35
Major maintenance expense and capital expenditures[(2)]	392	375	397
Cash interest, net[(3)]	700	757	781
Cash taxes	19	11	13
Other	8	8	11
Adjusted Free Cash Flow[(4)]	$ 677	$ 564	$ 489
Weighted average shares of common stock outstanding (diluted, in thousands)	444,773	471,343	485,381
Adjusted Free Cash Flow Per Share (diluted)	$ 1.52	$ 1.20	$ 1.01

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

(2) Includes $228 million, $192 million and $201 million in major maintenance expense for the years ended December 31, 2013, 2012 and 2011, respectively, and $164 million, $183 million and $196 million in maintenance capital expenditure for the years ended December 31, 2013, 2012 and 2011, respectively.

(3) Includes commitment, letter of credit and other bank fees from both consolidated and unconsolidated investments, net of capitalized interest and interest income.

(4) Excludes an increase in working capital of $130 million, a decrease in working capital of $107 million and an increase in working capital of $13 million for the years ended December 31, 2013, 2012 and 2011, respectively. Adjusted Free Cash Flow, as reported, excludes changes in working capital, such that it is calculated on the same basis as our guidance.

Board of Directors (as of April 1, 2014)

J. Stuart Ryan [N]
Chairman of the Board
Chairman, Aggregates USA and Founding Owner and President, Rydout LLC

Frank Cassidy [C]
Retired President and Chief Operating Officer
PSEG Power LLC

Jack A. Fusco
Chief Executive Officer, Calpine Corp.

Robert C. Hinckley [A][N]
Chairman and Managing Director, MCL Intellectual Property LLC

Michael W. Hofmann [A][C]
Retired Vice President and Chief Risk Officer
Koch Industries, Inc.

David C. Merritt [A]
Owner, BC Partners, Inc.

W. Benjamin Moreland [A]
President and Chief Executive Officer
Crown Castle International Corp.

Robert A. Mosbacher, Jr. [C][N]
Chairman, Mosbacher Energy Company

Denise M. O'Leary [C][N]
Private Venture Capital Investor

[A] Audit Committee
[C] Compensation Committee
[N] Nominating and Governance Committee

Executive Management (as of April 1, 2014)

Jack A. Fusco
Chief Executive Officer

John B. (Thad) Hill
President and Chief Operating Officer

Zamir Rauf
Executive Vice President and Chief Financial Officer

W. Thaddeus Miller
Executive Vice President, Chief Legal Officer and Corporate Secretary

John M. Adams
Executive Vice President, Power Operations

Steven D. Pruett
Executive Vice President, Commercial Operations

General Information

Corporate Headquarters
Calpine Corporation
717 Texas Avenue, Suite 1000
Houston, Texas 77002
(713) 830-2000
www.calpine.com

Investor Relations
Calpine Corporation Investor Relations
(713) 830-8775
investor-relations@calpine.com

Independent Auditor
Pricewaterhouse Coopers LLP
Houston, Texas

Transfer Agent
Computershare, Inc.
P.O. Box 30170
College Station, Texas 77842-3170
(877) 745-9351

Stock Information
Calpine Corporation's common stock is listed on the NYSE under the symbol CPN.

Form 10-K
The Company's Annual Report on Form 10-K for the year ended December 31, 2013, as filed with the Securities and Exchange Commission, is included in this report. Additional copies may be obtained without charge by writing:

Calpine Corporation
Attn: Investor Relations
717 Texas Avenue, Suite 1000
Houston, Texas 77002

Annual Meeting
The Annual Meeting of Shareholders of Calpine Corporation will be held on Wednesday, May 14, 2014, at 8 a.m. Central Time at our corporate offices located at 717 Texas Ave., 10th floor, Houston, TX 77002. All shareholders are cordially invited to attend.

Forward-Looking Statement
Certain statements made in this Annual Report by or on behalf of the Company that are not historical facts are intended to be forward-looking statements within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These statements are based on assumptions that the Company believes are reasonable; however, many important factors, as discussed under "Forward-Looking Statements" in the Company's Form 10-K for the year ended December 31, 2013, could cause the Company's results in the future to differ materially from the forward-looking statements made herein and in any other documents or oral presentations made by or on behalf of the Company.

Calpine Corporation
717 Texas Avenue, Suite 1000
Houston, Texas 77002
(713) 830-2000

WWW.CALPINE.COM