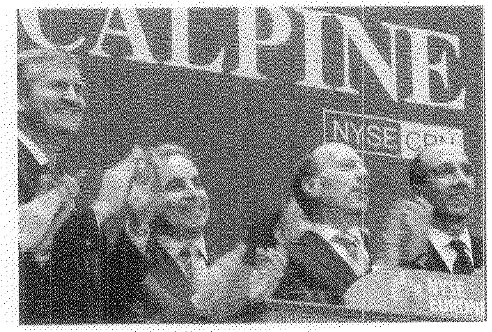
CALPINE®

NYSE CPN

2012 ANNUAL REPORT

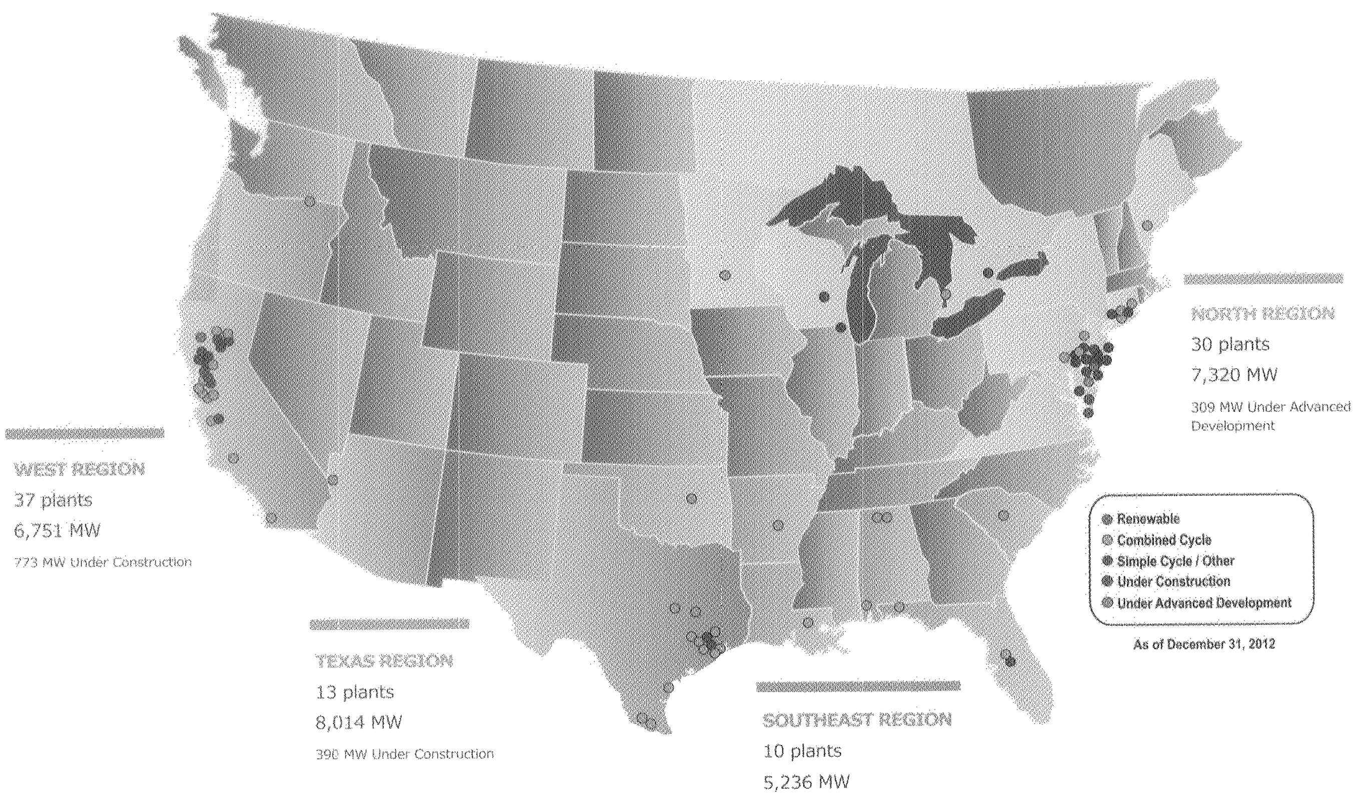


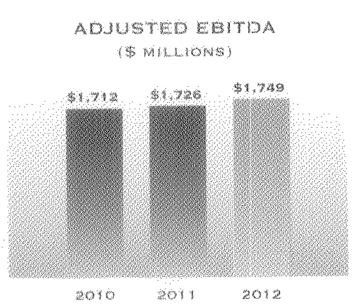
Calpine's management team rings the closing bell at the New York Stock Exchange (L to R): Thad Hill (President and COO), Jack Fusco (CEO), Thad Miller (EVP and CLO) and Zamir Rauf (EVP and CFO).

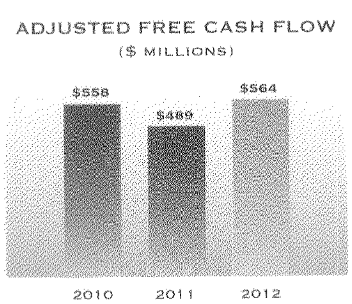
Delivering Effective Capital Allocation

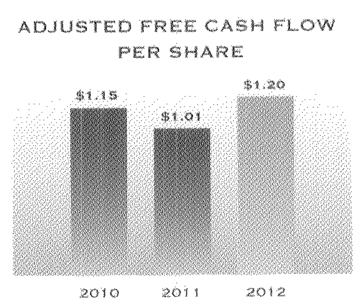
As a management team, we are committed to being good stewards of your capital. Our goal is to deliver Adjusted Free Cash Flow Per Share growth of 15 – 20% compounded annually. We strive to do this by identifying high-return growth projects while also opportunistically repurchasing our stock, which we believe represents an investment in clean, efficient and flexible natural gas-fired generation at attractive prices. 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 27,000 MW in Operation

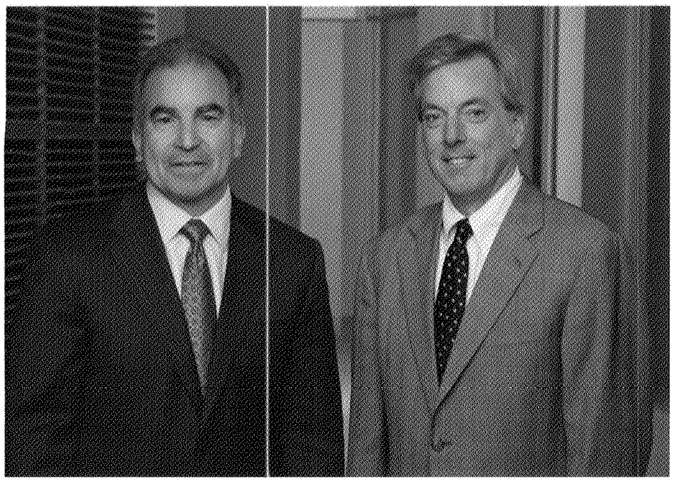








All MW figures shown represent Calpine's net ownership interest.



Fellow Shareholders,

Calpine continues to capitalize on America's shift toward greater utilization of cleaner and more affordable power generated by modern, efficient and flexible natural gas-fired power plants.

This secular shift represents the culmination of a series of transformational forces that have been driving the power generation industry for a decade:

- America stands to benefit from an abundant and affordable supply of clean-burning, domestic natural gas as a result of technological advancements in drilling. Calpine's power plants are reliable and efficient and have a competitive cost advantage in most markets. Meanwhile, nuclear and coal-fired power plants are challenged in this sustained low natural gas price environment.
- America's electricity infrastructure is old and in need of more than $1 trillion of new investment. Older coal- and oil-fired power plants are facing retirement due to the prohibitive cost of required environmental upgrades, as well as the challenging economics of aging, inefficient plants.
- Permitting and siting issues are expensive and add significant time to the power plant development cycle. This effectively creates a barrier to entry for a number of years, benefiting our existing portfolio as the economy recovers.
- Finally, as grid operators seek to integrate intermittent renewable power from wind and solar – especially in California – the flexibility of our existing power plants should realize greater value by providing reliable, dispatchable electricity.

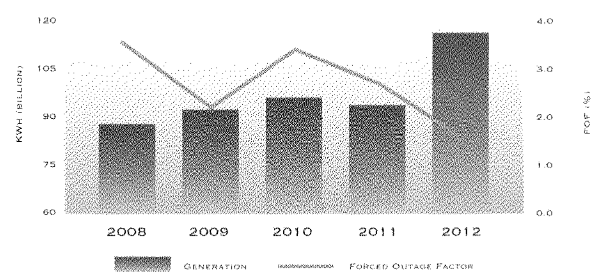
Our clean, efficient, modern and flexible fleet is uniquely positioned to benefit from these trends. In short, Calpine is double-levered to economic recovery as our volume of electricity produced rises and electricity prices increase due to increasing demand and reductions in supply from retiring coal, oil and nuclear units.

With these favorable secular trends as our backdrop, we remain committed to further enhancing Calpine's position as a leader in the industry, with particular focus on the following management priorities.

Premier Power Generation Company

2012 was a breakout year for Calpine – our combined-cycle plant utilization rate (known as capacity factor) was 52%, up nearly 23% over 2011 and the highest it has been in a decade. Our fleet generated a record 116 billion kWh of electricity, making us one of the nation's largest suppliers of wholesale electricity. Despite increased generation, we decreased our major maintenance cost and held the line on operating expenses, due in large part to our continued focus on operational excellence and preventive maintenance, which yielded our lowest ever fleetwide forced outage factor. Our employees achieved these accomplishments while continuing to demonstrate Calpine's strong commitment to workplace safety.

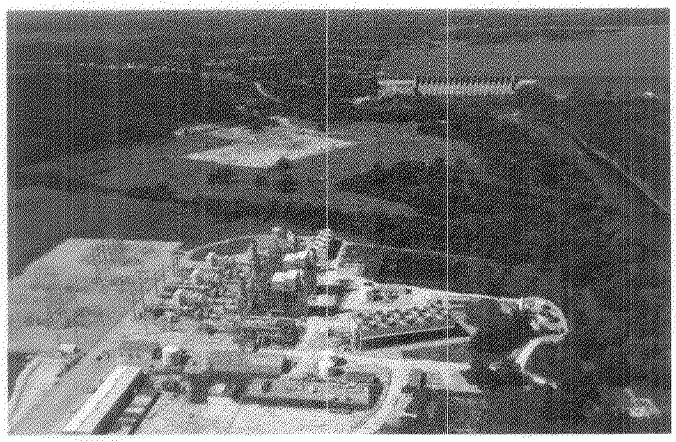
Improving Operations while Increasing Generation



In 2012, Calpine produced approximately 116 billion kWh of affordable, reliable electricity for our customers, making us one of the nation's largest suppliers of wholesale power.

Our pride in the Calpine team doesn't stop at these on-the-job feats. We kicked off an employee wellness initiative that has already improved the lives of our employees and the communities in which we live and operate. Calpine's community involvement reached new heights last year, as we sponsored 86 cyclists in the MS150 race from Houston to Austin and 121 runners in the Houston Marathon and Half-Marathon. When combined with our ongoing work with holiday drives, food banks, Earth Day, Astro's Community Leaders and other similar efforts throughout the company, these initiatives enabled us to contribute more than $1 million to our communities in 2012.

Our thanks and congratulations go out to the entire Calpine team for all of these achievements.



Bosque Energy Center, Texas

MARKET ADVOCACY

Calpine is committed to advancing the principles of competitive wholesale power markets. We advocate at the federal and state levels for market-driven solutions in wholesale capacity and energy markets that result in nondiscriminatory, transparent forward price signals in order to encourage economic investment in affordable, flexible, clean and reliable electric supply. During 2012, our advocacy efforts concentrated on:

- Preserving competitive organized markets that prevent discrimination between new and existing generation and create stable pricing signals that encourage necessary investment
- Preventing the proliferation of subsidized generation and instead allowing the markets (not administrators) to select "winners", and
- Leveling the playing field between generation resources and demand response providers, who are currently subject to less stringent performance requirements yet receive similar compensation.

Russell City Energy Center, California

We have made progress on some fronts and while others progress more slowly, there is momentum in the right direction, and we are committed to being at the forefront of advocacy on these issues in 2013.

CAPITAL ALLOCATION

We have committed to be good stewards of your capital. Last year, Calpine built upon its track record of effective capital allocation on all fronts, including asset monetization, divestiture and acquisition, disciplined growth and share repurchases. Along these lines, we:

- Divested at attractive prices two power plants in South Carolina and Wisconsin for approximately $825 million, resulting in a $222 million gain
- Acquired the 800 MW Bosque Energy Center in Texas for $432 million, a significant discount to replacement cost
- Advanced the construction and development of five projects totaling approximately 1,600 MW of efficient combined-cycle capacity in California, Texas and Delaware, which we expect to come online between 2013 and 2015
- Repurchased for $600 million approximately 7.25% of our common stock (from November 2011 to January 2013), and
- Preserved Calpine's financial flexibility and strength by maintaining a healthy balance sheet, robust liquidity (approximately $2.3 billion at the end of 2012) and minimal near-term debt maturities.

We also announced that we are targeting Adjusted Free Cash Flow Per Share growth of 15 – 20% compounded annually. Our capital allocation decisions will be centered around this goal.

Looking to 2013, our efforts will remain concentrated on these three management priorities – continuously improving the premier power generation company, advancing competitive electricity markets and optimizing capital allocation – which we believe are imperative to our success. We are resolved to focus on what we do best, which is operating natural gas-fired and geothermal power plants. In doing so, we will be innovative, opportunistic and nimble, and we will strive to maintain our competitive edge.

Thank you for your continued support of Calpine.

Sincerely,

J. Stuart Ryan
Chairman of the Board

Jack A. Fusco
Chief Executive Officer

CALPINE®

NYSE CPN

2012 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, 2012

[ ] **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. [ ]

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, 2012, the last business day of the registrant's most recently completed second fiscal quarter: approximately $5,484 million.

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

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: Calpine Corporation: 456,236,512 shares of common stock, par value $0.001, were outstanding as of February 11, 2013.

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 2013 Annual Meeting of Shareholders are incorporated by reference into Part III (Items 11, 12, 13, 14 and portions of Item 10)

CALPINE CORPORATION AND SUBSIDIARIES

FORM 10-K

ANNUAL REPORT
For the Year Ended December 31, 2012

TABLE OF CONTENTS

DEFINITIONS

As used in this Report, the following abbreviations and terms have the meanings as listed below. Additionally, the terms "Calpine," "we," "us" and "our" refer to Calpine Corporation and its consolidated subsidiaries, unless the context clearly indicates otherwise. 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, of which 10% of the aggregate principal amount was redeemed on November 7, 2012 in connection with the issuance of the 2019 First Lien Term Loan
2018 First Lien Term Loans	Collectively, the $1.3 billion first lien senior secured term loan dated March 9, 2011 and the $360 million first lien senior secured term loan dated June 17, 2011
2019 First Lien Notes	The $400 million aggregate principal amount of 8.0% senior secured notes due 2019, issued May 25, 2010, of which 10% of the aggregate principal amount was redeemed on November 7, 2012 in connection with the issuance of the 2019 First Lien Term Loan
2019 First Lien Term Loan	The $835 million first lien senior secured term loan, dated October 9, 2012, among Calpine Corporation, as borrower, and the lenders party hereto, and Morgan Stanley Senior Funding, Inc., as administrative agent and Goldman Sachs Credit Partners L.P., as collateral agent
2020 First Lien Notes	The $1.1 billion aggregate principal amount of 7.875% senior secured notes due 2020, issued July 23, 2010, of which 10% of the aggregate principal amount was redeemed on November 7, 2012 in connection with the issuance of the 2019 First Lien Term Loan
2021 First Lien Notes	The $2.0 billion aggregate principal amount of 7.50% senior secured notes due 2021, issued October 22, 2010, of which 10% of the aggregate principal amount was redeemed on November 7, 2012 in connection with the issuance of the 2019 First Lien Term Loan
2023 First Lien Notes	The $1.2 billion aggregate principal amount of 7.875% senior secured notes due 2023, issued January 14, 2011, of which 10% of the aggregate principal amount was redeemed on November 7, 2012 in connection with the issuance of the 2019 First Lien Term Loan
AB 32	California Assembly Bill 32
Adjusted EBITDA	EBITDA as adjusted for the effects of (a) impairment charges, (b) major maintenance expense, (c) operating lease expense, (d) unrealized gains or losses on commodity derivative mark-to-market activity, (e) adjustments to reflect only the Adjusted EBITDA from our unconsolidated investments, (f) stock-based compensation expense, (g) gains or losses on sales, dispositions or retirements of assets, (h) non-cash gains and losses from foreign currency translations, (i) gains or losses on the repurchase or extinguishment of debt, (j) Conectiv Acquisition-related costs, (k) Adjusted EBITDA from our discontinued operations and (l) extraordinary, unusual or non-recurring items
AOCI	Accumulated Other Comprehensive Income
Average availability	Represents the total hours during the period that our plants were in-service or available for service as a percentage of the total hours in the period
Average capacity factor, excluding peakers	A measure of total actual generation as a percent of total potential generation. It is calculated by dividing (a) total MWh generated by our power plants, excluding peakers, by (b) the product of multiplying (i) the average total MW in operation, excluding peakers, during the period by (ii) the total hours in the period
Bankruptcy Code	U.S. Bankruptcy Code
Bcf	Billion cubic feet

ABBREVIATION	DEFINITION
Blue Spruce	Blue Spruce Energy Center, LLC, formerly an indirect, wholly-owned subsidiary of Calpine that owned Blue Spruce Energy Center, a 310 MW natural gas-fired, peaking power plant located in Aurora, Colorado, which was sold on December 6, 2010
Broad River	Broad River Energy LLC, formerly an indirect, wholly-owned subsidiary of Calpine that leases the Broad River Energy Center, an 847 MW natural gas-fired, peaking power plant located in Gaffney, South Carolina, from the BR Owner Lessors
Broad River Entities	Collectively, Broad River and the BR Owner Lessors
BR Owner Lessors	Broad River OL-1, LLC, a Delaware limited liability company, Broad River OL-2, LLC, a Delaware limited liability company, Broad River OL-3, LLC, a Delaware limited liability company, and Broad River OL-4, LLC, a Delaware limited liability company, each of which is an indirect, wholly-owned subsidiary of Calpine, which lease the Broad River Energy Center (i) from Cherokee County, South Carolina and (ii) to Broad River
Btu	British thermal unit(s), a measure of heat content
CAA	Federal Clean Air Act, U.S. Code Title 42, Chapter 85
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
Calpine BRSP	Calpine BRSP, LLC
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 Guarantors	Hermiston Power LLC and Brazos Valley Energy LLC, wholly-owned subsidiaries of CCFC
CCFC Notes	The $1.0 billion aggregate principal amount of 8.0% Senior Secured Notes due 2016 issued May 19, 2009, by CCFC and CCFC Finance
CDHI	Calpine Development Holdings, Inc., an indirect, wholly-owned subsidiary of Calpine
CEHC	Conectiv Energy Holding Company, LLC, a wholly-owned subsidiary of Conectiv
CES	Calpine Energy Services, L.P.

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, RGGI compliance and other environmental costs 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, RGGI compliance and other environmental costs, 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
Conectiv	Conectiv, LLC, a wholly-owned subsidiary of PHI
Conectiv Acquisition	The acquisition of all of the membership interests in CEHC pursuant to the Conectiv Purchase Agreement on July 1, 2010, whereby we acquired all of the power generation assets of Conectiv from PHI, which included 18 operating power plants and York Energy Center that was under construction and achieved COD on March 2, 2011, with 4,491 MW of capacity
Conectiv Purchase Agreement	Purchase Agreement by and among PHI, Conectiv, CEHC and NDH dated as of April 20, 2010
Corporate Revolving Facility	The $1.0 billion aggregate amount revolving credit facility credit agreement, dated as of December 10, 2010, among Calpine Corporation, Goldman Sachs Bank USA, as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, the lenders party thereto and the other parties thereto
CPUC	California Public Utilities Commission
Creed	Creed Energy Center, LLC
Director Plan	The Amended and Restated Calpine Corporation 2008 Director Incentive Plan
Dodd-Frank Act	The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
EBITDA	Net income (loss) attributable to Calpine before net (income) loss attributable to the noncontrolling interest, interest, taxes, depreciation and amortization
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 and the 2023 First Lien Notes
First Lien Term Loans	Collectively, the 2018 First Lien Term Loans and the 2019 First Lien Term Loan
FRCC	Florida Reliability Coordinating Council
Freestone	Freestone Energy Center, a 994 MW natural gas-fired, combined-cycle power plant located near Fairfield, Texas
GE	General Electric International, Inc.
GEC	Collectively, Gilroy Energy Center, LLC, Creed and Goose Haven
Geysers Assets	Our geothermal power plant assets, including our steam extraction and gathering assets, located in northern California consisting of 15 operating power plants and one plant not in operation
GHG(s)	Greenhouse gas(es), primarily carbon dioxide (CO_2), and including methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs)
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
IOUs	Investor Owned Utilities
IRC	Internal Revenue Code
IRS	U.S. Internal Revenue Service
ISO(s)	Independent System Operator(s)
ISO-NE	ISO New England
ISRA	Industrial Site Recovery Act
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
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 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
PHI	Pepco Holdings, Inc.
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, 2012, filed with the SEC on February 12, 2013
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)
Rocky Mountain	Rocky Mountain Energy Center, LLC, formerly an indirect, wholly-owned subsidiary of Calpine that owned Rocky Mountain Energy Center, a 621 MW natural gas-fired, combined-cycle power plant located in Keenesburg, Colorado, which was sold on December 6, 2010
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
South Point	South Point Energy Center, a 530 MW natural gas-fired, combined-cycle power plant located in Mohave Valley, Arizona
Spark Spread(s)	The difference between the sales price of power per MWh and the cost of fuel to produce it
SPP	Southwest Power Pool
Steam Adjusted Heat Rate	The adjusted Heat Rate for our natural gas-fired power plants, excluding peakers, calculated by dividing (a) the fuel consumed in Btu reduced by the net equivalent Btu in steam exported to a third party by (b) the KWh generated. Steam Adjusted Heat Rate is a measure of fuel efficiency, so the lower our Steam Adjusted Heat Rate, the lower our cost of generation
TCEQ	Texas Commission on Environmental Quality
TRE	Texas Reliability Entity, Inc.
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 the Whitby 50 MW natural gas-fired, simple-cycle cogeneration power plant located in Ontario, Canada

ABBREVIATION	DEFINITION
WP&L...	Wisconsin Power & Light Company
York Energy Center.........................	565 MW dual fuel, combined-cycle generation power plant (formerly known as the Delta Project) located in Peach Bottom Township, Pennsylvania which achieved COD on March 2, 2011

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

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 with 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, effectively executing our hedging strategy, our customer origination program and completing our growth capital projects on schedule and on budget. 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 2011. 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 92 power plants, including 4 under construction (1 new power plant and 3 expansions of existing power plants), located throughout 20 states in the U.S. and Canada, with an aggregate generation capacity of 27,321 MW and 1,163 MW under construction. Our fleet, including projects under construction, consists of 74 combustion turbine-based plants, 2 fossil steam-based plants, 15 geothermal turbine-based plants and 1 photovoltaic solar plant. In 2012, our fleet of power plants produced approximately 116 billion KWh of electric power for our customers. In addition, we are one of the largest consumers of natural gas in North America. In 2012, we consumed 867 Bcf or approximately 9% of the total estimated natural gas consumed for power generation in the U.S. We believe that having scale and geographic diversity is important in our business. Scale provides us 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 allows us to develop and offer a wide array of products and services to our customers. Geographic diversity helps us manage weather, regulatory and regional economic differences across our markets.

The environmental profile of our power plants reflects our commitment to environmental leadership and stewardship. We have invested the necessary capital to develop a power generation portfolio that has substantially lower air pollutant emissions compared to our competitors' power plants using other fossil fuels, such as coal. In addition, we strive to preserve our nation's valuable water and land resources. To condense steam, our combined-cycle power plants use cooling towers with a closed water cooling system or air cooled condensers and do not employ "once-through" water cooling, which uses large quantities of water from adjacent waterways, negatively impacting aquatic life. Since our plants are modern and efficient and utilize clean burning natural gas, we do not require large areas of land for our power plants nor do we require large specialized landfills for the disposal of coal ash or nuclear plant waste. We believe that we will be less adversely impacted by Cap-and-trade limits, carbon taxes or required environmental upgrades as a result of future potential regulation or legislation addressing GHG, other air pollutant emissions 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 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 wholesale power 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 Becoming the 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.
   - We produced approximately 116 billion KWh of electricity in 2012, 23% more than the same period in 2011 (includes generation from power plants owned but not operated by us and our share of generation from our unconsolidated power plants).
   - Our entire fleet achieved a forced outage factor of 1.6% in 2012, our lowest on record and an improvement of 36% from 2011.
   - Our entire fleet achieved an impressive starting reliability of 98.3% in 2012.
   - During 2012, our outage services subsidiary completed 11 major inspections and 19 hot gas path inspections.
   - For the past twelve consecutive years, our Geysers Assets have reliably generated approximately 6 million MWh per year and, in 2012, achieved an exceptional availability factor of approximately 97%.
2. *Focus on Enhancing Shareholder Value* — We continue to make significant progress to deliver financially disciplined growth, to enhance shareholder value through our capital allocation and share repurchases and to set the foundation for continued 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, 2012 was marked by the following accomplishments:
   - As of the filing of this Report, we have completed our previously announced $600 million share repurchase program, having repurchased a total of 35,568,833 shares of our outstanding common stock at an average price paid of $16.87 per share. In February 2013, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock, bringing the cumulative authorization total to $1.0 billion.
   - During the first quarter of 2012, we terminated our legacy interest rate swaps formerly hedging our First Lien Credit Facility for a payment of approximately $156 million which eliminated our exposure from these instruments to further declines in interest rates.
   - On October 9, 2012, we issued our 2019 First Lien Term Loan and used the proceeds to reduce our overall cost of debt and simplify our capital structure by redeeming a portion of our First Lien Notes and repaying project debt.
   - On November 7, 2012, we completed the purchase of a modern, natural gas-fired, combined-cycle power plant with a nameplate capacity of 800 MW located in Bosque County, Texas for approximately $432 million which increased capacity in our Texas segment.
   - 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 expect to use the sale proceeds for our capital allocation activities and for general corporate purposes.
   - On December 31, 2012, we completed the sale of Riverside Energy Center, LLC to WP&L for approximately $402 million. We expect to use the sale proceeds for our capital allocation activities and for general corporate purposes.
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 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, organic growth initiatives and modernization activities are discussed below.

   West:

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

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

<u>*Texas:*</u>

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

<u>*North:*</u>

- *Garrison Energy Center* — We are actively permitting 618 MW of new combined-cycle capacity at a development site secured by a long-term lease with the City of Dover. For the first phase (309 MW), we have executed the Interconnection Services Agreement and the Interconnection Construction Services Agreement with PJM. For the second phase (309 MW), we have completed a feasibility study and are currently conducting a system impact study. Environmental permitting, site development planning and development engineering are underway and the first phase's capacity cleared PJM's 2015/2016 base residual auction. We received the air permit and executed a preliminary notice to proceed for the engineering, procurement and construction agreement during the first quarter of 2013. We expect COD for the first phase by the summer of 2015 and are currently evaluating funding sources including, but not limited to, nonrecourse financing, corporate financing or internally generated funds.

<u>*All Segments:*</u>

- *Turbine Modernization* — We continue to move forward with our turbine modernization program. Through December 31, 2012, we have completed the upgrade of eleven Siemens and eight GE turbines totaling over 200 MW and have committed to upgrade approximately three additional turbines.

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 or approved in 2012 is as follows:

   - We entered into a new twenty-year PPA with Western Farmers Electric Cooperative to provide 160 MW of power generated by our Oneta Energy Center, commencing in June 2014. The capacity under contract will increase in increments, up to a maximum of 280 MW in years 2019 through 2035.
   - We entered into a new five-year PPA with Southwestern Public Service Company, a subsidiary of Xcel Energy, to provide an additional 200 MW of power generated by our Oneta Energy Center commencing on June 1, 2014.
   - We entered into a new five-year resource adequacy contract with PG&E for approximately 280 MW of combined heat and power capacity from our Los Medanos Energy Center commencing in the summer 2013.
   - We entered into a new seven-year resource adequacy contract with Southern California Edison Company ("SCE") for approximately 280 MW of combined heat and power capacity from our Los Medanos Energy Center and a new five-year resource adequacy contract with SCE for approximately 120 MW of combined heat and power capacity from our Gilroy Cogeneration Plant, both commencing in January 2014.
   - We amended an existing PPA with Dow Chemical Company for an incremental energy sale of up to approximately 158,000 MWh per year of energy from our Los Medanos Energy Center which runs through February 2025.
   - We entered into a new fifteen-year PPA with American Electric Power Service Corporation, as agent for Public Service Company of Oklahoma, to provide 260 MW of energy, capacity and ancillary services from our Oneta Energy Center commencing in June 2016.
   - We entered into a new ten-year PPA with the Tennessee Valley Authority to provide the full output of power generated by our Decatur Energy Center, a natural gas-fired, combined-cycle power plant that can generate up to 795 MW, commencing in January 2013.

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 $364 billion in power sales in 2012 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 ISO-NE, NYISO and MISO markets. We produce several 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 capacity (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.

- Second, we provide capacity for sale to retail power providers. In various markets, retail power providers are required to demonstrate adequate resources to meet their power sales commitments. To meet this obligation, they procure a market product known as capacity 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. Because geothermal is a renewable source of energy, we receive a REC for each MWh we produce and are able to sell our RECs to load serving entities. New Jersey has a solar specific RPS which enables us to sell RECs from our Vineland Solar Energy Center.

- Fourth, our cogeneration power plants produce steam for sale to customers for use in industrial 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. As an 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 environmental allowances and credits, including those under RGGI, the federal Acid Rain and CAIR programs and emission reduction credits under the federal Nonattainment New Source Review program. We also participate in CO_2 emissions credit markets related to California's AB 32 GHG reduction program.

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

For sales of power from our natural gas-fired fleet into the short-term or spot markets, we attempt to maximize our operations when the market Spark Spread is positive. Assuming economic behavior by market participants, generating units generally are dispatched in order of their variable costs, with lower cost units being dispatched first and units with higher costs dispatched as demand, or "load," grows beyond the capacity of the lower cost units. For this reason, in a competitive market, the price of power typically is related to the variable operating costs of the marginal generator, which is the last unit to be dispatched in order to meet demand. The market factors that most significantly impact our operations are reserve margins, the price and supply of natural gas 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 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 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. Although uncertainty exists and there are key regional differences at a macro level, continued economic recovery and thus, corresponding load recovery, with the lack of broad new power plant investments in our key markets should lead to lower reserve margins and higher Market Heat Rates. Reserve margins by NERC regional assessment area for each of our segments are listed below:

	2012[(1)]
West:	
WECC	19.7%
Texas:	
TRE	13.5%
North:	
NPCC	21.5%
MISO	28.7%
PJM	30.6%
Southeast:	
SERC	32.2%
SPP	22.7%
FRCC	27.8%

(1) Data source is NERC weather-normalized estimates for 2012

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 do not expect fuel oil requirements to be material to our portfolio of power plant assets. Additionally, we have 4 MW of capacity from solar power generation technology with no fuel requirement.

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

Lower gas prices over the past four 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 $4.38/MMBtu, $4.03/MMBtu, and $2.83/MMBtu during 2010, 2011 and 2012, respectively. Natural gas prices in some parts of the country for parts of 2010, 2011 and 2012 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 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. Accordingly, there is an emerging view that lower priced natural gas will be available for the medium to long-term future.

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.

In 2012, 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.

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. 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 Pressures

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

- Environmental pressures continue to increase for coal-fired power generation as state and federal agencies enact rules to reduce air emissions of certain pollutants such as SO_2, NO_X, GHG, Hg and acid gases, restrict the use of once-through cooling, and provide for stricter standards for managing coal combustion residuals. Some of the regions in which we operate include older, less efficient fossil-fuel power plants that emit much higher amounts of GHG, SO_2, NO_X, Hg and acid gases, which we anticipate will be negatively impacted by current and future air emissions, water and waste regulations and legislation both at the state and federal levels. The estimated capacity for fossil-fueled plants which are 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	8,450 MW	132,258 MW
Texas:		
TRE	2,801 MW	82,552 MW
North:		
NPCC	6,445 MW	57,559 MW
MRO	4,489 MW	45,869 MW
RFC	25,034 MW	197,354 MW
Southeast:		
SERC	27,935 MW	235,483 MW
SPP	4,811 MW	59,961 MW
FRCC	1,233 MW	59,569 MW
Total	81,198 MW	870,605 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.
- 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 and transmission lines are becoming increasingly onerous.

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

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

- number of market participants, 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 2012, 30% of the power generated in the U.S. was fueled by natural gas and that approximately 56% of power generated in the U.S. was produced by coal and nuclear facilities, which generated approximately 37% and 19%, respectively. The EIA estimates that the remaining 14% of power generated in the U.S. was fueled by hydroelectric, fuel oil and other energy sources. We are subject to complex and stringent energy, environmental and other governmental laws and regulations at the federal, state and local levels in connection with the development, ownership and operation of our power plants. Federal and state legislative and regulatory actions continue to change. The federal government is 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 be retired. 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. In addition, the combination of emerging air emissions regulations, federal and state financial incentives and RPS requirements for renewables and their impact of expected increased investment in cleaner sources of generation will be somewhat counteracted by a lower natural gas price environment, which, should it persist, makes new investment in these types of power generation generally uneconomical. Thus, it is doubtful that generation from new nuclear power plants and renewable sources will be available in the quantities needed to meet future energy demand. Beyond economic issues, there are concerns over the reliability and adequacy of transmission infrastructure to transmit certain renewable generation from its source to where it is needed. Consequently, 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 and efficiency;

- accurately assess and effectively manage our risks; and
- benefit from future environmental regulation and legislation.

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 both power and natural gas, natural gas transportation, electric transmission, REC prices, carbon 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 116 billion KWh of electricity in 2012 across North America (primarily in the U.S.). We are one of the largest consumers of natural gas in North America having consumed approximately 867 Bcf during 2012. 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 2013 and beyond. When we elect to enter into these transactions, we are able to economically hedge a portion of our Spark Spread at pre-determined generation and price levels.

We conduct our hedging and optimization activities within a structured risk management framework based on controls, policies and procedures. We monitor these activities through active and ongoing management and oversight, defined roles and responsibilities, and daily risk measurement and reporting. Additionally, we seek to manage the associated risks through diversification, by controlling position sizes, by using portfolio position limits, and by entering into offsetting positions that lock in a margin. We also are exposed to commodity price movements (both profits and losses) in connection with these transactions. These positions are included in and subject to our consolidated risk management portfolio position limits and controls structure. 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 more volatility in our earnings. The fair value of our commodity derivative instruments residing in AOCI during the previous application of hedge accounting was reclassified to earnings during 2012 as the related economic transactions affected earnings or the forecasted transaction became probable of not occurring.

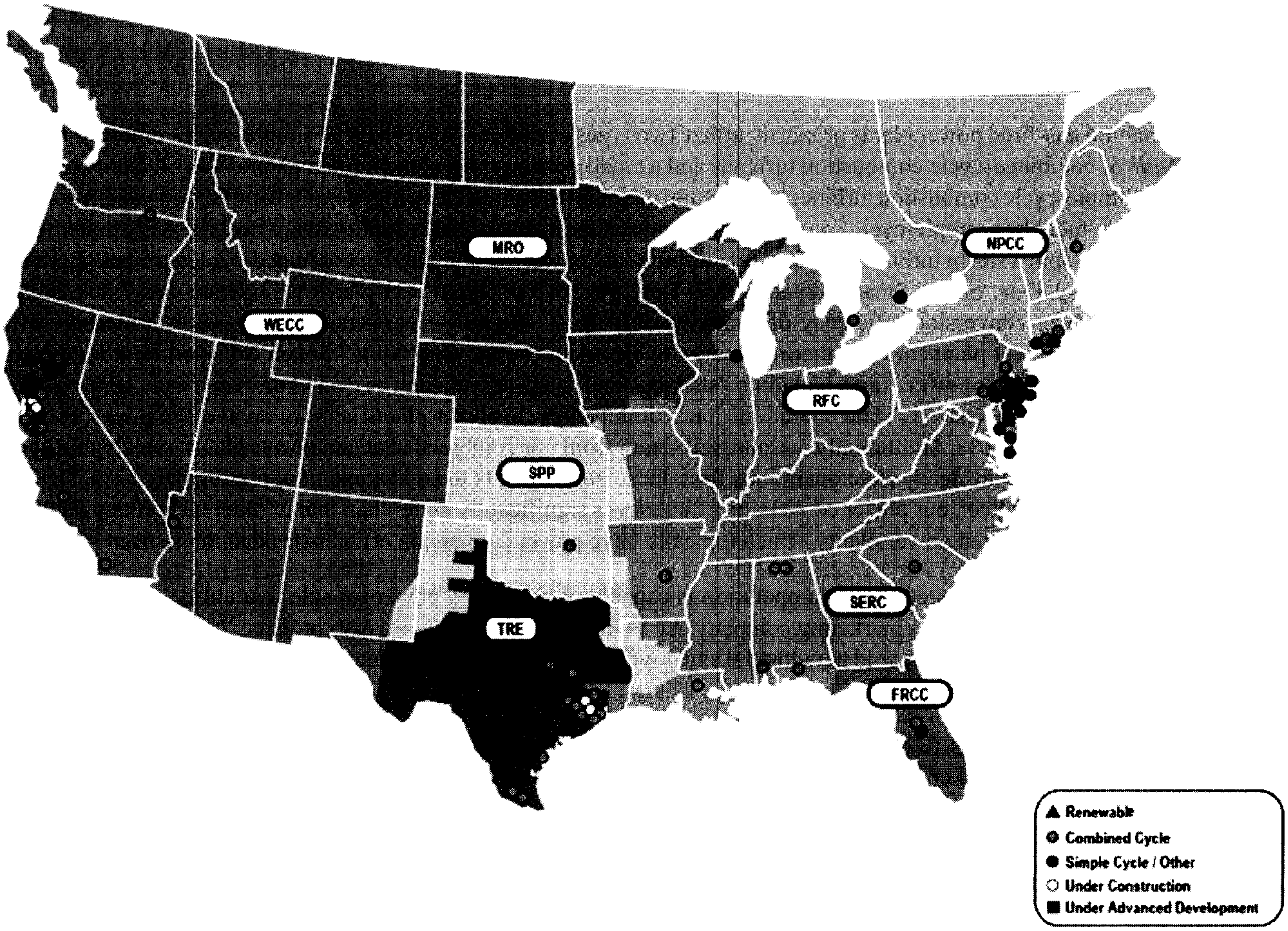
We have historically used interest rate swaps to adjust the mix between our fixed and variable rate debt. To the extent eligible, our interest rate swaps have been designated as cash flow hedges, and changes in fair value are recorded in OCI to the extent they are effective with gains and losses reclassified 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.

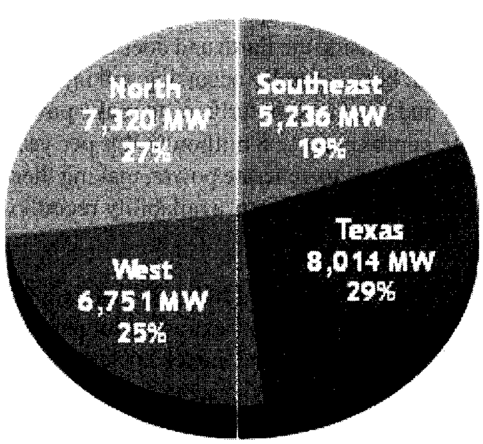
SEGMENT AND SIGNIFICANT CUSTOMER INFORMATION

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 one of our customers.

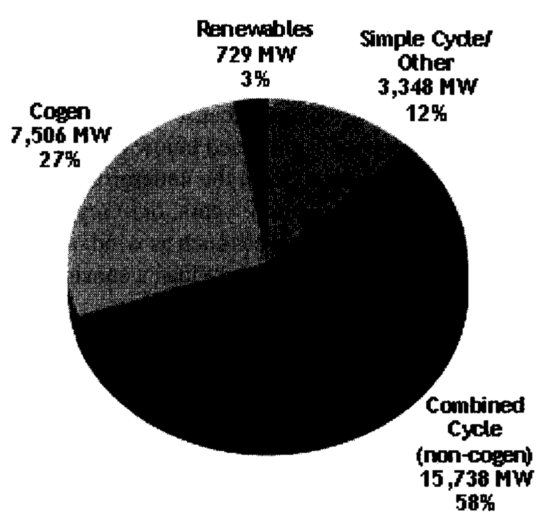
DESCRIPTION OF OUR POWER PLANTS



Geographic Diversity



Dispatch Technology



Power Plants in Operation at December 31, 2012

We own 92 power plants, including 4 under construction (1 new power plant and 3 expansions of existing power plants), with an aggregate generation capacity of approximately 27,321 MW and 1,163 MW under construction.

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 23,244 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. Our "all in" Steam Adjusted Heat Rate for 2012 for the power plants we operate was 7,361 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%.

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 natural gas fleet is relatively young with a weighted average age, based upon MW capacities in operation, of approximately thirteen years. Taken as a portfolio, our natural gas power plants are among the most efficient in converting natural gas to power and emit far fewer pollutants than most typical utility fleets. The age, scale, efficiency and cleanliness of our power plants is a unique profile in the 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 twelve consecutive years, our Geysers Assets have continued to generate approximately 6 million MWh per year. Unlike other renewable resources such as wind or sunlight, which depend on intermittent sources to generate power, making them less reliable, geothermal power provides a consistent source of energy as evidenced by our Geysers Assets' availability record of approximately 97% in 2012.

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, indicates 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 110 leases comprising approximately 29,019 acres of federal, state and private geothermal resource lands in The Geysers region of northern California. Our leases cover one contiguous area of property that comprises approximately 45 square miles in the northwest corner of Sonoma County and southeast corner of Lake County. The approximate breakout by volume of steam removed under the above leases for the year ended 2012 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 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 and Advanced Development

Set forth below is certain information regarding our operating power plants and projects under construction and advanced development at December 31, 2012.

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)	2012 Total MWh Generated(4)
WEST							
Geothermal							
McCabe #5 & #6	WECC	CA	Renewable	100%	78	78	690,435
Ridge Line #7 & #8	WECC	CA	Renewable	100%	69	69	627,748
Calistoga	WECC	CA	Renewable	100%	66	66	536,435
Eagle Rock	WECC	CA	Renewable	100%	66	66	601,883
Quicksilver	WECC	CA	Renewable	100%	53	53	393,048
Cobb Creek	WECC	CA	Renewable	100%	52	52	433,795
Lake View	WECC	CA	Renewable	100%	52	52	508,540
Sulphur Springs	WECC	CA	Renewable	100%	51	51	388,902
Socrates	WECC	CA	Renewable	100%	50	50	339,550
Big Geysers	WECC	CA	Renewable	100%	48	48	483,630
Grant	WECC	CA	Renewable	100%	43	43	346,996
Sonoma	WECC	CA	Renewable	100%	42	42	324,759
West Ford Flat	WECC	CA	Renewable	100%	24	24	221,400
Aidlin	WECC	CA	Renewable	100%	17	17	119,471
Bear Canyon	WECC	CA	Renewable	100%	14	14	98,335
Natural Gas-Fired							
Delta Energy Center	WECC	CA	Combined Cycle	100%	835	857	5,704,956
Pastoria Energy Center	WECC	CA	Combined Cycle	100%	770	749	4,371,891
Hermiston Power Project	WECC	OR	Combined Cycle	100%	566	635	2,888,861
Otay Mesa Energy Center	WECC	CA	Combined Cycle	100%	513	608	3,852,390
Metcalf Energy Center	WECC	CA	Combined Cycle	100%	564	605	2,778,933
Sutter Energy Center	WECC	CA	Combined Cycle	100%	542	578	1,273,920
Los Medanos Energy Center	WECC	CA	Cogen	100%	518	572	3,588,525
South Point Energy Center	WECC	AZ	Combined Cycle	100%	520	530	1,364,070
Gilroy Energy Center	WECC	CA	Simple Cycle	100%	—	141	67,181
Gilroy Cogeneration Plant	WECC	CA	Cogen	100%	109	130	241,850
King City Cogeneration Plant	WECC	CA	Cogen	100%	120	120	499,483
Greenleaf 1 Power Plant	WECC	CA	Combined Cycle	100%	50	50	60,273
Greenleaf 2 Power Plant	WECC	CA	Cogen	100%	49	49	279,760
Wolfskill Energy Center	WECC	CA	Simple Cycle	100%	—	48	16,549
Yuba City Energy Center	WECC	CA	Simple Cycle	100%	—	47	45,663
Feather River Energy Center	WECC	CA	Simple Cycle	100%	—	47	36,633
Creed Energy Center	WECC	CA	Simple Cycle	100%	—	47	10,130
Lambie Energy Center	WECC	CA	Simple Cycle	100%	—	47	9,371
Goose Haven Energy Center	WECC	CA	Simple Cycle	100%	—	47	9,801
Riverview Energy Center	WECC	CA	Simple Cycle	100%	—	47	19,048
King City Peaking Energy Center	WECC	CA	Simple Cycle	100%	—	44	11,772
Agnews Power Plant	WECC	CA	Combined Cycle	100%	28	28	143,775
Subtotal					5,909	6,751	33,389,762

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)	2012 Total MWh Generated(4)
TEXAS							
Deer Park Energy Center	TRE	TX	Cogen	100%	843	1,014	6,164,077
Baytown Energy Center	TRE	TX	Cogen	100%	782	842	4,510,187
Pasadena Power Plant(5)	TRE	TX	Cogen/ Combined Cycle	100%	763	781	4,638,034
Bosque Energy Center(6)	TRE	TX	Combined Cycle	100%	740	762	301,167
Freestone Energy Center	TRE	TX	Combined Cycle	75%	779	746	3,987,727
Magic Valley Generating Station	TRE	TX	Combined Cycle	100%	662	692	4,290,913
Channel Energy Center	TRE	TX	Cogen	100%	463	608	2,501,611
Brazos Valley Power Plant	TRE	TX	Combined Cycle	100%	520	606	3,384,971
Corpus Christi Energy Center	TRE	TX	Cogen	100%	426	500	2,287,273
Texas City Power Plant	TRE	TX	Cogen	100%	400	453	1,230,745
Clear Lake Power Plant	TRE	TX	Cogen	100%	344	400	515,663
Hidalgo Energy Center	TRE	TX	Combined Cycle	78.5%	392	374	2,133,709
Freeport Energy Center(7)	TRE	TX	Cogen	100%	210	236	1,436,720
Subtotal					7,324	8,014	37,382,797
NORTH							
Bethlehem Energy Center	RFC	PA	Combined Cycle	100%	1,037	1,130	5,811,693
Hay Road Energy Center	RFC	DE	Combined Cycle	100%	1,030	1,130	5,179,087
Edge Moor Energy Center	RFC	DE	Steam Cycle	100%	—	725	1,077,342
York Energy Center	RFC	PA	Combined Cycle	100%	519	565	3,484,727
Westbrook Energy Center	NPCC	ME	Combined Cycle	100%	552	552	2,446,074
Greenfield Energy Centre(8)	NPCC	ON	Combined Cycle	50%	422	519	1,645,699
RockGen Energy Center	MRO	WI	Simple Cycle	100%	—	503	260,064
Zion Energy Center	RFC	IL	Simple Cycle	100%	—	503	133,143
Mankato Power Plant	MRO	MN	Combined Cycle	100%	280	375	495,871
Cumberland Energy Center	RFC	NJ	Simple Cycle	100%	—	191	43,623
Deepwater Energy Center(9)	RFC	NJ	Steam Cycle	100%	—	158	96,860
Kennedy International Airport Power Plant	NPCC	NY	Cogen	100%	110	121	664,482
Sherman Avenue Energy Center	RFC	NJ	Simple Cycle	100%	—	92	30,757
Bethpage Energy Center 3	NPCC	NY	Combined Cycle	100%	60	80	204,385
Middle Energy Center(9)	RFC	NJ	Simple Cycle	100%	—	77	475
Carll's Corner Energy Center	RFC	NJ	Simple Cycle	100%	—	73	23,151
Cedar Energy Center(9)	RFC	NJ	Simple Cycle	100%	—	68	1,659
Mickleton Energy Center	RFC	NJ	Simple Cycle	100%	—	67	3,932
Missouri Avenue Energy Center(9)	RFC	NJ	Simple Cycle	100%	—	60	685
Bethpage Power Plant	NPCC	NY	Combined Cycle	100%	55	56	197,899
Christiana Energy Center	RFC	DE	Simple Cycle	100%	—	53	159
Bethpage Peaker	NPCC	NY	Simple Cycle	100%	—	48	106,552
Stony Brook Power Plant	NPCC	NY	Cogen	100%	45	47	309,901
Tasley Energy Center	RFC	VA	Simple Cycle	100%	—	33	164
Whitby Cogeneration(10)	NPCC	ON	Cogen	50%	25	25	205,417
Delaware City Energy Center	RFC	DE	Simple Cycle	100%	—	23	68
West Energy Center	RFC	DE	Simple Cycle	100%	—	20	42
Bayview Energy Center	RFC	VA	Simple Cycle	100%	—	12	1,772
Crisfield Energy Center	RFC	MD	Simple Cycle	100%	—	10	451
Vineland Solar Energy Center	RFC	NJ	Renewable	100%	—	4	8,960
Subtotal					4,135	7,320	22,435,094

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)]	2012 Total MWh Generated[(4)]
SOUTHEAST							
Oneta Energy Center	SPP	OK	Combined Cycle	100%	980	1,134	3,320,995
Morgan Energy Center	SERC	AL	Cogen	100%	720	807	4,062,128
Decatur Energy Center	SERC	AL	Combined Cycle	100%	782	795	3,176,398
Columbia Energy Center	SERC	SC	Cogen	100%	455	606	51,561
Osprey Energy Center	FRCC	FL	Combined Cycle	100%	537	599	3,127,895
Carville Energy Center	SERC	LA	Cogen	100%	449	501	2,855,396
Hog Bayou Energy Center	SERC	AL	Combined Cycle	100%	235	237	1,113,720
Santa Rosa Energy Center	SERC	FL	Combined Cycle	100%	235	225	850,178
Pine Bluff Energy Center	SERC	AR	Cogen	100%	184	215	1,489,526
Auburndale Peaking Energy Center	FRCC	FL	Simple Cycle	100%	—	117	27,080
Subtotal					4,577	5,236	20,074,877
Total operating power plants	**90**				**21,945**	**27,321**	**113,282,530**
Power plants sold during 2012							
Riverside Energy Center	MRO	WI	Combined Cycle	100%	n/a	n/a	1,148,198
Broad River Energy Center	SERC	SC	Simple Cycle	100%	n/a	n/a	1,073,303
Subtotal							2,221,501
Total operating and sold power plants							**115,504,031**
Projects Under Construction and Advanced Development							
Projects under construction							
Russell City Energy Center	WECC	CA	Combined Cycle	75%	429	464	n/a
Los Esteros Critical Energy Facility[(11)]	WECC	CA	Combined Cycle	100%	243	309	n/a
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
Projects under advanced development							
Garrison Energy Center	RFC	DE	Combined Cycle	100%	273	309	n/a
Total operating power plants and projects					**23,410**	**28,793**	

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

(6) Bosque Energy Center was acquired on November 7, 2012.

(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) 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.

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

(11) Los Esteros Critical Energy Facility is currently under construction to upgrade from a 188 MW simple-cycle generation power plant to a 309 MW combined-cycle generation power plant.

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 2011, our emissions of GHG amounted to about 41 million tons.

Natural Gas-Fired Generation

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

	Air Pollutant Emission Rates — Pounds of Pollutant Emitted Per MWh of Power Generated		
Air Pollutants	**Average U.S. Coal-, Oil-, and Natural Gas-Fired Power Plant[1]**	**Calpine Natural Gas-Fired, Combined-Cycle Power Plant[2]**	**Advantage Compared to Average U.S. Coal-, Oil-, and Natural Gas-Fired Power Plant**
Nitrogen Oxides, NO_x	1.92	0.14	92.7%
Acid rain, smog and fine particulate formation			
Sulfur Dioxide, SO_2	3.87	0.0058	99.9%
Acid rain and fine particulate formation			
Mercury Compounds[3]	0.00002	—	100%
Neurotoxin			
Carbon Dioxide, CO_2	1,825	876	52%
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 2011. Emission rates are based on 2011 emissions and net generation. The U.S. Department of Energy has not yet released 2012 information.

(2) Our natural gas-fired, combined-cycle power plant estimated emission rates are based on our 2011 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 2011. Emission rates are based on 2011 emissions and net generation from U.S. Department of Energy's Electric Power Annual Report for 2011.

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 eleven of our operating power plants and one power plant under construction 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.
- Our Russell City Energy Center will use 100% reclaimed water from the City of Hayward's Water Pollution Control Facility for cooling and boiler makeup, which will prevent nearly four million gallons of wastewater per day from being discharged into the San Francisco Bay.

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.

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

Criteria Pollutants and Hazardous Air Pollutants

The CAA requires the EPA to regulate emissions of pollutants considered harmful to public health and the environment. The EPA has set NAAQS for six "criteria" pollutants: carbon monoxide, lead, NO_2, particulate matter ("PM"), 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 National Emission Standards for Hazardous Air Pollutants 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. 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.

Prior to the April 16, 2012 filing deadline, a total of 30 petitions for review challenging MATS were filed in the U.S. Court of Appeals for the D.C. Circuit ("D.C. Circuit") and subsequently consolidated under the case *White Stallion Energy Center v. EPA*. On March 19, 2012, Calpine, along with other energy companies, filed a motion for leave to intervene in the consolidated case in support of the EPA. Petitioners are expected to argue that the rule is arbitrary and capricious because the EPA failed to adequately demonstrate its threshold finding that the rule is "appropriate and necessary"; the EPA failed to address their concerns that MATS could damage electricity grid reliability; and the standards for new sources are not achievable.

Several petitioners moved to sever the issues specific to the standards for new coal-fired power plants and expedite briefing on those issues. On June 28, 2012, the D.C. Circuit granted the motion to sever and expedite briefing, and the new unit case is being considered under a separate docket number. However, on July 20, 2012, the EPA granted partial administrative reconsideration of certain issues affecting new units, namely, measurement issues related to mercury and the data underlying particulate matter and hydrogen chloride emissions standards. The EPA stayed the effectiveness of MATS with respect to the new unit issues under reconsideration.

As a consequence, on September 12, 2012, the D.C. Circuit stayed the severed case addressing standards for new units and held that case in abeyance pending the EPA's administrative reconsideration of the new unit standards. In response to the petition for reconsideration, the EPA issued a proposed rule reconsidering MATS for new sources on November 30, 2012. The proposed rule would, among other things, amend certain new source standards and the requirements applicable during periods of startup and shut down. The public comment period on the proposed rule for new units closed on January 7, 2013. The EPA will issue a final reconsideration in March 2013.

The D.C. Circuit is being briefed on the remaining challenges to MATS that are not being held in abeyance (e.g., challenges to existing unit standards). Oral argument has not been scheduled for the remaining consolidated challenges to MATS.

Cross-State Air Pollution Rule

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR") which would require a total of 28 states, primarily in the eastern U.S., to reduce annual SO_2 emissions, annual NOx emissions and/or ozone season NOx emissions to assist in attaining three NAAQS: the 1997 annual PM2.5 NAAQS, the 1997 8-hour ozone NAAQS, and the 2006 24-hour PM2.5 NAAQS.

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

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

On August 21, 2012, the D.C. Circuit vacated CSAPR. The D.C. Circuit ordered the EPA to continue administering CAIR, which the EPA has been implementing since the D.C. Circuit stayed CSAPR in December 2011 and which CSAPR was designed to replace due to the flaws in CAIR identified by the D.C. Circuit in *North Carolina v. EPA*.

The EPA petitioned for *en banc* rehearing (i.e., by all active judges on the D.C. Circuit) on October 5, 2012. Intervenors supporting the EPA also submitted three petitions for *en banc* rehearing upon similar grounds, including one submitted by a coalition of environmental and public health organizations, one by a group of cities and states (including the states of North Carolina, Connecticut, Delaware, Illinois, Maryland, Massachusetts, New York, Rhode Island and Vermont) and one jointly filed by Calpine and Exelon Corporation. On January 24, 2013, the D.C. Circuit denied *en banc* rehearing in this case. A petition for a writ of certiorari to appeal this decision to the Supreme Court may still be filed by the EPA or any other party. Assuming the decision is not reversed by the U.S. Supreme Court upon a petition for writ of certiorari, the EPA must continue to implement CAIR while it creates a replacement for CSAPR.

CAIR and Multi-Pollutant Program

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, stating that the "EPA's approach – region-wide caps with no state specific quantitative contribution determinations or emission requirements – is fundamentally flawed." The court did not overturn the existing Cap-and-trade program for SO_2 reductions under the Acid Rain Program or the existing ozone season Cap-and-trade program under the NO_X State Implementation Plan Call. On September 25, 2008, the EPA petitioned the court for rehearing. On December 23, 2008, the court remanded CAIR without vacatur for the EPA to conduct further proceedings consistent with the July 11, 2008 opinion. As a result of the court's decision, CAIR was left intact and went into effect as planned on January 1, 2009, for many of our power plants located throughout the eastern and central U.S. Due to favorable allowance allocations, particularly in Texas, we have a net surplus of annual NO_X allowances and the net financial impact of the program to our operations is positive. As a result of CSAPR being vacated in August 2012, the D.C. Circuit reinstated CAIR until the EPA 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" for GHGs, which set GHG emission standards for cars and light trucks.

Under the EPA's longstanding interpretation of the CAA, the Tailpipe Rule automatically triggered regulation of stationary sources of GHG emissions under the Prevention of Significant Deterioration ("PSD") program (which requires state-issued construction permits for stationary sources that have the potential to emit over 100 or 250 tons per year ("tpy"), the applicable threshold depending on the type of source, of "any air pollutant") and Title V (which requires state-issued operating permits for stationary sources that have the potential to emit at least 100 tpy of "any air pollutant"). Accordingly, the EPA issued two rules phasing in stationary source GHG regulation. In the Timing Rule, the EPA delayed when major stationary sources of GHGs would otherwise be subject to PSD and Title V permitting, concluding that these requirements would commence on January 2, 2011, the date on which the Tailpipe Rule became effective. In the Tailoring Rule, the EPA departed from the CAA's 100/250 tpy emissions thresholds and provided that only the largest sources, those exceeding 75,000 or 100,000 tpy carbon dioxide equivalent ("CO_2e"), depending on the program and project, would initially be subject to GHG permitting.

Under Step 1 of the Tailoring Rule (beginning in January 2011), new or modified sources already required to obtain a PSD permit due to their emissions of conventional regulated pollutants must satisfy best available control technology ("BACT") requirements for GHGs if they emit or have the potential to emit at least 75,000 tpy CO_2e. Under Step 2 of the Tailoring Rule (beginning in July 2011), new sources that emit or have the potential to emit at least 100,000 tpy CO_2e and existing sources that emit at that level and that undertake modifications that increase emissions by at least 75,000 tpy CO_2e must obtain a PSD permit and satisfy BACT requirements for GHGs, regardless of their emissions of any conventional pollutants. Step 3 of the Tailoring Rule was finalized in July 2012 and maintained the GHG PSD and Title V permitting thresholds specified under Step 2.

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

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

On August 10, 2012, industry groups requested rehearing *en banc* of the D.C. Circuit's decision in *Coalition for Responsible Regulation*. On October 12, 2012, the EPA filed its response in opposition to the rehearing petition. The D.C. Circuit denied *en banc* review on December 20, 2012. The petitioners can still petition for a writ of certiorari to the U.S. Supreme Court, which must be done by March 20, 2013.

In light of the rehearing petition, on October 9, 2012, the D.C. Circuit decided to hold in abeyance a related case regarding Step 3 of the EPA's Tailoring Rule (*American Petroleum Institute v. EPA*). The parties were directed to file motions to govern future proceedings in *American Petroleum Institute* within 30 days of the D.C. Circuit's decision regarding *en banc* review in *Coalition for Responsible Regulation*. The case is still being held in abeyance and no motion has been filed seeking to release the case from abeyance.

In a related development, the EPA published a proposed New Source Performance Standard ("NSPS") for GHG emissions from new electric generating units on April 13, 2012. The proposed rule would establish an output-based CO_2 emissions standard of 1,000 lbs/MWh gross for new fossil fuel-fired generating units, which include boilers, integrated gasification combined-cycle units and stationary combined-cycle turbine units greater than 25 MW. The emissions standard is based on the performance of natural gas combined-cycle technology. The proposed NSPS would not apply to simple-cycle plants, plants that burn biomass, existing sources, sources being modified, or so-called "transitional sources" (i.e., coal-fired plants that received PSD permits by the publication date of the proposed rule (April 13, 2012) and commence construction within 12 months of the publication date of the proposal).

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

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

The EPA expects to finalize the proposed NSPS in March 2013.

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. On January 5, 2010, the EPA issued guidance on developing fee programs required under Section 185, but that guidance was vacated by the D.C. Circuit in 2011 due to the EPA's failure to follow notice-and-comment rulemaking procedures in its publication. On August 20, 2012, the EPA finalized approval of San Joaquin Valley Unified Air Pollution Control District's ("SJVUAPCD") fee-equivalent program, which the EPA determined is not less stringent than the program required by Section 185, and, therefore, is approvable as an equivalent alternative program. Environmentalists have challenged EPA's approval of this program in the U.S. Court of Appeals for the Ninth Circuit. The lawsuit is currently pending.

The TCEQ proposed a rule in November 2012 to create a Section 185 program, using an approach similar to that used in the approved SJVUAPCD program. We estimate that compliance with this fee could result in additional costs to us of up to $4 million on an annual basis and our financial statements include accruals for our estimated Section 185 fees. In addition to this annual fee, we have accrued our estimate for Section 185 fees that may be applied retroactively, although it is unclear whether the EPA intends to require such retroactive fees to be collected. Our estimates are dependent upon a number of factors that could change in the future dependent upon, among other things: the EPA approval of state rulemakings, the designation of nonattainment status, the outcome of pending and potential litigation challenging the EPA's approvals, the number of our operational power plants located in these areas and our emissions of NOx and VOC.

On June 18, 2012, the EPA determined that the New York-Northern New Jersey-Long Island ("NY-NJ-CT") one-hour ozone attainment area failed to achieve the one-hour NAAQS by the applicable deadline, but also that it is currently attaining the one-hour standard. As a result of this action, our facilities in New York and New Jersey will not incur Section 185 fees as of the date of that determination. The EPA has not taken a firm position on retroactive collection of Section185 fees.

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 are developing, or already have developed, state-specific or regional initiatives to reduce GHG emissions through mandatory programs. The most advanced programs include the RGGI in the northeast states and California's 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.

California: GHG — Cap-and-Trade Regulation

California's AB 32 requires the state to return to 1990 GHG emissions levels by 2020. To meet these levels, CARB has promulgated a number of regulations, including the Cap-and-trade regulation. In late 2011, CARB finalized its Cap-and-trade regulation and mandatory reporting regulation, which took effect on January 1, 2012. These regulations were further amended by 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 compliance instruments, which include allowances and offsets, in an amount equivalent to their emissions from sources of GHG located in California and from power imported into California. The first auction of GHG allowances was held on November 14, 2012 and included the sale of 2013 and 2015 vintage allowances. Quarterly auctions will be held every year from 2013 to 2020 with the next auction scheduled for February 19, 2013. The emissions market is currently functioning and the cost of the emissions permits is reflected in market pricing.

Currently, there are two pending lawsuits challenging the Cap-and-trade regulation. On March 28, 2012, two environmental organizations filed a lawsuit in San Francisco Superior Court seeking to invalidate the four protocols published by CARB for issuing offsets. On January 25, 2013, the court rejected the petitioners' claims, holding that CARB's development of the protocols was consistent with AB 32. The petitioners have until May 26, 2013 to appeal the decision in the California Court of Appeals. Additionally, on November 13, 2012, the California Chamber of Commerce filed a complaint in the Sacramento

Superior Court challenging CARB's authority to auction allowances. The Sacramento Superior Court is scheduled to hold a hearing on the merits in that case on May 31, 2013. We cannot predict the ultimate success of either of these lawsuits nor can we predict whether there will be any additional legal challenges filed against the regulation or what the associated impacts of any such litigation would be.

In September 2012, the CARB Board directed its staff, by mid-2013, to propose amendments to the Cap-and-trade regulation that would, among other things, increase the auction purchase limit for covered entities and provide allowances to covered entities that have long-term contracts that do not allow the costs of compliance to be passed through to their customers. On January 8, 2013, CARB published a notice for a 15-day rulemaking concerning linkage of California's and Quebec's Cap-and-trade programs ("Linkage Notice"). The Linkage Notice provides background for CARB's expected request that the California Governor make certain findings under Senate Bill ("SB") 1018, which are required before California links with any other jurisdiction's Cap-and-trade program. If the Governor makes these findings and CARB approves the proposed amendments, California and Quebec could hold their first joint auction of GHG allowances in August 2013. CARB's economic analysis estimates that linkage between California and Quebec has the potential to increase California's GHG allowance prices by 5% to 15%.

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

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.

RGGI caps regional CO_2 emissions and requires generators to acquire one allowance for every ton of CO_2 emitted over a three-year compliance period. Apart from state-specific set-asides and other factors, the vast majority of the region's CO_2 allowances are distributed to the market via quarterly public auctions. The most recent RGGI auction, conducted on December 5, 2012, cleared at the program's floor price of $1.93 per allowance.

We are required to purchase allowances by buying them in RGGI public auctions or via the secondary market, or by investment in qualified offsets, to cover CO_2 emissions from our power plants in the RGGI region. We have also received annual allocations from New York's long-term contract set-aside pool to cover some of the CO_2 emissions attributable to our PPAs at both the Kennedy International Airport Power Plant and Stony Brook Power Plant. We do not anticipate any significant business or financial impact from RGGI, given the efficiency of our power plants in RGGI states.

The original memorandum of understanding under which the states created RGGI envisioned a review of the program after the first compliance period, which ended in 2011. The intent of the review is to assess the need for modifications to the RGGI program design. The program review has incorporated input from the states, regulated industry, and other stakeholders, including environmental advocacy groups. Calpine is actively participating in the process. As a result of the program review, a model rule was issued on February 7, 2013, with a significantly lower regional emission cap. To enact this change, RGGI states must promulgate the model rule or something substantially similar at the state level. The RGGI states have indicated a desire to incorporate the model rule into state regulations by the end of 2013, with a new emission cap taking effect in 2014. 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 NO_x 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 our 158 MW Deepwater Energy Center, 68 MW Cedar Energy Center and 60 MW Missouri Avenue Energy Center will be physically unable to perform in the delivery year 2015 as a result of the HEDD Rule and that we plan to retire the units before the commencement of the PJM Reliability Pricing Model 2015/2016 delivery year. We received PJM's response in May 2012 in which PJM indicated its agreement with our deactivation request provided certain planned transmission upgrades are completed as scheduled. In the event the 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. Our 77 MW Middle Energy Center did not clear PJM's 2015/2016 base residual auction and we have provided notice to PJM of our intent to retire this unit before the commencement of the PJM Reliability Pricing Model 2015/2016 delivery year. 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 "firmed and shaped" transactions and unbundled RECs – claims to the renewable aspect of the power produced by a renewable resource that can be traded separately from the underlying power. In general, the ability to use "firmed and shaped" transactions and unbundled RECs becomes more limited over the course of the implementation period. On December 1, 2011, the CPUC issued a decision on intermediate RPS procurement targets between the present and 2020. On December 15, 2011, the CPUC issued a decision clarifying exactly what transactions will fall into which bucket. 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.

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

Clean Water Act and Water Intake Rule

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

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The EPA finalized the Phase I Rule in 2001, which applies to new facilities. The EPA initially promulgated the Phase II Rule, applying to large existing facilities, in 2004. However, the Phase II Rule was subsequently suspended and the EPA is required to finalize an updated rule applying to existing facilities by June 27, 2013. Calpine continues to participate in the rulemaking process; however, while the Section 316 (b) rule will likely affect our competitors, we do not expect these rules to have a material impact on our operations because only two peaking power plants we own employ once-through cooling systems, one of which (Deepwater Energy Center) is scheduled to retire in 2015.

Additionally, the EPA is bound by a consent decree to issue a final rule to establish revised effluent limitation guidelines for the steam electric point source category by January 31, 2014. This rule is unlikely to have a material impact on our operations.

In California, the EPA delegates the implementation of Section 316(b) to the California State Water Resources Control Board ("SWRCB"). SWRCB has promulgated its own once-through cooling policy that establishes a schedule for once-through cooling units to install 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 material 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 material 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.

On September 21, 2009, the U.S. Court of Appeals for the Second Circuit ("Second Circuit") issued a ruling in *State of Connecticut v. American Electric Power Company Inc.*, reversing a lower court's dismissal of two public nuisance claims filed by various states, municipalities and private entities against operators of coal-fired power plants. Plaintiffs argued that the power plant defendants contribute to global warming by emitting 650 million tons of CO_2 per year and these emissions are causing and will continue to cause serious harm affecting human health and natural resources. The lower court held that plaintiffs' claims presented a non-legal political question and dismissed the complaints. The Second Circuit vacated the lower court's decision, ruling in favor of the plaintiffs.

The Second Circuit's decision was appealed to the U.S. Supreme Court. On June 20, 2011, the Supreme Court issued a decision rejecting the plaintiffs' federal common law claim. The Court found that even if a federal common law claim could be made by plaintiffs, the CAA essentially "displaced" that claim. The case was remanded to the Second Circuit for further consideration of whether the plaintiffs may raise their claims under state common law or whether those claims are also preempted by federal law. The Second Circuit remanded to the district court for additional fact-finding. On December 6, 2011, the case was voluntarily dismissed. We cannot predict what impact the precedent of this case could have on our business.

The Supreme Court's decision in the above matter has had significant consequences for other climate change cases, including *Native Village of Kivalina v. ExxonMobil*. In *Kivalina*, a federal district court in California sided with the defendants (multiple oil, energy and utility companies) against the Village of Kivalina, a small, self-governing tribe of Inupiat people who reside north of the Arctic Circle. The residents of Kivalina had sued the defendants for damages under federal nuisance law arguing that, as a result of global warming to which the defendants allegedly contributed, Kivalina is subject to coastal storm waves and surges. On September 30, 2009, the court ruled in favor of the defendants, finding that the political question doctrine precluded the court from considering the plaintiff's federal public nuisance claim. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit affirmed, holding that the intervening U.S. Supreme Court case in *American Electric Power* militated against judicial review of Kivalina's claim because the CAA displaces federal common law addressing domestic GHG emissions. We cannot predict what impact the precedent of this case 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's policies and rules will continue to evolve, and FERC may amend or revise them, or may introduce new policies or rules in the future. The impact of such policies and rules on our business is uncertain and cannot be predicted at this time.

FERC Regulation of Market-Based Rates

Under the FPA and FERC's regulations, the wholesale sale of power at market-based or cost-based rates requires that the seller have authorization issued by FERC to sell power at wholesale pursuant to a FERC-accepted rate schedule. FERC grants market-based rate authorization based on several criteria, including a showing that the seller and its affiliates lack market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry and that there is no opportunity for abusive transactions involving regulated affiliates of the seller. All of our affiliates that own domestic power plants, except for certain of those power plants that are QFs under PURPA or that are located in ERCOT, as well as our market-based rate companies, are currently authorized by FERC to make wholesale sales of power at market-based rates.

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

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

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

FERC Regulation of Transfers of Jurisdictional Facilities

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

FERC Regulation of Qualifying Facilities

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

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

Station Power Ruling

On August 30, 2010, FERC issued an order reversing its prior rulings relating to a generator's self-supply of station power in the markets administered by CAISO. In the August 2010 order, the FERC concluded that it does not have jurisdiction to determine when a generator self-supplies station power and when the generator purchases its power needs through a retail sale. The FERC found that its jurisdiction covers only the transmission of station power and the states have exclusive jurisdiction to determine when the use of station power results in a retail sale. Calpine and several other generators filed an appeal of the FERC's decision. On December 18, 2012, the D.C. Circuit issued a decision in favor of the FERC. Although the decision concerns CAISO's treatment of station power, the decision is applicable to all ISOs and RTOs and could result in our power plants paying more for station power service in the future.

FERC Enforcement Authority

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

NERC Compliance Requirements

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

Regional and State Regulation of Power

The following summaries of the regional rules and regulations affecting our business focus on the West, Texas and North because these are the regions in which we have the most significant portfolios of power plants. While we provide a brief overview of the primary regional rules and regulations affecting our power plants located in other regions of the country, we do not provide an in-depth discussion of these rules and regulations because our asset portfolio in those regions is not as significant. All power plant and MW data is reported as of December 31, 2012.

West

We have 24 natural gas-fired power plants, including 2 under construction (1 new power plant and 1 expansion of an existing power plant), with the capacity to generate a total of 6,026 MW in the WECC NERC region, which extends from the Rocky Mountains westward. In addition, we own and operate 15 geothermal turbine-based power plants located in The Geysers region of northern California capable of producing a total of 725 MW. The majority of these power plants are located in California, in the CAISO region; however, we also own one power plant in both Arizona and 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. Pursuant to a FERC-approved tariff, CAISO has certain abilities to impose penalties on market participants for violations of its rules. CAISO maintains various markets for wholesale sales of power, differentiated by time and type of electrical service, into which our subsidiaries may sell power from time to time. These markets are subject to various controls, such as price caps and mitigation of bids when transmission constraints arise. The controls and the markets themselves are subject to regulatory change at any time. CAISO runs integrated day-ahead and real-time markets for energy and ancillary services. The energy markets include centralized, day-ahead and real-time markets for energy, a nodal transmission congestion management model that results in locational marginal pricing at each generation location, financial congestion hedging instruments, a centralized day-ahead commitment process and an energy bid cap of $1,000 per MWh. The locational marginal pricing market design is intended to reward and encourage generation resources on favorable grid locations, such as some of the locations of our power plants.

Prior to May 7, 2012, our Sutter power plant, which is a 578 MW natural gas-fired, combined-cycle power plant, had no contracts for its output in 2012. In late 2011, we determined that the power plant will be uneconomic and may have to be shut down absent incremental compensation. Consequently, on November 22, 2011, we submitted a request to the CAISO to compensate us for our Sutter power plant under a provision of CAISO's current tariff that is intended to avoid retirement of needed generating units. Under this tariff provision, the Capacity Procurement Mechanism ("CPM") allows the CAISO to compensate assets that are needed in the future, but are not currently receiving sufficient revenues to sustain operation. On March 29, 2012, the CPUC issued a resolution ordering California's three IOUs to negotiate to enter into contracts with us and on May 7, 2012, we announced that contracts were executed with California's three IOUs for the purchase of resource adequacy from our Sutter power plant for the period from July through December 2012.

The CPUC and CAISO continue to evaluate long-term capacity procurement policies and products for the California power market. With the expectation of significant increases in renewables, both agencies are evaluating the need for generation flexibility attributes such as dispatchability, ramping and load following. In addition, both agencies may consider forward procurement mechanisms or obligations. In this light, the CAISO filed a request at the FERC for a backstop mechanism on December 12, 2012, which, if approved by FERC, will allow the CAISO to look forward five years and compensate generation units that are needed for capacity or generation attributes, but would otherwise retire. This proposal is similar to that which was filed by the CAISO with the FERC early in 2012 in an attempt to retain our Sutter power plant. In January 2013, we protested the CAISO filing, raising concerns with the CAISO's approach and suggesting that a forward procurement obligation and central capacity clearing mechanism would be superior to the CAISO's proposal. The CPUC continues to review its resource adequacy and long-term procurement planning and may include forward procurement in the coming months.

A recently implemented CPUC settlement changes significant aspects of policy towards California QFs, including our non-renewable QF facilities. The settlement resolves issues related to QFs under existing QF contracts and establishes new energy pricing options for QFs under QF contracts, including the option to shed QF host and efficiency obligations and become dispatchable, and specifies mechanisms for the California IOUs to procure both existing combined heat and power ("CHP") that is not otherwise under contract and new CHP. Pursuant to the QF Settlement, we have converted two of our former QFs to dispatchable non-QF units, and we offered some of our resources into the IOUs' recent CHP solicitations. The IOUs selected our CHP offers for our Los Medanos Energy Center and Gilroy Cogeneration Plant and the transactions are now awaiting regulatory approval. The impact of the larger CHP settlement has been positive to Calpine.

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

Texas

We have 13 natural gas-fired power plants in the TRE NERC region with the capacity to generate a total of 8,014 MW, all of which are physically located in the ERCOT market. ERCOT is the ISO that manages approximately 85% of Texas' load and an electric grid covering about 75% of the state, overseeing transactions associated with Texas' competitive wholesale and retail power markets. FERC does not regulate wholesale sales of power in ERCOT. The PUCT exercises regulatory jurisdiction over the rates and services of any electric utility conducting business within Texas. Our subsidiaries that own power plants in Texas have power generation company status at the PUCT, and are either EWGs or QFs and are exempt from PUCT rate regulation. ERCOT ensures resource adequacy through an energy-only model rather than the capacity-based resource adequacy model that is more common among RTOs or ISOs in the Eastern Interconnect. In ERCOT, there is a market price cap for energy and capacity purchased by ERCOT. Under certain market conditions, the offer cap could be lower. Our subsidiaries are subject to the offer cap rules, but only for sales of power and capacity services to ERCOT.

The PUCT continues its very deliberative approach of considering design changes aimed at improving the ERCOT market's scarcity pricing signals. Of the two rulemakings undertaken in April 2012, the project dealing with near term system-wide offer cap ("SWOC") resulted in the offer cap being raised from $3,000/MWh to $4,500/MWh and took effect on August 1, 2012. In October 2012, the PUCT approved other changes including raising the SWOC beginning June 1, 2013 to $5,000/MWh, to $7,000/MWh on June 1, 2014 and finally to $9,000/MWh on June 1, 2015. In addition, the Peaker Net Margin ("PNM") will increase from $262,500 to $300,000 and in subsequent years it will be calculated at three-times the cost of new entry based on a simple-cycle natural gas turbine. If the PNM is exceeded in any given year, the SWOC is automatically lowered for the remainder of the year to the Low System Offer Cap ("LCAP"). The LCAP will change to the higher of $2,000/MWh, an increase from $500/MWh, or 50 times the daily Houston Ship Channel natural gas price index. Given the potential liquidity impacts of possibly higher offer caps, ERCOT stakeholders are considering the associated market credit and collateralization design changes in an effort to keep pace with the potential increase in the market's risk exposure. With these changes and proposed changes, we expect higher prices when scarcity pricing conditions occur which could have a positive impact on our Commodity Margin.

The Brattle Group's ("Brattle") June 1, 2012 release of its report on investment incentives and resource adequacy in the ERCOT market laid a solid foundation for continuing deliberation by the PUCT, ERCOT and market participants on two threshold issues. The first is whether the ERCOT region should have a mandated annual planning reserve margin or simply a reliability reserve margin target that is allowed to float in concert with the dynamics of the current energy-only market construct. The second threshold issue for the PUCT is to decide the best one of the five resource adequacy policy options offered by Brattle. At the request of the PUCT, Brattle prepared two separate resource adequacy proposals for its consideration: a modified energy-only proposal and the Texas Capacity Market, a centralized forward capacity market mechanism similar to PJM's. Calpine filed comments with the PUCT in support of the Texas Capacity Market concept. In addition, Brattle provided a demand response analysis that shows how much and how quickly price responsive demand can penetrate the ERCOT market. On October 25, 2012, the PUCT held a workshop to discuss the two Brattle proposals and received Brattle's demand response analysis. The PUCT has not voted on either proposal or established a timetable for further consideration of the proposals or whether to adopt a reserve margin requirement versus continuing with the current reserve margin target. A decision from the PUCT is expected in 2013. We continue to support the development of a centralized forward capacity market, which, depending on implementation, we view as superior to any energy-only mechanism, to ensure ERCOT meets its reliability objective under any market conditions. As these proceedings are ongoing, we cannot predict what the ultimate impact may be nor the impact on our financial condition, results of operations or cash flows.

The PUCT continues to consider other proposals to improve proper wholesale price formation. At the request of the PUCT, ERCOT has been working to develop a proposal for an operating reserves demand curve for PUCT and ERCOT stakeholder consideration. The key feature of the proposal is a pricing methodology based on the Value of Lost Load ("VOLL") and Loss of Load Probability ("LOLP"). The result of this calculation is a value that is dependent on the amount of available operating reserves, but added to the system-wide clearing price, without regard to whether the system is in scarcity conditions. It is possible some type of operating reserves demand curve proposal could be in place by summer 2013. We support the evaluation of this concept, but unlike a centralized forward capacity market, we do not view this concept as a solution for long-term resource adequacy in ERCOT. We cannot predict, at this time, all of the details of a prospective proposal or the ultimate impact on our financial condition, results of operations or cash flows.

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

ERCOT implemented a nodal market structure on December 1, 2010. A nodal market structure results in locational marginal pricing at each generation location rather than establishing pricing in four zones as was done prior to December 1, 2010. The implementation costs for the ERCOT central operating systems for nodal were paid by generating resources through a MWh-based surcharge. The Nodal Implementation Surcharge was levied at a rate of $0.375/MWh of all energy generated and was terminated in January 2013 with the retirement of the debt coverage of ERCOT's nodal costs.

The Sunset Review Process, implemented by the Texas Legislature in 1977, is the regular assessment of the need for a state agency to exist and to consider new and innovative changes to improve each agency's operations and activities. The Sunset Review Process works by setting a date on which an agency will be abolished unless legislation is passed to continue its functions. While significant changes were proposed by the Sunset Advisory Commission, the legislation did not become law. Therefore, the Sunset Advisory Commission has undertaken another review of these agencies and any resulting legislation will be considered in the 2013 legislative session. We cannot predict which changes, if any, will be placed into legislation and ultimately reach final passage. We will continue to participate in these processes where we anticipate any potential impact on our business.

North

We have a total of 30 power plants with 7,320 MW of peaking capacity located in the RFC, NPCC and MRO NERC regions.

We have 19 operating power plants with the capacity to generate a total of 4,491 MW in Eastern PJM. In addition, we have one operating power plant, with the capacity to generate 503 MW, located in Western PJM. Eastern PJM and Western PJM are both located in the RFC NERC region. PJM operates wholesale power markets, a locationally based capacity market, a forward capacity market and ancillary service markets. PJM also performs transmission planning for the region.

Certain states in the PJM market region, particularly New Jersey and Maryland, have taken actions that could impact the PJM capacity market. In New Jersey, legislation enacted in 2011 required the New Jersey Board of Public Utilities ("BPU") to issue a request for proposals ("RFP") for new generation. As a result of the RFP, the BPU directed New Jersey's four public utilities to enter into standard offer capacity agreements with the winning generators for new capacity to be built in New Jersey. Several entities have appealed the BPU's order directing the public utilities to enter into long-term contracts with those generators. The appeal process is continuing. Also, on February 9, 2011, we joined a group of generators and utilities in filing a complaint in federal district court challenging the constitutionality of the New Jersey legislation. On September 28, 2012, the judge in the proceeding denied all Motions for Summary Judgment. Discovery is continuing with a trial expected to be held in late March to early April 2013.

On September 29, 2011, the Maryland Public Service Commission ("MPSC") issued a "Notice of Approval of Request for Proposals for New Generation to be Issued by Maryland Electric Distribution Companies" (the "Notice"). The Notice required the state's IOUs to issue RFPs for up to 1,500 MW of capacity. The Notice specifies that proposals must be for new natural gas-fired capacity capable of delivery into the PJM Southwest Mid-Atlantic Area Council ("SWMAAC") delivery area. On April 12, 2012, the MPSC issued a further order in this proceeding directing certain Maryland IOUs located in the SWMAAC area to enter into a contract for differences with CPV Maryland, LLC ("CPV"), a generation developer that is currently developing a 661 MW natural gas-fired, combined-cycle generation plant in SWMAAC. The facility's scheduled COD is June 1, 2015. In May 2012, we filed with the Circuit Court of Baltimore County, Maryland a Petition for Review of the MPSC's order, asking the court to review the order and declare it invalid. Several other parties filed similar appeals. The appeals have been consolidated, but the case has been suspended pending resolution of certain terms in the contracts between the IOUs and CPV. In a separate action, several generators have filed a complaint in federal district court challenging the constitutionality of the MPSC's actions. That case is expected to go to trial in late February 2013.

At the FERC level, PJM has taken action to strengthen the Minimum Offer Price Rule ("MOPR") in its tariff. PJM's tariff changes are intended to address the negative implications from these state actions. The FERC issued an order in April 2011 approving amendments to PJM's MOPR tariff provisions. The FERC order is currently on appeal before the U.S. Court of Appeals for the Third Circuit. In December 2012, PJM filed further amendments to the MOPR that are intended to make the MOPR process more transparent and objective. On February 5, 2013, the FERC asked PJM to provide additional information about its proposal. While unclear, given the current timing of PJM's response and a subsequent FERC decision, it is still possible for the changes to be in effect for the 2016/2017 PJM Reliability Pricing Model base residual auction, to be held on May 13-17, 2013.

We have a total of eight natural gas-fired power plants with the capacity to generate a total of 1,448 MW in the NPCC NERC region. Five of these power plants are located in New York. NYISO manages the transmission system in New York and operates the state's wholesale power markets. NYISO manages both day-ahead and real-time energy markets using a locationally based marginal pricing mechanism that pays each generator the zonal marginally accepted bid price for the energy it produces.

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

We also have 50% ownership interests in two Canadian power plants, with the total capacity to generate 1,088 MW (544 MW net attributable to Calpine), located in the NPCC NERC region in Ontario, Canada. The Whitby cogeneration facility is a 50 MW facility located in Whitby, Ontario and the Greenfield Energy Centre is a 1,038 MW facility located in Courtright, Ontario. The Independent Electricity System Operator ("IESO") of Ontario operates the Province's wholesale power markets and directs the operation and ensures reliability of the IESO controlled grid. Hydro-One owns and operates the transmission system in Ontario, which is regulated by the Ontario Energy Board.

We have two natural gas-fired power plants with the capacity to generate a total of 878 MW operating within the MRO NERC region. MISO manages competitive locationally based wholesale day-ahead, real-time energy and ancillary services markets. MISO's Resource Adequacy model requires load serving entities to account for capacity obligations under Module E of the MISO tariff. MISO currently conducts a monthly voluntary capacity auction to help purchasers find suppliers with capacity to meet their incremental capacity needs. In 2013, MISO will complete a transition to a new capacity market design. Among other things, the new design will move MISO from a monthly capacity product to an annual capacity product, and implement annual auctions, although market participation will remain voluntary for all load-serving entities. We do not believe that this new market design will have a material impact on our business.

Southeast

We have one operating natural gas-fired power plant with the capacity to generate 1,134 MW located in the SPP NERC region. SPP is an RTO approved by FERC that provides independent administration of the electric power grid. SPP currently manages an energy-only location based real-time wholesale energy market. This market provides both nominal load-following and transmission constraint relief. In October 2012, the FERC approved tariff changes to enact SPP's proposed "Day 2" wholesale energy markets. SPP, which currently conducts a basic real-time nodal balancing market, will expand its market to a suite of new markets that will include centralized, security-constrained economic unit commitment with both a financially-binding, day-ahead nodal energy market and a physically-binding, real-time nodal energy market, a congestion management market using Transmission Congestion Rights, consolidate existing Balancing Areas and implement ancillary services markets for regulation and reserves. SPP will also have the authority to commit generation for reliability purposes and guarantee cost recovery for such units that are otherwise uneconomic. SPP will also have virtual load and generation markets that will permit hedging and speculation and plans to accommodate demand-side resource market participation. SPP did not propose any type of resource adequacy or capacity market in its new market design. We believe the market structure is generally beneficial to our Oneta Energy Center which is located in the SPP region.

We have nine natural gas-fired power plants with the capacity to generate a total of 4,102 MW operating within the SERC and the FRCC NERC regions. Opportunities to negotiate bilateral, individual contracts and long-term transactions with IOUs, municipalities and cooperatives exist within these regions. In addition to entering into bilateral transactions, there is a limited opportunity to sell into the short-term market.

In the Entergy sub-region, MISO has replaced SPP as the designated Independent Coordinator of Transmission. In this capacity, the Independent Coordinator of Transmission provides oversight of the Entergy transmission system. Entergy and MISO continue to move forward with their proposal to transfer functional control of Entergy's transmission system to MISO by December 2013. Entergy has received conditional approvals for change of control applications filed with the Arkansas Public Service Commission, the City of New Orleans, the Louisiana Public Service Commission, the Mississippi Public Service Commission, and the PUCT. We support Entergy membership in an RTO as soon as possible.

Other State Regulation of Power

State Public Utility Commissions, or PUC(s), have historically had broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in their states and to promulgate regulation for implementation of PURPA. Since all of our affiliates are either QFs or EWGs, none of our affiliates are currently subject to direct rate regulation by a state PUC. However, states may assert jurisdiction over the siting and construction of power generating facilities including QFs and EWGs and, with the exception of QFs, over the issuance of securities and the sale or other transfer of assets by these facilities. In California, for example, the CPUC was required by statute to adopt and enforce maintenance and operation standards for power plants "located in the state," including EWGs but excluding QFs, for the purpose of ensuring their reliable operation. As the owner and operator of power plants in California, our subsidiaries are subject to the power plant maintenance and operation standards and the general duty standards that are enforced by the CPUC.

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

Regulation of Transportation and Sale of Natural Gas

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

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.

Under the Natural Gas Act ("NGA"), the NGPA and the Outer Continental Shelf Lands Act, the FERC is authorized to regulate pipeline, storage and liquefied natural gas, or LNG, facility construction; the transportation of natural gas in interstate commerce; the abandonment of facilities; and the rates for services. The FERC is also authorized under the NGA to regulate the sale of natural gas at wholesale.

The FERC has civil penalty authority for violations of the 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). Thus, transactions executed on an ECM generally are not regulated directly by the CFTC. However, the CFTC may make special calls of market participants in the ECM and ECM transactions have come under the CFTC's scrutiny during investigations of fraud and manipulation in which the CFTC has broadly applied its statutory authority to punish persons who are alleged to have manipulated, or attempted to manipulate, the price of any commodity in interstate commerce or for future delivery. Moreover, while ECM transactions are not required to be cleared, if they are cleared, such cleared ECM transactions would be subject to regulation by the CFTC. We also expect the CFTC's powers and oversight to be increased by the Dodd-Frank Act. However, as discussed below, the extent of such increased powers and oversight, and its effect on ECM transactions, if any, is not yet certain.

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. A number of features in the legislation may impact our existing business. One of these is the requirement for central clearing of many OTC derivative transactions with clearing organizations. Moreover, whereas our OTC transactions have traditionally been negotiated on a bilateral basis, including the collateral arrangements thereunder, they now may be subject to the collateral and margining procedures of the clearing organization. Certain end-users may be able to benefit from an exception which would exempt them from mandatory clearing requirements. If the derivatives transactions which we enter into are determined to be subject to mandatory clearing requirements, we will seek to comply with the regulatory requirements in order to benefit from the end-user exception. Uncleared OTC derivatives transactions under the Dodd-Frank Act will also be subject to collateral and margining procedures established by CFTC regulation. These Title VII regulations have not, as of the date of this Report, been finalized. Other features of the Dodd-Frank Act which will have an impact on our derivative activities include trade reporting and trade execution. The effect of the Dodd-Frank Act on traditional dealers and market-makers as well as the consequential effect on market liquidity and, hence, pricing is uncertain. Nevertheless, we expect to be able to continue to participate in financial markets for our derivative transactions.

Some of the key regulatory rulemakings regarding the definition of specific entity designations and the swap definition rules for the Dodd-Frank Act were finalized in the second and third quarters of 2012. The CFTC also recently issued several no-action letters, interpretations and an exemptive order impacting the implementation schedule and interpretations of key provisions in the CFTC's Dodd-Frank Act implementation rules. We have reviewed our derivative activities over a one month survey period, as a proxy for future activity, and our intended future activities, and have determined that we are not a swap dealer as defined under the CFTC's final entity definition rule and, therefore, are not required to register as a swap dealer. We have established an internal working group for a thorough and ongoing evaluation of the impact and timing of these recent rulemakings on our operations as a non-swap dealer; however, it is difficult to fully assess the ultimate impact of the Dodd-Frank Act on us until all rulemakings are finalized and implemented.

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.

Other provisions

The Dodd-Frank Act also requires regulatory agencies, including the SEC, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act. In August 2012, as mandated by the Dodd-Frank Act, the SEC adopted final rules requiring resource extraction issuers to report, on an annual basis, any payments made by the issuer to the U.S. Federal Government or a foreign government for the purpose of the commercial development of oil, natural gas or minerals. The annual disclosure filing of these payments must be made with the SEC for fiscal years ending after September 30, 2013 (i.e. beginning with our fiscal year ending December 31, 2013). For calendar year end companies, like Calpine, the initial information reporting period runs from October 1, 2013 through December 31, 2013, and must be provided to the SEC by May 30, 2014. Our report will include information about the total amount of payments made to the U.S. Federal Government in conjunction with our geothermal leases from which we extract steam for our Geysers Assets.

The Dodd-Frank Act contains provisions to improve transparency and accountability concerning the supply of certain minerals, known as conflict minerals (namely tin, tantalum, tungsten or gold), originating from the conflict zones of the Democratic Republic of Congo ("DRC") and adjoining countries. In August 2012, as mandated by the Dodd-Frank Act, the SEC adopted final rules requiring all issuers that file reports with the SEC to report, on an annual basis, supply chain and sourcing information for companies that use conflict minerals mined from the DRC and adjoining countries in their products. These new requirements will require due diligence efforts in fiscal 2013, with initial disclosure requirements beginning in May 2014. Based on our preliminary analysis, we do not believe that any of our products contain conflict minerals; however, our assessment process to determine whether conflict minerals are necessary to the functionality or production of any of our products is not complete.

Geothermal Operations

The focus on induced seismicity caused by hydro-fracturing associated with natural gas and geothermal exploration and production could cause government entities or agencies to more stringently regulate that activity and such regulation could impact the exploration, development and operation of geothermal power plants, including our Geysers Assets.

EMPLOYEES

At December 31, 2012, we employed 2,151 full-time employees, of whom 158 were represented by collective bargaining agreements. We have 103 employees represented by collective bargaining agreements 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;
- quarterly and seasonal fluctuations;
- coal prices;
- 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, Regional Transmission Organizations 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. 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 more volatility in our earnings. The fair value of our commodity derivative instruments residing in AOCI during the previous application of hedge accounting was reclassified to earnings during 2012 as the related economic transactions affected earnings or the forecasted transaction became probable of not occurring. 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 uncontracted capacity is generally sold on the spot market at current market prices as merchant energy. When the terms of each of our various PPAs expire, it is possible that the price paid to us for the generation of power under subsequent arrangements or 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.

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 have accrued 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 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 158 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. It is possible we could incur interruptions from 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 could significantly disrupt our business operations.

Capital Resources; Liquidity

We have substantial liquidity needs and could face liquidity pressure.

As of December 31, 2012, our consolidated debt outstanding was $10.8 billion, of which approximately $7.8 billion was outstanding under our First Lien Notes and First Lien Term Loans. In addition we had $626 million issued in letters of credit and our pro rata share of unconsolidated subsidiary debt was approximately $224 million. Although we significantly extended our maturities during 2011 and 2010, we could face liquidity challenges as we continue to have substantial debt and substantial liquidity needs in the operation of our business. Our ability to make payments on our indebtedness, to meet margin requirements and to fund planned capital expenditures and development efforts will depend on our ability to generate cash in the future from our operations and our ability to access the capital markets. This, to a certain extent, is dependent upon industry conditions, as well as general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control, as discussed further in "— Commercial Operations" above. Although we are permitted to enter into new project financing credit facilities to fund our development and construction activities, there can be no assurance that we will not face liquidity pressure in the future. See additional discussion regarding our capital resources and liquidity in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

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

Our level of indebtedness has important consequences, including:

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

The soundness of financial institutions could adversely affect us.

We have exposure to many different financial institutions and counterparties including those under our First Lien Notes, 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 defaults under a financing agreement.

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

If our available cash, including future cash flows generated from operations, is not sufficient in the near term to finance our operations, post collateral or satisfy our obligations as they become due, we may need to access the capital and credit markets. Our ability to arrange financing (including any extension or refinancing) and the cost of the financing 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 Notes and our other debt instruments impose restrictions on us and any failure to comply with these restrictions could have a material adverse effect on our liquidity and our operations.

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

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

- engage in certain business activities; and
- enter into certain transactions with our affiliates.

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

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

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, 2012, we had $626 million issued in letters of credit under our Corporate Revolving Facility and other facilities, with $757 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, 2012, our subsidiaries had approximately \$1.0 billion in debt from our CCFC subsidiary and approximately \$1.8 billion in secured project financing from other subsidiaries, which are effectively senior to our First Lien Notes, 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 to impermissibly increase power plant construction in those states, could adversely impact our competitive position and business.

Certain states in the PJM market region, particularly New Jersey and Maryland, have taken actions that could impact the PJM capacity market. In New Jersey, legislation enacted in 2011 required the New Jersey Board of Public Utilities ("BPU") to issue a request for proposals ("RFP") for new generation. As a result of the RFP, the BPU directed New Jersey's four public utilities to enter into standard offer capacity agreements with the winning generators for new capacity to be built in New Jersey. Several entities have appealed the BPU's order directing the public utilities to enter into long-term contracts with those generators. The appeal process continues. Also, on February 9, 2011, we joined a group of generators and utilities in filing a complaint in federal district court challenging the constitutionality of the New Jersey legislation. On September 28, 2012, the judge in the proceeding denied all Motions for Summary Judgment. Discovery is continuing with a trial expected to be held in late March to early April 2013.

On September 29, 2011, the Maryland Public Service Commission ("MPSC") issued a "Notice of Approval of Request for Proposals for New Generation to be Issued by Maryland Electric Distribution Companies" (the "Notice"). The Notice required the state's IOUs to issue RFPs for up to 1,500 MW of capacity. The Notice specifies that proposals must be for new natural gas-fired capacity capable of delivery into the PJM Southwest Mid-Atlantic Area Council ("SWMAAC") delivery area. On April 12, 2012, the MPSC issued a further order in this proceeding directing certain Maryland IOUs located in the SWMAAC area to enter into a contract for differences with CPV Maryland, LLC ("CPV"), a generation developer that is currently developing a 661 MW natural gas-fired, combined-cycle generation plant in SWMAAC. The facility's scheduled COD is June 1, 2015. In May 2012, we filed with the Circuit Court of Baltimore County, Maryland a Petition for Review of the MPSC's order, asking the court to review the order and declare it invalid. Several other parties filed similar appeals. The appeals have been consolidated, but the case has been suspended pending resolution of certain terms in the contracts between the IOUs and CPV. In a separate action, several generators have filed a complaint in federal district court challenging the constitutionality of the MPSC's actions. That case is expected to go to trial in late February 2013.

At the FERC level, PJM has taken action to strengthen the Minimum Offer Price Rule ("MOPR") in its tariff. PJM's tariff changes are intended to address the negative implications from these state actions. The FERC issued an order in April 2011 approving amendments to PJM's MOPR tariff provisions. The FERC order is currently on appeal before the U.S. Court of Appeals for the Third Circuit. In December 2012, PJM filed further amendments to the MOPR that are intended to make the MOPR process more transparent and objective. On February 5, 2013, the FERC asked PJM to provide additional information about its proposal. While unclear, given the current timing of PJM's response and a subsequent FERC decision, it is still possible for the changes to be in effect for the 2016/2017 PJM Reliability Pricing Model base residual auction, to be held on May 13-17, 2013.

Unless these anticompetitive actions in New Jersey and Maryland are overturned by the courts or mitigated by the FERC, 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). Thus, transactions executed on an ECM generally are not regulated directly by the CFTC. However, the CFTC may make special calls of market participants in the ECM and ECM transactions have come under the CFTC's scrutiny during investigations of fraud and manipulation in which the CFTC has broadly applied its statutory authority to punish persons who are alleged to have manipulated, or attempted to manipulate, the price of any commodity in interstate commerce or for future delivery. Moreover, while ECM transactions are not required to be cleared, if they are cleared, such cleared ECM transaction would be subject to regulation by the CFTC. We also expect the CFTC's powers and oversight to be increased by the Dodd-Frank Act. However, as discussed below, the extent of such increased powers and oversight, and its effect on ECM transactions, if any, is not yet certain.

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

The Dodd-Frank Act 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. A number of features in the legislation may impact our existing business. One of these is the requirement for central clearing of many OTC derivative transactions with clearing organizations. Moreover, whereas our OTC transactions have traditionally been negotiated on a bilateral basis, including the collateral arrangements thereunder, they now may be subject to the collateral and margining procedures of the clearing organization. Certain end-users may be able to benefit from an exception which would exempt them from mandatory clearing requirements. If the derivatives transactions which we enter into are determined to be subject to mandatory clearing requirements, we will seek to comply with the regulatory requirements in order to benefit from the end-user exception. Uncleared OTC derivatives transactions under the Dodd-Frank Act will also be subject to collateral and margining procedures established by CFTC regulation. These Title VII regulations have not, as of the date of this Report, been finalized. Other features of the Dodd-Frank Act which will have an impact on our derivative activities include trade reporting and trade execution. The effect of the Dodd-Frank Act on traditional dealers and market-makers as well as the consequential effect on market liquidity and, hence, pricing is uncertain. Nevertheless, we expect to be able to continue to participate in financial markets for our derivative transactions.

Some of the key regulatory rulemakings regarding the definition of specific entity designations and the swap definition rules for the Dodd-Frank Act, which was signed into law on July 21, 2010, were finalized in the second and third quarters of 2012. The CFTC also recently issued several no-action letters, interpretations and an exemptive order impacting the implementation schedule and interpretations of key provisions in the CFTC's Dodd-Frank Act implementation rules. We have reviewed our derivative activities over a one month survey period, as a proxy for future activity, and our intended future activities, and have determined that we are not a swap dealer as defined under the CFTC's final entity definition rule and, therefore, are not required to register as a swap dealer. We have established an internal working group for a thorough and ongoing evaluation of the impact and timing of these recent rulemakings on our operations as a non-swap dealer; however, it is difficult to fully assess the ultimate impact of the Dodd-Frank Act on us until all rulemakings are finalized and implemented.

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.

The Dodd-Frank Act contains provisions to improve transparency and accountability concerning the supply of certain minerals, known as conflict minerals (namely tin, tantalum, tungsten or gold), originating from the conflict zones of the Democratic Republic of Congo ("DRC") and adjoining countries. In August 2012, as mandated by the Dodd-Frank Act, the SEC adopted final rules requiring all issuers that file reports with the SEC to report, on an annual basis, supply chain and sourcing information for companies that use conflict minerals mined from the DRC and adjoining countries in their products. These new requirements will require due diligence efforts in fiscal 2013, with initial disclosure requirements beginning in May 2014. Based on our preliminary analysis, we do not believe that any of our products contain conflict minerals; however, our assessment process to determine whether conflict minerals are necessary to the functionality or production of any of our products is not complete. Should we conclude that we are subject to the conflict minerals reporting requirements, we will have to determine the most efficient means of complying with the disclosure requirements, including diligence procedures to determine the sources of conflict minerals that are necessary to the functionality or production of our products and, if applicable, potential changes to products, processes or sources of supply as a consequence of such verification activities. It is also possible that we may face reputational harm if we determine that certain of our products contain minerals not determined to be "conflict free" and/or we are unable to alter our products, processes or sources of supply to avoid such materials.

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

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

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

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

In 2009, ten states in the northeast began the compliance period of a Cap-and-trade program, RGGI, to regulate CO_2 emissions from power plants. California 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 before the commencement of the PJM Reliability Pricing Model 2015/2016 delivery year. 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, 2012, 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 40% of our common stock at December 31, 2012, 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 three groups of these shareholders, which permits them to sell a large portion of their shares of common stock without being subject to the "trickle out" or other restrictions of Rule 144 under the Securities Act. 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, 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 2012 and 2011, as reported on the NYSE.

	High	Low
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
2011		
First Quarter	$ 16.25	$ 13.42
Second Quarter	17.10	15.00
Third Quarter	17.08	12.70
Fourth Quarter	16.68	12.79

As of December 31, 2012, there were 146 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," including "— Risks Relating to Our Common Stock" for a discussion of additional risks related to an investment in our common stock.

Repurchase of Equity Securities

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	2,999	$ 17.81	—	$ 173
November	3,933,533	$ 16.93	3,933,377	$ 106
December	5,009,857	$ 17.65	5,008,039	$ 18
Total	8,946,389	$ 17.33	8,941,416	$ 18

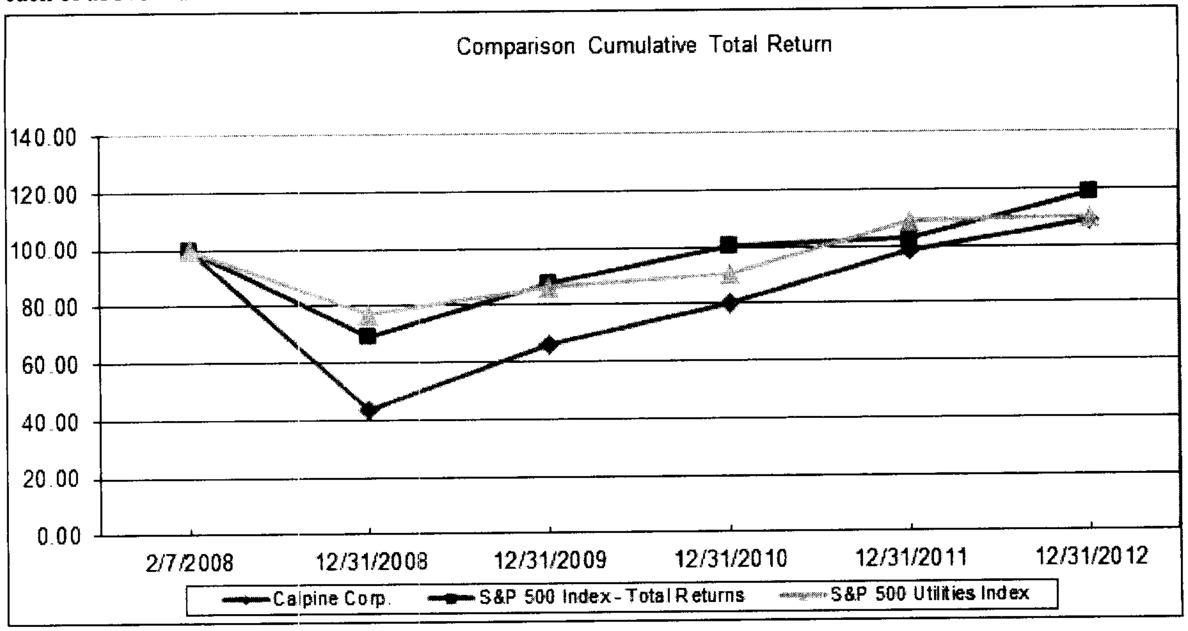
(1) Upon vesting of restricted stock awarded by us to employees, we withhold shares to cover employees' tax withholding obligations, other than for employees who have chosen to satisfy their tax withholding obligations in cash. During the fourth quarter of 2012, we withheld a total of 4,973 shares in the indicated months that are included in total number of shares purchased.

(2) On August 23, 2011, we announced that our Board of Directors had authorized the repurchase of up to $300 million in shares of our common stock. In April 2012, our Board of Directors authorized us to double the size of our share repurchase program, increasing our permitted cumulative repurchases to $600 million in shares of our common stock. As of the filing of this Report, we have completed our previously announced $600 million share repurchase program, having repurchased a total of 35,568,833 shares of our outstanding common stock at an average price paid of $16.87 per share. In February 2013, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock, bringing the cumulative authorization total to $1.0 billion. The shares repurchased under our share repurchase program were purchased in open market transactions and are held as treasury stock.

Stock Performance Graph

The performance graph below compares cumulative return on our common stock for the period February 7, 2008 through December 31, 2012, with the cumulative return of Standard & Poor's 500 Index (S&P 500) and the S&P 500 Utilities Index. Since the reorganized Calpine Corporation common stock began "regular way" trading on the NYSE on February 7, 2008, stock performance prior to February 7, 2008 does not provide meaningful comparison and has not been provided.

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



Company / Index	February 7, 2008	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011	December 31, 2012
Calpine Corporation....	$ 100	$ 43.86	$ 66.27	$ 80.36	$ 98.37	$ 109.21
S&P 500 Index...........	100	69.06	87.33	100.49	102.61	119.03
S&P Utilities Index.....	100	76.98	86.15	90.85	108.94	110.36

Item 6. *Selected Financial Data*

SELECTED CONSOLIDATED FINANCIAL DATA

	Years Ended December 31,				
	2012	2011	2010	2009	2008
	(in millions, except earnings (loss) per share)				
Statement of Operations data:					
Operating revenues	$ 5,478	$ 6,800	$ 6,545	$ 6,463	$ 9,837
Income (loss) before discontinued operations attributable to Calpine	$ 199	$ (190)	$ (162)	$ 114	$ (26)
Discontinued operations, net of tax expense, attributable to Calpine	—	—	193	35	36
Net income (loss) attributable to Calpine	$ 199	$ (190)	$ 31	$ 149	$ 10
Basic earnings (loss) per common share:					
Income (loss) before discontinued operations attributable to Calpine	$ 0.43	$ (0.39)	$ (0.33)	$ 0.24	$ (0.05)
Discontinued operations, net of tax expense, attributable to Calpine	—	—	0.39	0.07	0.07
Net income (loss) per common share attributable to Calpine	$ 0.43	$ (0.39)	$ 0.06	$ 0.31	$ 0.02
Diluted earnings (loss) per common share:					
Income (loss) before discontinued operations attributable to Calpine	$ 0.42	$ (0.39)	$ (0.33)	$ 0.24	$ (0.05)
Discontinued operations, net of tax expense, attributable to Calpine	—	—	0.39	0.07	0.07
Net income (loss) per common share attributable to Calpine	$ 0.42	$ (0.39)	$ 0.06	$ 0.31	$ 0.02
Balance Sheet data:					
Total assets	$ 16,549	$ 17,371	$ 17,256	$ 16,650	$ 20,738
Short-term debt and capital lease obligations	$ 115	$ 104	$ 152	$ 463	$ 716
Long-term debt and capital lease obligations	$ 10,635	$ 10,321	$ 10,104	$ 8,996	$ 9,756

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

Forward-Looking Information

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

INTRODUCTION AND OVERVIEW

Our Business

We are 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. 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 have invested in clean power generation to become a recognized leader in developing, constructing, owning and operating an environmentally responsible portfolio of power plants. We purchase natural gas and fuel oil as fuel for our power plants, engage in related natural gas transportation and storage transactions, and we purchase electric transmission rights to deliver power to our customers. We also enter into natural gas and power physical and financial contracts to hedge certain business risks and optimize our portfolio of power plants. Our goal is to be recognized as the premier wholesale power company in the U.S. as measured by our employees, customers, regulators, shareholders and communities in which our facilities are located. We seek to achieve sustainable growth through financially disciplined power plant development, construction, acquisition, operation and ownership. We will continue to pursue opportunities to improve our fleet performance and reduce operating costs. In order to manage our various physical assets and contractual obligations, we will continue to execute commodity agreements within the guidelines of our Risk Management Policy.

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 92 power plants, including 4 under construction (1 new power plant and 3 expansions of existing power plants), located throughout 20 states in the U.S. and in Canada, with an aggregate generation capacity of 27,321 MW and 1,163 MW under construction. Our fleet, including projects under construction, consists of 74 combustion turbine-based plants, 2 fossil steam-based plants, 15 geothermal turbine-based plants and 1 photovoltaic solar plant. Our segments have an aggregate generation capacity of 6,751 MW with an additional 773 MW under construction in the West, 8,014 MW with additional 390 MW under construction in Texas, 7,320 MW in the North and 5,236 MW in the Southeast. Our Geysers Assets are included in our West segment.

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 expansions or modernizations of existing power plants. Our notable operational performance metrics, significant projects under construction, organic growth initiatives and modernizations are discussed below:

- We produced approximately 116 billion KWh of electricity in 2012, 23% more than the same period in 2011 (includes generation from power plants owned but not operated by us and our share of generation from our unconsolidated power plants).
- Our entire fleet achieved a forced outage factor of 1.6% in 2012, our lowest on record and an improvement of 36% from 2011.
- Our entire fleet achieved an impressive starting reliability of 98.3% in 2012.
- During 2012, our outage services subsidiary completed 11 major inspections and 19 hot gas path inspections.
- For the past twelve consecutive years, our Geysers Assets have reliably generated approximately 6 million MWh per year and, in 2012, achieved an exceptional availability factor of approximately 97%.

- Construction of our Russell City Energy Center and modernization at our Los Esteros Critical Energy Facility continue to move forward with expected completion dates during the summer of 2013.
- We continue to make progress with our turbine modernization program and have ongoing development and expansion activities which include the advanced development of the Garrison Energy Center located in Dover, Delaware and the expansions of our Deer Park and Channel Energy Centers in Texas which are now under construction.

Enhancing Shareholder Value

We continue to make significant progress to deliver financially disciplined growth, to enhance shareholder value through our capital allocation and share repurchases and to set the foundation for continued 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, 2012 was marked by the following accomplishments:

- As of the filing of this Report, we have completed our previously announced $600 million share repurchase program, having repurchased a total of 35,568,833 shares of our outstanding common stock at an average price paid of $16.87 per share. In February 2013, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock, bringing the cumulative authorization total to $1.0 billion.
- During the first quarter of 2012, we terminated our legacy interest rate swaps formerly hedging our First Lien Credit Facility for a payment of approximately $156 million which eliminated our exposure from these instruments to further declines in interest rates.
- On October 9, 2012, we issued our 2019 First Lien Term Loan and used the proceeds to reduce our overall cost of debt and simplify our capital structure by redeeming a portion of our First Lien Notes and repaying project debt.
- On November 7, 2012, we completed the purchase of a modern, natural gas-fired, combined-cycle power plant with a nameplate capacity of 800 MW located in Bosque County, Texas for approximately $432 million which increased capacity in our Texas segment.
- 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 expect to use the sale proceeds for our capital allocation activities and for general corporate purposes.
- On December 31, 2012, we completed the sale of Riverside Energy Center, LLC to WP&L for approximately $402 million. We expect to use the sale proceeds for our capital allocation activities and for general corporate purposes.

For a further discussion of our capital management and significant financing transactions completed in 2012, 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 2012 is as follows:

- We entered into a new twenty-year PPA with Western Farmers Electric Cooperative to provide 160 MW of power generated by our Oneta Energy Center, commencing in June 2014. The capacity under contract will increase in increments, up to a maximum of 280 MW in years 2019 through 2035.
- We entered into a new five-year PPA with Southwestern Public Service Company, a subsidiary of Xcel Energy, to provide an additional 200 MW of power generated by our Oneta Energy Center commencing on June 1, 2014.
- We entered into a new five-year resource adequacy contract with PG&E for approximately 280 MW of combined heat and power capacity from our Los Medanos Energy Center commencing in the summer 2013.
- We entered into a new seven-year resource adequacy contract with Southern California Edison Company ("SCE") for approximately 280 MW of combined heat and power capacity from our Los Medanos Energy Center and a new five-year resource adequacy contract with SCE for approximately 120 MW of combined heat and power capacity from our Gilroy Cogeneration Plant, both commencing in January 2014.
- We amended an existing PPA with Dow Chemical Company for an incremental energy sale of up to approximately 158,000 MWh per year of energy from our Los Medanos Energy Center which runs through February 2025.
- We entered into a new fifteen-year PPA with American Electric Power Service Corporation, as agent for Public Service Company of Oklahoma, to provide 260 MW of energy, capacity and ancillary services from our Oneta Energy Center commencing in June 2016.

- We entered into a new ten-year PPA with the Tennessee Valley Authority to provide the full output of power generated by our Decatur Energy Center, a natural gas-fired, combined-cycle power plant that can generate up to 795 MW, commencing in January 2013.

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, 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, 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 each of the Broad River Entities, 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.

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2011 AND 2010

Below are our results of operations for the year ended December 31, 2011, as compared to the same period in 2010 (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.

	2011	2010	Change	% Change
Operating revenues:				
Commodity revenue	$ 6,753	$ 6,578	$ 175	3
Unrealized mark-to-market gain (loss)	35	(61)	96	#
Other revenue	12	28	(16)	(57)
Operating revenues	6,800	6,545	255	4
Operating expenses:				
Fuel and purchased energy expense:				
Commodity expense	4,299	4,187	(112)	(3)
Unrealized mark-to-market (gain) loss	60	(204)	(264)	#
Fuel and purchased energy expense	4,359	3,983	(376)	(9)
Plant operating expense	904	868	(36)	(4)
Depreciation and amortization expense	550	570	20	4
Sales, general and other administrative expense	131	151	20	13
Other operating expenses	77	91	14	15
Total operating expenses	6,021	5,663	(358)	(6)
Impairment losses	—	116	116	#
(Gain) on sale of assets, net	—	(119)	(119)	#
(Income) from unconsolidated investments in power plants	(21)	(16)	5	31
Income from operations	800	901	(101)	(11)
Interest expense	760	813	53	7
Loss on interest rate derivatives	145	223	78	35
Interest (income)	(9)	(11)	(2)	(18)
Debt extinguishment costs	94	91	(3)	(3)
Other (income) expense, net	21	15	(6)	(40)
Loss before income taxes and discontinued operations	(211)	(230)	19	8
Income tax benefit	(22)	(68)	(46)	(68)
Loss before discontinued operations	(189)	(162)	(27)	(17)
Discontinued operations, net of tax expense	—	193	(193)	#
Net income (loss)	(189)	31	(220)	#
Net income attributable to the noncontrolling interest	(1)	—	(1)	—
Net income (loss) attributable to Calpine	$ (190)	$ 31	$ (221)	#

	2011	2010	Change	% Change
Operating Performance Metrics:				
MWh generated (in thousands)[1]	90,875	88,323	2,552	3
Average availability	90.1%	90.4%	(0.3)%	—
Average total MW in operation[1]	27,234	24,993	2,241	9
Average capacity factor, excluding peakers	44.3%	46.0%	(1.7)%	(4)
Steam Adjusted Heat Rate	7,412	7,338	(74)	(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 $63 million for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily due to:

- the Conectiv Acquisition which closed on July 1, 2010, and our York Energy Center which achieved COD in March 2011; partially offset by
- the negative impact in Texas of unplanned outages at some of our power plants caused by an extreme cold weather event in early February 2011, which required us to purchase physical replacement power at prices substantially above our hedged price;
- lower Spark Spreads in our West segment resulting from a significant increase in hydroelectric generation in California in 2011 compared to 2010; and
- the expiration of certain hedge contracts which benefited the year ended December 31, 2010.

Our average total MW in operation increased by 2,241 MW, or 9%, primarily due to the Conectiv Acquisition which closed on July 1, 2010 and our York Energy Center which achieved COD in March 2011 partially offset by the sale of a 25% undivided interest in the assets of our Freestone power plant in December 2010. Generation increased 3% due primarily to higher generation in the North due to the Conectiv Acquisition and our York Energy Center and higher generation in Texas driven by extreme heat and drought conditions during the third quarter of 2011. The increase in generation was partially offset by lower generation in the West resulting from weaker price conditions which also largely contributed to a 4% decrease in our average capacity factor, excluding peakers in 2011 compared to 2010.

Unrealized mark-to-market gain/loss from hedging our future generation and fuel needs had an unfavorable variance of $168 million primarily driven by the realization of favorable hedge positions in 2011 reported in unrealized mark-to-market gain/loss at December 31, 2010, resulting in an unfavorable year-over-year change partially offset by unrealized gains on fuel and purchased energy positions reported at December 31, 2011.

Other revenue decreased for the year ended December 31, 2011, compared to the year ended December 31, 2010, due primarily to a decrease in other revenue of $15 million due to an adjustment related to prior periods on a major maintenance contract which resulted in higher revenue recognized in the second quarter of 2010.

Plant operating expense increased by $36 million for the year ended December 31, 2011, compared to the year ended December 31, 2010. Our normal, recurring plant operating expense decreased $32 million and costs related to unscheduled outages decreased $22 million, due largely to insurance recoveries for the year ended December 31, 2011, compared to the year ended December 31, 2010. The increase in plant operating expense was primarily due to an increase of $28 million related to our Mid-Atlantic assets acquired in the Conectiv Acquisition, an increase of $7 million related to our York Energy Center which achieved COD in March 2011, an increase of $41 million in major maintenance expense resulting from our plant outage schedule, an increase of $6 million in costs from scrap parts related to outages, an increase in costs of $5 million related to our voluntary departure incentive program which was initiated in the second quarter of 2011 and an increase of $3 million in stock-based compensation expense.

Depreciation and amortization expense decreased for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily resulting from a decrease of $39 million due to rotable parts being fully depreciated for some of our units, a decrease of $17 million related to a revision in the expected settlement dates of the asset retirement obligations of our power plants and a decrease of $5 million due to the sale of a 25% undivided interest in the assets of our Freestone power plant in December 2010. The decrease was partially offset by an increase of $24 million related to our Mid-Atlantic assets acquired in the Conectiv Acquisition, an increase of $6 million related to York Energy Center which achieved COD in March 2011 and an increase of $11 million related to depreciation for assets placed into service during 2011.

Sales, general and other administrative expense decreased for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily resulting from $26 million in Conectiv Acquisition-related costs incurred during the year ended December 31, 2010. The decrease was partially offset by $10 million due to the reversal of a bad debt allowance in the first quarter of 2010 as a result of Lyondell Chemical Co.'s emergence from Chapter 11 bankruptcy and the bankruptcy court's acceptance of our claim in the first quarter of 2010.

Other operating expenses decreased for the year ended December 31, 2011, compared to the year ended December 31, 2010, resulting from a decrease of $10 million in operating lease expense due to our purchase from a third party of the entity that held the lease of South Point in December 2010 and a decrease of $3 million in royalty expense due to lower revenues from our Geysers Assets resulting from lower prices in 2011 compared to 2010.

Impairment losses for the year ended December 31, 2010 consisted of an impairment of approximately $95 million related to South Point (see Note 3 of the Notes to Consolidated Financial Statements for further information related to our acquisition of the South Point lease and subsequent impairment of our South Point assets) and approximately $21 million associated with two development projects that originated prior to our Chapter 11 bankruptcy proceedings. During the third quarter of 2010, we learned the projects would not receive PPAs that would support their continued development and made the determination that continued development was unlikely.

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

Income from unconsolidated investments in power plants had a favorable variance for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily due to a $4 million year-over-year increase in operating income for Greenfield LP related to mechanical issues which impacted plant performance during the third quarter of 2010.

Interest expense decreased for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily due to a $45 million favorable change in unrealized mark-to-market activity related to the interest rate swaps hedging our variable rate debt that do not qualify for hedge accounting and a decrease of $7 million due to capitalized interest related to project debt for two of our facilities under construction. Also contributing to the favorable year-over-year change in interest expense was 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, which decreased to 7.6% for the year ended December 31, 2011, from 7.9% for the year ended December 31, 2010.

Loss on interest rate derivatives had a favorable change of $78 million for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily resulting from a year-over-year decrease of $115 million in historical unrealized losses previously deferred in AOCI and reclassified into income related to 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. The favorable change was partially offset by an unfavorable year-over-year change of approximately $20 million due to realized interest rate swap settlements and changes in fair value subsequent to the reclassification date of the interest rate swaps formerly hedging our First Lien Credit Facility term loans. Also contributing to the unfavorable year-over-year change was an increase of $17 million resulting from interest rate swap breakage costs related to the repayment of project debt in June 2011.

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. Debt extinguishment costs for the year ended December 31, 2010, consisted of $61 million associated with the retirement of term loans under the First Lien Credit Facility in May, July and October 2010 in connection with the issuance of the 2019, 2020 and 2021 First Lien Notes and $30 million associated with the acquisition of the Broad River lease which was accounted for as a refinancing of existing debt under U.S. GAAP. See Note 3 of the Notes to Consolidated Financial Statements for further information regarding our acquisition of the Broad River lease.

During the year ended December 31, 2011, we recorded an income tax benefit of $22 million compared to $68 million for the year ended December 31, 2010. The year-over-year change primarily resulted from an unfavorable variance in income tax expense of $128 million related to the application of intraperiod tax allocation and an increase in various state and foreign jurisdiction income taxes of $19 million for the year ended December 31, 2011, compared to the year ended December 31, 2010. The unfavorable variance in income tax expense was partially offset by a decrease in federal income tax of $101 million due primarily 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 for federal income tax reporting purposes and a decrease of $14 million due to the expiration of a statute of limitation related to an uncertain tax position. See Note 10 of the Notes to Consolidated Financial Statements for further discussion of the election to consolidate the CCFC group and the Calpine group for federal tax reporting purposes.

Income from discontinued operations for the year ended December 31, 2010, primarily consisted of $160 million associated with the gain, net of tax, on the sale of our 100% ownership interests in Blue Spruce and Rocky Mountain in December 2010. Also included in the income from discontinued operations for the year ended December 31, 2010, are the results of operations for Blue Spruce and Rocky Mountain. See Note 3 of the Notes to Consolidated Financial Statements for further discussion of our discontinued operations.

COMMODITY MARGIN AND ADJUSTED EBITDA

Management's Discussion and Analysis of Financial Condition and Results of Operations includes financial information prepared in accordance with U.S. GAAP, as well as the non-GAAP financial measures, Commodity Margin and Adjusted EBITDA, discussed below, which we use as 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, RGGI compliance and other environmental costs, 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, 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 consolidate 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 our hedging activities 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.

Commodity Margin by Segment for the Years Ended December 31, 2011 and 2010

The following tables show our Commodity Margin and related operating performance metrics by segment for the years ended December 31, 2011 and 2010. 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:	**2011**	**2010**	**Change**	**% Change**
Commodity Margin (in millions)	$ 1,061	$ 1,080	$ (19)	(2)
Commodity Margin per MWh generated	$ 44.54	$ 34.94	$ 9.60	27
MWh generated (in thousands)	23,823	30,909	(7,086)	(23)
Average availability	88.2%	91.5%	(3.3)%	(4)
Average total MW in operation	6,895	6,911	(16)	—
Average capacity factor, excluding peakers	43.6%	56.5%	(12.9)%	(23)
Steam Adjusted Heat Rate	7,418	7,316	(102)	(1)

West — Commodity Margin in our West segment for the year ended December 31, 2011 was comparable to the year ended December 31, 2010. During the year ended December 31, 2011, we experienced higher Commodity Margin contribution from hedges as well as the positive impact of origination activities in 2011 compared to 2010. These positive factors were offset by lower Spark Spreads resulting from a significant increase in hydroelectric generation in California in 2011 compared to 2010, and lower Commodity Margin resulting from an unscheduled outage at OMEC during the second quarter of 2011. Consistent with weaker price conditions, generation decreased 23% for the year ended December 31, 2011 compared to 2010. Average availability decreased by 4% due to an increase in the duration of outages during the second quarter of 2011 compared to the second quarter of 2010, as the weaker price environment provided an opportunity to extend the duration of scheduled maintenance outages due to limited opportunity costs. Our average total MW in operation decreased 16 MW primarily due to the retirement of our Pittsburg power plant in March 2010 as well as the expiration of our operating lease and subsequent retirement of our Watsonville (Monterey) cogeneration power plant in May 2010 which was partially offset by an increase related to the completion of turbine modernizations at two of our power plants in 2011.

Texas:	**2011**	**2010**	**Change**	**% Change**
Commodity Margin (in millions)	$ 469	$ 504	$ (35)	(7)
Commodity Margin per MWh generated	$ 14.41	$ 16.71	$ (2.30)	(14)
MWh generated (in thousands)	32,552	30,169	2,383	8
Average availability	89.0%	87.6%	1.4%	2
Average total MW in operation	6,988	7,166	(178)	(2)
Average capacity factor, excluding peakers	53.2%	48.1%	5.1%	11
Steam Adjusted Heat Rate	7,243	7,236	(7)	—

Texas — Commodity Margin in our Texas segment decreased by $35 million, or 7%, for the year ended December 31, 2011, compared to the year ended December 31, 2010. Despite an increase in Commodity Margin contributions from hedges, Commodity Margin was negatively impacted by unplanned outages at some of our power plants caused by an extreme cold weather event which occurred on February 2, 2011. Power prices increased dramatically as a result of the cold weather event and the plant outages, which required us to purchase physical replacement power at prices substantially above our hedged prices. Also contributing to the year-over-year decrease in Commodity Margin was the sale of a 25% undivided interest in the assets of our Freestone power plant in December 2010 which also drove a 178 MW, or 2%, decrease in our average total MW in operation which was partially offset by an increase related to the completion of turbine modernizations at several of our power plants in 2011 and 2010. The decrease in Commodity Margin was partially offset by significantly higher power prices driven by extreme heat and drought conditions which increased Spark Spreads during the third quarter of 2011 on our relatively small open position.

North:	2011	2010	Change	% Change
Commodity Margin (in millions)	$ 704	$ 535	$ 169	32
Commodity Margin per MWh generated	$ 45.37	$ 57.79	$ (12.42)	(21)
MWh generated (in thousands)	15,517	9,258	6,259	68
Average availability	91.6%	90.7%	0.9%	1
Average total MW in operation	7,268	4,833	2,435	50
Average capacity factor, excluding peakers	35.9%	32.8%	3.1%	9
Steam Adjusted Heat Rate	7,919	7,819	(100)	(1)

North — Commodity Margin in our North segment increased by $169 million, or 32%, primarily due to the Conectiv Acquisition which closed on July 1, 2010 and our York Energy Center which achieved COD in March 2011 which were both also the primary driver of the year-over-year increase in generation as well as the 2,435 MW increase in average total MW in operation during the year ended December 31, 2011 compared to the year ended December 31, 2010. The increase in Commodity Margin was partially offset by lower capacity prices in the second half of 2011 compared to the same period in 2010. Average capacity factor, excluding peakers, increased 9% primarily due to scheduled outages at two of our power plants in the fourth quarter of 2010.

Southeast:	2011	2010	Change	% Change
Commodity Margin (in millions)	$ 240	$ 272	$ (32)	(12)
Commodity Margin per MWh generated	$ 12.64	$ 15.12	$ (2.48)	(16)
MWh generated (in thousands)	18,983	17,987	996	6
Average availability	91.9%	92.5%	(0.6)%	(1)
Average total MW in operation	6,083	6,083	—	—
Average capacity factor, excluding peakers	40.6%	38.0%	2.6 %	7
Steam Adjusted Heat Rate	7,312	7,315	3	—

Southeast — Commodity Margin in our Southeast segment decreased by $32 million, or 12%, for the year ended December 31, 2011 compared to the year ended December 31, 2010 largely due to the expiration of certain hedge contracts which benefited the year ended December 31, 2010 as well as lower Commodity Margin that resulted from unscheduled outages that occurred during the second and third quarters of 2011.

Adjusted EBITDA

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

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

Additionally, we believe that investors commonly adjust EBITDA information to eliminate the effect of restructuring and other expenses, which vary widely from company to company and impair comparability. As we define it, Adjusted EBITDA represents EBITDA adjusted for the effects of impairment losses, gains or losses on sales, dispositions or retirements of assets, any unrealized gains or losses from accounting for derivatives, 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, Conectiv Acquisition-related costs and any extraordinary, unusual or non-recurring items plus the Adjusted EBITDA from our discontinued operations and adjustments to reflect the Adjusted EBITDA from our unconsolidated investments. We adjust for these items in our Adjusted EBITDA as our management believes that these items would distort their ability to efficiently view and assess our core operating trends.

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

The tables below provide a reconciliation of Adjusted EBITDA to our income (loss) from operations on a segment basis and to net income (loss) attributable to Calpine on a consolidated basis for years ended December 31, 2012, 2011 and 2010 (in millions).

	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][3]	—	—	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) loss on commodity derivative mark-to-market activity	(106)	123	3	5	—	25
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(2)(3)	—	—	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

	2010					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 31
Discontinued operations, net of tax expense						(193)
Income tax benefit						(68)
Debt extinguishment costs and other (income) expense, net						106
Loss on interest rate derivatives						223
Interest expense, net of interest income						802
Income from operations	$ 380	$ 237	$ 250	$ 27	$ 7	$ 901
Add:						
Adjustments to reconcile income from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	207	150	111	112	(7)	573
Impairment losses	97	—	—	19	—	116
Major maintenance expense	27	87	18	25	—	157
Operating lease expense	19	—	26	—	—	45
Unrealized (gain) on commodity derivative mark-to-market activity	(54)	(54)	(17)	(18)	—	(143)
(Gain) on sale of assets, net	—	(119)	—	—	—	(119)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(2)(3)	—	—	34	—	—	34
Stock-based compensation expense	11	8	2	3	—	24
Loss on dispositions of assets	—	9	—	1	—	10
Conectiv Acquisition-related costs(4)	—	—	36	—	—	36
Other	2	—	1	—	—	3
Adjusted EBITDA from continuing operations	689	318	461	169	—	1,637
Adjusted EBITDA from discontinued operations	75	—	—	—	—	75
Total Adjusted EBITDA	$ 764	$ 318	$ 461	$ 169	$ —	$ 1,712

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

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

(3) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include unrealized (gain) loss on mark-to-market activity of nil, $1 million and $1 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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

LIQUIDITY AND CAPITAL RESOURCES

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

Liquidity

At December 31, 2012, we had $1,284 million in cash and cash equivalents and $253 million of restricted cash. Amounts available for future borrowings were $757 million under our Corporate Revolving Facility. The following table provides a summary of our liquidity position at December 31, 2012 and 2011 (in millions):

	2012	2011
Cash and cash equivalents, corporate[1]	$ 1,153	$ 946
Cash and cash equivalents, non-corporate	131	306
Total cash and cash equivalents	1,284	1,252
Restricted cash	253	194
Revolving facility(ies) availability	757	560
Letter of credit availability[2]	—	7
Total current liquidity availability	$ 2,294	$ 2,013

(1) Includes $11 million and $34 million of margin deposits held by us posted by our counterparties at December 31, 2012 and 2011, respectively.

(2) Includes availability under our CDHI letter of credit facility. On January 10, 2012, we increased the CDHI letter of credit facility to $300 million and extended the maturity date to 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, 2012, we had $28 million of cash collateral posted in support of outstanding letters of credit under our CDHI letter of credit facility. We do not believe that this change will have a material impact on our liquidity.

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

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

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

Liquidity Sensitivity

Significant changes in commodity prices and Market Heat Rates can have an impact on our liquidity as we use margin deposits, cash prepayments and letters of credit as credit support (collateral) with and from our counterparties for commodity procurement and risk management activities. Utilizing our portfolio of transactions subject to collateral exposure, we estimate that as of January 18, 2013, an increase of $1/MMBtu in natural gas prices would result in an increase of collateral required by approximately $52 million. If natural gas prices decreased by $1/MMBtu, we estimate that our collateral requirements would increase by approximately $69 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 18, 2013, an increase of 500 Btu/KWh in the Market Heat Rate would result in an increase in collateral required by approximately $30 million. If Market Heat Rates were to fall at a similar rate, we estimate that our collateral required would decrease by $28 million. These amounts are not necessarily indicative of the actual amounts that could be required, which may be higher or lower than the amounts estimated above, and also exclude any correlation between the changes in natural gas prices and Market Heat Rates that may occur concurrently. These sensitivities will change as new contracts or hedging activities are executed.

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

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

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

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

Letter of Credit Facilities

The Corporate Revolving Facility represents our primary revolving facility. The table below represents amounts issued under our letter of credit facilities at December 31, 2012 and 2011 (in millions):

	2012	2011
Corporate Revolving Facility	$ 243	$ 440
CDHI	253	193
Various project financing facilities	130	130
Total	$ 626	$ 763

Capital Management and Significant Financing Transactions

In connection with our goals of enhancing long-term shareholder value and leveraging our three scale regions, we have completed, initiated or made progress toward completing the following key capital and financing transactions during 2012, as further described below.

2019 First Lien Term Loan

On October 9, 2012, we entered into and borrowed $835 million under our 2019 First Lien Term Loan, which bears 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 2019 First Lien Term Loan credit agreement), plus an applicable margin of 2.25%, or (ii) LIBOR plus 3.25% per annum subject to a LIBOR floor of 1.25%. We used the net proceeds received to redeem 10% of the aggregate principal amount of each series of our existing First Lien Notes at a redemption price of 103% of the principal amount redeemed and to repay project debt totaling $218 million, plus accrued and unpaid interest for each. The 2019 First Lien Term Loan allows us to reduce our overall cost of debt by replacing a portion of our First Lien Notes with fixed interest rates ranging from 7.25% to 8.0% with a corporate level term loan carrying a lower variable interest rate currently at 4.5% and to repay variable rate project debt. The 2019 First Lien Term Loan carries substantially the same terms as the First Lien Term Loans and matures on October 9, 2019. The 2019 First Lien Term Loan also contains substantially similar covenants, qualifications, exceptions and limitations as the First Lien Term Loans and First Lien Notes.

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.

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 expect to use the sale proceeds for our capital allocation activities and for general corporate purposes.

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 expect to use the sale proceeds for our capital allocation activities and for general corporate purposes.

CDHI

On January 10, 2012, we increased the CDHI letter of credit facility to $300 million and extended the maturity date to 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, 2012, we had $28 million of cash collateral posted in support of outstanding letters of credit under our CDHI letter of credit facility. We do not believe that this change will have a material impact on our liquidity.

Share Repurchase Program

On August 23, 2011, we announced that our Board of Directors had authorized the repurchase of up to $300 million in shares of our common stock. In April 2012, our Board of Directors authorized us to double the size of our share repurchase program, increasing our permitted cumulative repurchases to $600 million in shares of our common stock. As of the filing of this Report, we have completed our previously announced $600 million share repurchase program, having repurchased a total of 35,568,833 shares of our outstanding common stock at an average price paid of $16.87 per share. In February 2013, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock, bringing the cumulative authorization total to $1.0 billion.

Construction, Modernizations and Growth Initiatives

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

West:

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

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

Texas:

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

North:

Garrison Energy Center — We are actively permitting 618 MW of new combined-cycle capacity at a development site secured by a long-term lease with the City of Dover. For the first phase (309 MW), we have executed the Interconnection Services Agreement and the Interconnection Construction Services Agreement with PJM. For the second phase (309 MW), we have completed a feasibility study and are currently conducting a system impact study. Environmental permitting, site development planning and development engineering are underway and the first phase's capacity cleared PJM's 2015/2016 base residual auction. We received the air permit and executed a preliminary notice to proceed for the engineering, procurement and construction agreement during the first quarter of 2013. We expect COD for the first phase by the summer of 2015 and are currently evaluating funding sources including, but not limited to, nonrecourse financing, corporate financing or internally generated funds.

All Segments:

Turbine Modernization — We continue to move forward with our turbine modernization program. Through December 31, 2012, we have completed the upgrade of eleven Siemens and eight GE turbines totaling over 200 MW and have committed to upgrade approximately three additional turbines.

Major Maintenance and Capital Spending

Our major maintenance and capital spending remains an important part of our business. Our expected expenditures for 2013 are as follows (in millions):

		2013
Major maintenance expense	$	210
Capital expenditures, operations, net		160
Growth related capital expenditures		450
Total major maintenance expense and capital spending		820
Less: Amounts expected to be funded with financing[(1)]		(200)
Net major maintenance expense and capital spending	$	620

(1) Consist of amounts to be drawn under our Russell City Project Debt and Los Esteros Project Debt.

NOLs

We have significant NOLs that will provide future tax deductions when we generate sufficient taxable income during the applicable carryover periods. At December 31, 2012, our consolidated federal NOLs totaled approximately $7.3 billion. 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, 2012, 2011 and 2010 (in millions):

	2012	2011	2010
Beginning cash and cash equivalents	$ 1,252	$ 1,327	$ 989
Net cash provided by (used in):			
Operating activities	653	775	929
Investing activities	(470)	(836)	(831)
Financing activities	(151)	(14)	240
Net increase (decrease) in cash and cash equivalents	32	(75)	338
Ending cash and cash equivalents	$ 1,284	$ 1,252	$ 1,327

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.

Our decrease in cash provided by operating activities was partially offset by the following:

- *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.

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

- *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.

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

- *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.

2011 — 2010

Net Cash Provided By Operating Activities

Cash provided by operating activities for the year ended December 31, 2011, was $775 million compared to $929 million for the year ended December 31, 2010. The decrease in cash provided by operating activities was primarily due to:

- *Working capital* — Working capital employed increased by approximately $194 million for the year ended December 31, 2011 compared to 2010 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 reduction in margin requirements during the year ended December 31, 2010.
- *Interest paid* — Cash paid for interest, inclusive of interest rate swaps in hedging relationships, increased by $21 million to $656 million for the year ended December 31, 2011, as compared to $635 million for 2010. The increase was primarily due to timing of interest payments on our First Lien Notes and 2018 First Lien Term Loans as compared to the previously outstanding First Lien Credit Facility and project debt.
- *Prepayment premiums* — For the year ended December 31, 2011, we paid $13 million of prepayment premiums related to the extinguishment of the NDH Project Debt.

Our decrease in cash provided by operating activities was partially offset by the following:

- *Income from operations* — Income from operations, adjusted for non-cash items increased by $41 million for the year ended December 31, 2011, as compared to 2010. 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, 2011, were $836 million compared to cash flows used in investing activities of $831 million for the year ended December 31, 2010. The difference was primarily due to:

- *Purchase of Conectiv assets and BRSP* — We purchased the Conectiv assets and BRSP for approximately $1.7 billion in 2010. There were no acquisitions in 2011.
- *Capital expenditures* — Capital expenditures increased by $314 million primarily resulting from construction activity at the Russell City Energy Center, Los Esteros Critical Energy Facility and York Energy Center combined with our turbine modernization program.
- *Lower proceeds from sales of power plants, interests and other* — For the year ended December 31, 2011, we received proceeds of approximately $13 million from the disposal of other plant assets compared to proceeds of approximately $954 million primarily relating to the sale of Blue Spruce, Rocky Mountain and a 25% undivided interest in the assets of our Freestone power plant for the year ended December 31, 2010.
- *Settlement of non-hedging interest rate swaps* — During the year ended December 31, 2011 we made payments on interest rate swap derivative instruments associated with swaps that formerly hedged variable rate debt which was converted to fixed rate debt of $189 million compared to payments of $69 million during the same period in 2010.

- *Restricted cash* — The net decrease in restricted cash was $54 million for the year ended December 31, 2011, compared to $322 million for the same period in 2010. The decrease in restricted cash in 2011 as compared to 2010 was primarily due to the maturity of project debt and the corresponding reduction in restricted cash requirements.
- *Transmission credits* — During the year ended December 31, 2011, we paid $31 million for transmission credits related to construction of our Russell City Energy Center.

Net Cash Provided By (Used In) Financing Activities

Cash flows used in financing activities were $14 million for the year ended December 31, 2011, compared to cash flows provided by financing activities of $240 million for the year ended December 31, 2010. The change in cash flows provided by (used in) financing activities was primarily related to:

- *Issuance of the 2018 First Lien Term Loans* — During the year ended December 31, 2011, we received proceeds of approximately $1.7 billion from the issuance of the 2018 First Lien Term Loans. We used the proceeds to repay our NDH Project Debt of approximately $1.3 billion resulting in a net increase of $374 million.
- *Issuance of the First Lien Notes* — We received proceeds of approximately $1.2 billion from the issuance of the 2023 First Lien Notes and used those proceeds to terminate the First Lien Credit Facility in accordance with its repayment terms resulting in a net increase of $5 million during the year ended December 30, 2011, compared to a net increase of $14 million during the year ended December 31, 2010.
- *Reduced proceeds from project debt* — During the year ended December 31, 2011, we received proceeds of approximately $327 million related to our Russell City Project Debt and Los Esteros Project Debt. During 2010 we received proceeds of approximately $1.3 billion to fund the Conectiv Acquisition.
- *Lower repayments of project debt* — During the year ended December 31, 2011, we made repayments on project debt of approximately $550 million, compared to approximately $937 million for the year ended December 31, 2010.
- *Increased contributions from noncontrolling interest holder* — During the year ended December 31, 2011, we received proceeds of approximately $34 million from a noncontrolling interest holder in Russell City Energy Center, compared to contributions of approximately $17 million for the year ended December 31, 2010.
- *Decreased finance costs* — During the year ended December 31, 2011, primarily due to the refinancing of the First Lien Credit Facility and the NDH Project Debt, we incurred $81 million in finance costs primarily related to the issuance of the First Lien Notes and project debt, compared to $136 million in finance costs primarily related to the issuance of the First Lien Notes and project debt.
- *Stock repurchases* — During the year ended December 31, 2011, we made payments of approximately $119 million under the share repurchase program announced on August 23, 2011. There were no similar repurchases during the same period in 2010.

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 and financially settling timely 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 has also reduced the number of hedging counterparties willing to extend credit to us and reduced our ability to negotiate more favorable terms with them. However, we believe that we will continue to be able to work with our hedging counterparties to execute beneficial hedging transactions and provide adequate collateral. At December 31, 2012, 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, 2012, our equity method investees (Greenfield LP and Whitby) had aggregate debt outstanding of $448 million. Based on our pro rata share of each of the investments, our share of such debt would be approximately $224 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, 2012, are as follows (in millions):

	Amounts of Commitment Expiration per Period						
Guarantee Commitments	2013	2014	2015	2016	2017	Thereafter	Total Amounts Committed
Guarantee of subsidiary debt[1]	$ 47	$ 36	$ 37	$ 36	$ 26	$ 209	$ 391
Standby letters of credit[2][4]	536	41	—	—	19	30	626
Surety bonds[3][4][5]	—	—	—	—	—	4	4
Guarantee of subsidiary operating lease payments[4]	7	3	—	—	—	—	10
Total	$ 590	$ 80	$ 37	$ 36	$ 45	$ 243	$ 1,031

(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, 2012, $3 million of cash collateral is outstanding related to these bonds.

Contractual Obligations — Our contractual obligations as of December 31, 2012, are as follows (in millions):

	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Operating lease obligations[1]	$ 568	$ 57	$ 102	$ 98	$ 311
Purchase obligations:					
Turbine commitments	$ 28	$ 24	$ 4	$ —	$ —
Commodity purchase obligations[2]	3,003	486	668	504	1,345
LTSA	68	20	14	34	—
Cost to complete construction projects	241	228	13	—	—
Other purchase obligations[3]	1,554	148	309	247	850
Total purchase obligations[4]	$ 4,894	$ 906	$ 1,008	$ 785	$ 2,195
Debt[5]	$ 10,762	$ 97	$ 326	$ 2,759	$ 7,580
Other contractual obligations:					
Interest payments on debt[5][6]	$ 4,886	$ 683	$ 1,361	$ 1,252	$ 1,590
Liability for uncertain tax positions	60	—	28	—	32
Interest rate swap agreement[6]	206	41	85	57	23
Total other contractual obligations	$ 5,152	$ 724	$ 1,474	$ 1,309	$ 1,645

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

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

(5) A note payable totaling $33 million associated with the sale of the PG&E note receivable to a third party is excluded from debt for this purpose as it is a non-cash liability.

(6) Amounts are projected based upon interest rates at December 31, 2012.

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: GEC Holdings, LLC, Gilroy Energy Center, LLC, Creed, Goose Haven, Calpine Gilroy Cogen, L.P., Calpine Gilroy 1, Inc., Calpine King City Cogen, LLC, Calpine Securities Company, L.P. (a parent company of Calpine King City Cogen, LLC), Calpine King City, LLC (an indirect parent company of Calpine Securities Company, L.P.), Russell City Energy Company, LLC and OMEC. The financial information provided below represents the assets and liabilities for one of the special purpose subsidiaries as reflected on our Consolidated Balance Sheets and is provided below as required pursuant to certain applicable agreements. These amounts may differ materially from the assets and liabilities for these entities that present individual financial statements on a stand-alone basis to their project lenders.

GEC, a wholly-owned subsidiary of GEC Holdings, LLC, has been established as an entity with its existence separate from us and other subsidiaries of ours. On March 2, 2012, we closed on the purchase of two of the three third party interests in GEC Holdings, LLC pursuant to the purchase agreements that were executed in December 2011. The following table sets forth selected financial information of GEC at December 31, 2012 (in millions):

	2012
Assets	$ 456
Liabilities	$ 9

RISK MANAGEMENT AND COMMODITY ACCOUNTING

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

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

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

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

We have historically used interest rate swaps to adjust the mix between our fixed and variable rate debt. To the extent eligible, our interest rate swaps have been designated as cash flow hedges, and changes in fair value are recorded in OCI to the extent they are effective with gains and losses reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. 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.

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 decreased to approximately $0.4 billion at December 31, 2012, when compared to approximately $1.1 billion at December 31, 2011, and our derivative liabilities have decreased to approximately $0.6 billion at December 31, 2012, when compared to approximately $1.4 billion at December 31, 2011. At December 31, 2012, the fair value of our level 3 derivative assets and liabilities represent only a small portion of our total assets and liabilities measured at fair value (approximately 1%). See Note 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, 2012, through December 31, 2012, is summarized in the table below (in millions):

	Interest Rate Swaps	Commodity Instruments	Total
Fair value of contracts outstanding at January 1, 2012	$ (310)	$ 51	$ (259)
Items recognized or otherwise settled during the period[(1)(2)]	174	(72)	102
Fair value attributable to new contracts	—	(15)	(15)
Changes in fair value attributable to price movements	(58)	20	(38)
Changes in fair value attributable to nonperformance risk	(2)	(1)	(3)
Fair value of contracts outstanding at December 31, 2012[(3)]	$ (196)	$ (17)	$ (213)

(1) Interest rate settlements consist of recognized losses of $146 million related to interest rate swaps that were terminated during 2012, $15 million related to recognition of losses from settlements of designated cash flow hedges and $13 million in losses from settlements of undesignated interest rate swaps (represents a portion of interest expense and loss on interest rate derivatives as reported on our Consolidated Statements of Operations).

(2) Gains on settlement of commodity contracts not designated as hedging instruments of $144 million (represents a portion of Commodity revenue and Commodity expense as reported on our Consolidated Statements of Operations) and $72 million related to recognition of losses from other changes in derivative assets and liabilities not reflected in OCI or earnings, partially offset by de-designated cash flow hedges, previously reflected in AOCI.

(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, 2012, 2011 and 2010 (in millions):

	2012	2011	2010
Realized gain (loss)[(1)]			
Interest rate swaps	$ (157)	$ (193)	$ (31)
Commodity derivative instruments	387	143	114
Total realized gain (loss)	$ 230	$ (50)	$ 83
Unrealized gain (loss)[(2)]			
Interest rate swaps	$ 154	$ 55	$ (199)
Commodity derivative instruments	(82)	(25)	143
Total unrealized gain (loss)	$ 72	$ 30	$ (56)
Total mark-to-market activity, net	$ 302	$ (20)	$ 27

(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 de-designation of interest rate swap cash flow hedges and related reclassification from AOCI into earnings, hedge ineffectiveness and adjustments to reflect changes in credit default risk exposure.

	2012	2011	2010
Realized and unrealized gain (loss)			
Derivatives contracts included in operating revenues	$ 187	$ (20)	$ (19)
Derivatives contracts included in fuel and purchased energy expense	118	138	276
Interest rate swaps included in interest expense	11	7	(7)
Loss on interest rate derivatives	(14)	(145)	(223)
Total mark-to-market activity, net	$ 302	$ (20)	$ 27

Our change in AOCI from an accumulated loss of $178 million at December 31, 2011, to an accumulated loss of $248 million at December 31, 2012, was primarily driven by $56 million in losses on interest rate swaps due to a decrease in forward LIBOR rates, $3 million in losses related to capitalized realized losses on construction swaps hedging our Los Esteros Project Debt and Russell City Project Debt, $38 million in gains reclassified to earnings related to the settlement of de-designated commodity derivative cash flow hedges, and $1 million in unrealized actuarial losses recorded in 2012, partially offset by $16 million in losses on settlement of interest rate cash flow hedges reclassified to earnings, and a foreign currency translation gain of $3 million related to our Canadian subsidiaries and a $9 million income tax benefit recorded during the year ended December 31, 2012.

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, 2012, based on price source and the period during which the instruments will mature, are summarized in the table below (in millions):

Fair Value Source	2013	2014-2015	2016-2017	After 2017	Total
Prices actively quoted	$ (30)	$ (44)	$ —	$ —	$ (74)
Prices provided by other external sources	42	(1)	—	—	41
Prices based on models and other valuation methods	10	6	—	—	16
Total fair value	$ 22	$ (39)	$ —	$ —	$ (17)

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. The portfolio VAR calculation incorporates positions for the remaining portion of the current calendar year, exclusive of the current month of measurement, plus the following two calendar years. We measure VAR using a variance/covariance approach based on a confidence level of 95%, a one-day holding period and actual observed historical correlation. While we believe that our VAR assumptions and approximations are reasonable, different assumptions and/or approximations could produce materially different estimates.

The table below presents the high, low and average of our daily VAR for the years ended December 31, 2012 and 2011 (in millions):

	2012	2011
Year ended December 31:		
High	$ 77	$ 56
Low	$ 34	$ 20
Average	$ 49	$ 33
As of December 31	$ 63	$ 41

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

During the fourth quarter of 2012, we began to experience diminished liquidity in the forward commodity markets resulting from a decrease in participation of counterparties in the marketplace with which to transact our hedging activities. Although this occurrence of diminished liquidity did not negatively impact our 2012 financial results, should it persist during 2013 and beyond, it could decrease our ability to hedge our forward commodity price risk and create more volatility in our earnings.

Liquidity Risk — Liquidity risk arises from the general funding requirements needed to manage our activities and assets and liabilities. Increasing natural gas prices or Market Heat Rates can cause increased collateral requirements. Our liquidity management framework is intended to maximize liquidity access and minimize funding costs during times of rising prices. See further discussion regarding our uses of collateral as they relate to our commodity procurement and risk management activities in Note 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 portfolio of transactions adequately monitor our credit risk, and currently our counterparties are performing and financially settling timely according to their respective agreements. We monitor and manage our total comprehensive credit risk associated with all of our contracts and PPAs irrespective of whether they are accounted for as an executory contract, a normal purchase normal sale or whether they are marked-to-market and included in our derivative assets and liabilities on our Consolidated 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, 2012, 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, 2012)	2013	2014-2015	2016-2017	After 2017	Total
Investment grade	$ 21	$ (39)	$ —	$ —	$ (18)
Non-investment grade	—	—	—	—	—
No external ratings	1	—	—	—	1
Total fair value	$ 22	$ (39)	$ —	$ —	$ (17)

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, 2012. All outstanding balances and fair market values are shown gross of applicable premium or discount, if any (in millions):

	2013	2014	2015	2016	2017	Thereafter	Total	Fair Value December 31, 2012
Debt by Maturity Date:								
Fixed Rate	$ 25	$ 24	$ 9	$ 1,008	$ 1,087	$ 4,291	$ 6,444	$ 7,077
Average Interest Rate	9.2%	8.6%	5.4%	8.0%	7.2%	7.7%		
Variable Rate	$ 47	$ 130	$ 110	$ 114	$ 483	$ 3,082	$ 3,966	$ 3,949
Average Interest Rate(1)	3.6%	3.1%	3.4%	3.8%	4.9%	6.4%		

(1) Projection based upon anticipated LIBOR rates.

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 $(9) million at December 31, 2012.

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 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 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 our Bosque Energy Center and Conectiv Acquisitions, 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 more volatility in our earnings. Revenues and fuel costs derived from instruments that qualified for hedge accounting or represent an economic hedge are recorded in the same financial statement line item as the item being hedged. Although we have discontinued the application of hedge accounting treatment for our commodity derivative instruments, prior to this change and for our interest rate swaps, hedge accounting requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. We present the cash flows from our derivatives in the same category as the item being hedged (or economically hedged) within operating activities or investing activities (in the case of settlements for our interest rate swaps formerly hedging our First Lien Credit Facility term loans) on our Consolidated 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 and interest rate transactions that primarily act as economic hedges to our asset and interest rate portfolio, but either do not qualify as hedges under the hedge accounting guidelines or qualify under the hedge accounting guidelines and the hedge accounting designation has not been elected. Changes in fair value of commodity derivatives not designated as hedging instruments are recognized currently in earnings and are separately stated on our Consolidated Statements of Operations in unrealized mark-to-market gain/loss as a component of operating revenues (for power contracts and Heat Rate swaps and options) and fuel and purchased energy expense (for natural gas contracts, swaps and options). 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 and Other Project Debt — During 2010, we repaid approximately $3.5 billion of our First Lien Credit Facility term loans, which had approximately $3.3 billion notional amount of interest rate swaps hedging the scheduled variable interest payments, and in January 2011, we repaid the remaining approximately $1.2 billion of First Lien Credit Facility term loans which had approximately $1.0 billion notional amount of interest rate swaps hedging the scheduled variable interest payments. With the repayment of the remaining First Lien Credit Facility term loans, unrealized losses of approximately $91 million in AOCI related to the interest rate swaps formerly hedging the First Lien Credit Facility, were reclassified out of AOCI and into earnings as an additional loss on interest rate derivatives during 2011. In addition, we reclassified approximately $17 million in unrealized losses in AOCI to loss on interest rate derivatives during 2011 resulting from the repayment of project debt in 2011. During 2010, we reclassified approximately $206 million out of AOCI and into earnings as additional loss on interest rate derivatives related to interest rate swaps formerly hedging our First Lien Credit Facility term loans. We have presented 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 described above separate from interest expense as loss on interest rate derivatives on our Consolidated Statements of Operations. On March 26, 2012, we terminated the legacy interest rate swaps formerly hedging our First Lien Credit Facility and paid 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 and our interest rate swaps formerly hedging our First Lien Credit Facility term loans.

Accounting for VIEs and Financial Statement Consolidation Criteria

We consolidate all VIEs where we 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 on our Consolidated Balance Sheets. Our equity interest in the net income from Greenfield LP and Whitby for the years ended December 31, 2012, 2011 and 2010, 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 which achieved COD on May 3, 2010) from GE that may be exercised between years 2017 and 2024. GE holds a put option whereby they can require us to purchase the power plant, if certain plant performance criteria are met by 2025. We determined that we are not the primary beneficiary of the Inland Empire power plant, and we do not consolidate it due to the fact that GE directs the most significant activities of the power plant including operations and maintenance.

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. Estimates involved with salvage values include future estimated costs of dismantlement and repair, market prices, environmental regulations and technological advancements. Dependent upon our ability to accurately estimate salvage values and the timing of disposal, the salvage values actually realized for our assets could significantly increase or decrease resulting in additional gains or losses in the year of disposal.

We depreciate our assets under the straight-line method over the shorter of their estimated useful lives or lease term. 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 land or have a favorable option to purchase the land at conclusion of the lease term and approximately 0.15% of the depreciable costs basis for 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 PP&E 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. For the year ended December 31, 2010, the CCFC group was deconsolidated from the Calpine group for federal income tax reporting purposes. See Note 10 of the Notes to Consolidated Financial Statements for additional discussion of our Calpine and CCFC groups.

Our NOL carryforwards consist primarily of federal NOL carryforwards of approximately $7.3 billion, which expire between 2023 and 2031, and NOL carryforwards in 33 states and the District of Columbia totaling approximately $4.0 billion, which expire between 2013 and 2031, substantially all of which are offset with a full valuation allowance. We also have approximately $1.0 billion in foreign NOLs, 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. At December 31, 2012, approximately $2.4 billion of our $7.3 billion federal NOLs are not subject to annual Section 382 limitations. When considering our cumulative annual Section 382 limitations, in addition to our post-Effective Date NOLs that are not limited, our total unrestricted NOLs are approximately $7.1 billion. If a subsequent ownership change were to occur as a result of future transactions in our common 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 in 2012. 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 net operating tax 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 in 2012 due to NOL carryforwards, these "windfall" tax benefits are not reflected in our NOL in deferred tax assets for 2012. Windfalls included in NOL carryforwards, but not reflected in deferred tax assets as of December 31, 2012 were $10 million.

Under state income tax laws, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of the IRC. During 2011, we analyzed the effect of our change in ownership on the Effective Date for each of our significant states to determine the amount of our NOL limitation. The analysis determined that $640 million of our state NOLs are expected to expire unutilized as a result of statutory limitations on the use of some of our pre-emergence date NOLs as of the Effective Date or the cessation of business operations in various tax jurisdictions. We reduced our deferred tax asset for state NOLs that we are unable to utilize and made an equal reduction in our valuation allowance in 2011. The result did not have an impact on our income tax expense in 2011. We estimate that approximately $117 million of our state NOLs expired unutilized during 2012 as a result of statutory state limitations relating to the time period NOLs can be carried forward, and accordingly, we reduced our deferred tax asset and made an equal reduction in our valuation allowance. The reduction did not have an impact to our income tax expense in 2012. We will likely make future annual adjustments to our state NOLs that have expired or are limited under Section 382 of the IRC.

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, 2012, we had $92 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, 2012. In making its assessment of internal control over financial reporting, management used the criteria described in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on management's assessment, management has concluded that our internal control over financial reporting was effective as of December 31, 2012 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, 2012, 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 2012, 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.........	50	Chief Executive Officer
John B. Hill............	45	President and Chief Operating Officer
Zamir Rauf.............	53	Executive Vice President and Chief Financial Officer
W. Thaddeus Miller	62	Executive Vice President, Chief Legal Officer and Secretary
Jim D. Deidiker......	57	Senior Vice President and Chief Accounting Officer

Jack A. Fusco has served as our Chief Executive Officer and a member of our Board of Directors since August 10, 2008. He previously 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 under the captions "Board Meeting and Board Committee Information," "Corporate Governance Matters" and "Proposal 1 — Election of Directors" is incorporated herein by reference to our proxy statement for the 2013 annual meeting of stockholders to be held on May 10, 2013.

Item 11. ***Executive Compensation***

Information required by this Item is incorporated herein by reference to our proxy statement for the 2013 annual meeting of stockholders to be held May 10, 2013.

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 our proxy statement for the 2013 annual meeting of stockholders to be held May 10, 2013.

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

Information required by this Item is incorporated herein by reference to our proxy statement for the 2013 annual meeting of stockholders to be held May 10, 2013.

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

Information required by this Item is incorporated herein by reference to our proxy statement for the 2013 annual meeting of stockholders to be held May 10, 2013.

PART IV

Item 15. *Exhibits, Financial Statement Schedule*

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

Exhibit Number	Description
4.7	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).
4.8	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).
4.9	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 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 28, 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 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 28, 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 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 28, 2011).
4.12	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 28, 2011).
4.13	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 28, 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 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 28, 2011).

Exhibit Number	Description
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 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 28, 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 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 28, 2011).
4.17	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 28, 2011).
4.18	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 28, 2011).
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 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 5, 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 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 5, 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 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 5, 2012).
4.22	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 5, 2012).
4.23	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 5, 2012).

Exhibit Number	Description
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 October 21, 2009, providing for the issuance of 7.25% Senior Secured Notes due 2017. *
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 May 25, 2010, providing for the issuance of 8.0% Senior Secured Notes due 2019. *
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 July 23, 2010, providing for the issuance of 7.875% Senior Secured Notes due 2020. *
4.27	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. *
4.28	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. *
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 Securities and Exchange Commission on March 9, 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 28, 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 9, 2012).
10.2	Management Contracts or Compensatory Plans, Contracts or Arrangements.

Exhibit Number	Description
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 5, 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).†
10.2.4.1	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).†

Exhibit Number	Description
10.2.4.3	Non-Qualified Stock Option Agreement between the Company and W. Thaddeus Miller, dated August 11, 2010 (incorporated by reference to Exhibit 10.3 to Calpine's Current Report on Form 8-K filed with the SEC on August 17, 2010).†
10.2.4.4	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 29, 2010).†
10.2.7	Calpine Corporation 2009 Calpine Incentive Plan (incorporated by reference to Exhibit 10.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 8, 2009).†
10.2.7.1	The Amended and Restated Calpine Corporation 2008 Equity Incentive Plan (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on November 5, 2010).†
10.2.7.2	Form of Non-Qualified Stock Option Agreement (Pursuant to the 2008 Equity Incentive Plan) (incorporated by reference to Exhibit 10.4.3 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
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 Appendix A to Calpine's Definitive Proxy Statement on Schedule 14A filed with the SEC on April 5, 2010).†
10.2.9	Calpine Corporation Change in Control and Severance Benefits Plan (incorporated by reference to Exhibit 10.7 to Calpine's Current Report on Form 8-K filed with the SEC on December 26, 2012).†
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	Letter re Employment Offer, dated February 6, 2009, between the Company and Michael D. Rogers (incorporated by reference to Exhibit 10.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 7, 2009).†

Exhibit Number	Description
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, 2013

POWER OF ATTORNEY

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

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

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

Signature	Title	Date
/s/ JACK A. FUSCO Jack A. Fusco	Chief Executive Officer and Director (principal executive officer)	February 12, 2013
/s/ ZAMIR RAUF Zamir Rauf	Executive Vice President and Chief Financial Officer (principal financial officer)	February 12, 2013
/s/ JIM D. DEIDIKER Jim D. Deidiker	Chief Accounting Officer (principal accounting officer)	February 12, 2013
/s/ FRANK CASSIDY Frank Cassidy	Director	February 12, 2013
/s/ ROBERT C. HINCKLEY Robert C. Hinckley	Director	February 12, 2013
/s/ DAVID C. MERRITT David C. Merritt	Director	February 12, 2013
/s/ W. BENJAMIN MORELAND W. Benjamin Moreland	Director	February 12, 2013
/s/ ROBERT MOSBACHER, JR. Robert Mosbacher, Jr.	Director	February 12, 2013
/s/ DENISE M. O'LEARY Denise M. O'Leary	Director	February 12, 2013
/s/ WILLIAM E. OBERNDORF William E. Oberndorf	Director	February 12, 2013
/s/ J. STUART RYAN J. Stuart Ryan	Director	February 12, 2013

CALPINE CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2012

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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012 based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, 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, 2013

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2012, 2011 and 2010
(in millions, except share and per share amounts)

	2012	2011	2010
Operating revenues:			
Commodity revenue	$ 5,417	$ 6,753	$ 6,578
Unrealized mark-to-market gain (loss)	48	35	(61)
Other revenue	13	12	28
Operating revenues	5,478	6,800	6,545
Operating expenses:			
Fuel and purchased energy expense:			
Commodity expense	2,894	4,299	4,187
Unrealized mark-to-market (gain) loss	130	60	(204)
Fuel and purchased energy expense	3,024	4,359	3,983
Plant operating expense	922	904	868
Depreciation and amortization expense	562	550	570
Sales, general and other administrative expense	140	131	151
Other operating expenses	78	77	91
Total operating expenses	4,726	6,021	5,663
Impairment losses	—	—	116
(Gain) on sale of assets, net	(222)	—	(119)
(Income) from unconsolidated investments in power plants	(28)	(21)	(16)
Income from operations	1,002	800	901
Interest expense	736	760	813
Loss on interest rate derivatives	14	145	223
Interest (income)	(11)	(9)	(11)
Debt extinguishment costs	30	94	91
Other (income) expense, net	15	21	15
Income (loss) before income taxes and discontinued operations	218	(211)	(230)
Income tax expense (benefit)	19	(22)	(68)
Income (loss) before discontinued operations	199	(189)	(162)
Discontinued operations, net of tax expense	—	—	193
Net income (loss)	199	(189)	31
Net income attributable to the noncontrolling interest	—	(1)	—
Net income (loss) attributable to Calpine	$ 199	$ (190)	$ 31

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

CALPINE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS — (Continued)
(in thousands, except per share amounts)

	2012	2011	2010
Basic earnings (loss) per common share attributable to Calpine:			
Weighted average shares of common stock outstanding (in thousands)	467,752	485,381	486,044
Income (loss) before discontinued operations attributable to Calpine	$ 0.43	$ (0.39)	$ (0.33)
Discontinued operations, net of tax expense attributable to Calpine	—	—	0.39
Net income (loss) per common share attributable to Calpine — basic	$ 0.43	$ (0.39)	$ 0.06
Diluted earnings (loss) per common share attributable to Calpine:			
Weighted average shares of common stock outstanding (in thousands)	471,343	485,381	487,294
Income (loss) before discontinued operations attributable to Calpine	$ 0.42	$ (0.39)	$ (0.33)
Discontinued operations, net of tax expense attributable to Calpine	—	—	0.39
Net income (loss) per common share attributable to Calpine — diluted	$ 0.42	$ (0.39)	$ 0.06

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, 2012, 2011 and 2010
(in millions)

	2012	2011	2010
Net income (loss)	$ 199	$ (189)	$ 31
Cash flow hedging activities:			
Gain (loss) on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income (loss)	(61)	(69)	25
Reclassification adjustment for (gain) loss on cash flow hedges realized in net income (loss)	(20)	(25)	141
Unrealized actuarial losses arising during period	(1)	(3)	—
Foreign currency translation gain (loss)	3	(1)	2
Income tax (expense) benefit	9	45	(27)
Other comprehensive income (loss)	(70)	(53)	141
Comprehensive income (loss)	129	(242)	172
Comprehensive income attributable to the noncontrolling interest	—	(1)	—
Comprehensive income (loss) attributable to Calpine	$ 129	$ (243)	$ 172

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
December 31, 2012 and 2011
(in millions, except share and per share amounts)

	2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents ($109 and $285 attributable to VIEs)	$ 1,284	$ 1,252
Accounts receivable, net of allowance of $6 and $13	437	598
Margin deposits and other prepaid expense	244	193
Restricted cash, current ($53 and $57 attributable to VIEs)	193	139
Derivative assets, current	339	1,051
Inventory and other current assets	335	329
Total current assets	2,832	3,562
Property, plant and equipment, net ($4,192 and $4,313 attributable to VIEs)	13,005	13,019
Restricted cash, net of current portion ($59 and $53 attributable to VIEs)	60	55
Investments	81	80
Long-term derivative assets	98	113
Other assets	473	542
Total assets	$ 16,549	$ 17,371
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 382	$ 435
Accrued interest payable	180	200
Debt, current portion ($39 and $41 attributable to VIEs)	115	104
Derivative liabilities, current	357	1,144
Income taxes payable	11	3
Other current liabilities	273	276
Total current liabilities	1,318	2,162
Debt, net of current portion ($2,660 and $2,522 attributable to VIEs)	10,635	10,321
Long-term derivative liabilities	293	279
Other long-term liabilities	247	245
Total liabilities	12,493	13,007
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, 2012 and 2011	—	—
Common stock, $0.001 par value per share; authorized 1,400,000,000 shares, 492,495,100 shares issued and 457,048,970 shares outstanding at December 31, 2012, and 490,468,815 shares issued and 481,743,738 shares outstanding at December 31, 2011	1	1
Treasury stock, at cost, 35,446,130 and 8,725,077 shares, respectively	(594)	(125)
Additional paid-in capital	12,335	12,305
Accumulated deficit	(7,500)	(7,699)
Accumulated other comprehensive loss	(248)	(178)
Total Calpine stockholders' equity	3,994	4,304
Noncontrolling interest	62	60
Total stockholders' equity	4,056	4,364
Total liabilities and stockholders' equity	$ 16,549	$ 17,371

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, 2012, 2011 and 2010
(in millions)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Stockholders' Equity
Balance, December 31, 2009	$ 1	$ (3)	$ 12,256	$ (7,540)	$ (266)	$ (2)	$ 4,446
Treasury stock transactions	—	(2)	—	—	—	—	(2)
Stock-based compensation expense	—	—	24	—	—	—	24
Other	—	—	1	—	—	28	29
Net income	—	—	—	31	—	—	31
Other comprehensive income	—	—	—	—	141	—	141
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	—	—	—	—	(53)	—	(53)
Balance, December 31, 2011	$ 1	$ (125)	$ 12,305	$ (7,699)	$ (178)	$ 60	$ 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	—	—	—	—	(70)	—	(70)
Balance, December 31, 2012	$ 1	$ (594)	$ 12,335	$ (7,500)	$ (248)	$ 62	$ 4,056

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, 2012, 2011 and 2010
(in millions)

	2012	2011	2010
Cash flows from operating activities:			
Net income (loss)	$ 199	$ (189)	$ 31
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization expense[1]	605	587	615
Debt extinguishment costs	—	82	91
Deferred income taxes	1	(21)	(26)
Impairment losses	—	—	116
(Gain) loss on sale of power plants and other, net	(212)	13	(314)
Unrealized mark-to-market (gain) loss	(72)	(30)	56
(Income) from unconsolidated investments in power plants	(28)	(21)	(16)
Return on unconsolidated investments in power plants	24	6	11
Stock-based compensation expense	25	24	24
Other	1	6	1
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable	159	74	91
Derivative instruments, net	(52)	15	(52)
Other assets	(57)	1	277
Accounts payable and accrued expenses	(86)	28	(43)
Settlement of non-hedging interest rate swaps	156	189	69
Other liabilities	(10)	11	(2)
Net cash provided by operating activities	653	775	929
Cash flows from investing activities:			
Purchases of property, plant and equipment	(637)	(683)	(369)
Proceeds from sale of power plants, interests and other	825	13	954
Purchase of Bosque Energy Center, Conectiv assets and BRSP, net of cash	(432)	—	(1,680)
Cash acquired due to consolidation of OMEC	—	—	8
Return of investment from unconsolidated investments	5	—	—
Settlement of non-hedging interest rate swaps	(156)	(189)	(69)
(Increase) decrease in restricted cash	(59)	54	322
Purchases of deferred transmission credits	(12)	(31)	—
Other	(4)	—	3
Net cash used in investing activities	(470)	(836)	(831)
Cash flows from financing activities:			
Borrowings under First Lien Term Loans	835	1,657	—
Repayments of First Lien Term Loans	(19)	—	—
Repayments on NDH Project Debt	—	(1,283)	—
Issuance of First Lien Notes	—	1,200	3,491
Repayments of First Lien Notes	(590)	—	—
Repayments on First Lien Credit Facility	—	(1,195)	(3,477)
Borrowings from project financing, notes payable and other	389	327	1,272
Repayments of project financing, notes payable and other	(289)	(550)	(937)
Capital contributions from noncontrolling interest holder	—	33	17
Financing costs	(20)	(81)	(136)
Stock repurchases	(463)	(119)	—
Refund of financing costs	—	—	10
Other	6	(3)	—
Net cash provided by (used in) financing activities	(151)	(14)	240
Net increase (decrease) in cash and cash equivalents	32	(75)	338
Cash and cash equivalents, beginning of period	1,252	1,327	989
Cash and cash equivalents, end of period	$ 1,284	$ 1,252	$ 1,327

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)

(in millions)

		2012		2011		2010
Cash paid during the period for:						
Interest, net of amounts capitalized	$	719	$	656	$	635
Income taxes	$	16	$	18	$	21
Supplemental disclosure of non-cash investing and financing activities:						
Change in capital expenditures included in accounts payable	$	19	$	(24)	$	1
Other non-cash additions to property, plant and equipment	$	13	$	—	$	—
Liabilities assumed in BRSP acquisition	$	—	$	—	$	85
Conversion of project debt to noncontrolling interest	$	—	$	—	$	11

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

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

CALPINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the Years Ended December 31, 2012, 2011 and 2010

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 engage in the purchase of natural gas and fuel oil as fuel for our power plants and in related natural gas transportation and storage transactions, and in the purchase of electric transmission rights to deliver power to our customers. We also enter into natural gas and power physical and financial contracts to economically hedge our business risks and optimize our portfolio of power plants.

2. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

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

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.

Change in Presentation — We have changed the presentation on our Consolidated Statements of Operations to separately present our Commodity revenue, unrealized mark-to-market gain (loss) and other revenue which are components of operating revenues and our Commodity expense and unrealized mark-to-market (gain) loss which are components of fuel and purchased energy expense. The change in presentation had no impact on our financial condition, results of operations or cash flows.

Reclassification — We have reclassified RGGI compliance and other environmental costs previously recorded in other operating expenses of $10 million and $9 million to Commodity expense on our Consolidated Statements of Operations for the years ended December 31, 2011 and 2010, respectively, to conform to the current year presentation.

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, 2012	Ownership Interest	Property, Plant & Equipment	Accumulated Depreciation	Construction in Progress
	(in millions, except percentages)			
Freestone Energy Center...	75.0%	$ 392	$ (124)	$ 1
Hidalgo Energy Center......	78.5%	$ 252	$ (86)	$ —

Use of Estimates in Preparation of Financial Statements

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

Fair Value of Financial Instruments and Derivatives

The carrying values of accounts receivable, accounts payable and other receivables and payables approximate their respective fair values due to their short-term maturities. See Note 6 for disclosures regarding the fair value of our debt instruments and Notes 7 and 8 for disclosures regarding the fair values of our derivative instruments 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, 2012 and 2011, we had cash and cash equivalents of $131 million and $306 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, 2012 and 2011 (in millions):

	2012			2011		
	Current	Non-Current	Total	Current	Non-Current	Total
Debt service[1]	$ 11	$ 41	$ 52	$ 11	$ 42	$ 53
Construction/major maintenance	32	14	46	33	10	43
Security/project/insurance	101	3	104	79	—	79
Other	49	2	51	16	3	19
Total	$ 193	$ 60	$ 253	$ 139	$ 55	$ 194

(1) At both December 31, 2012 and 2011, amounts restricted for debt service included approximately $25 million 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, 2012 and 2011, we had inventory of $301 million and $294 million, respectively. Inventory primarily consists of spare parts, stored natural gas and fuel oil, emission reduction credits and natural gas exchange imbalances. Inventory, other than spare parts, is stated primarily at the lower of cost or market value under the weighted average cost method. Spare parts inventory is valued at weighted average cost and is expensed to plant operating expense or capitalized to property, plant and equipment as the parts are utilized and consumed.

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, repairs or replacements when they appreciably extend the life, increase the capacity or improve the efficiency or safety of the property. Such costs are expensed when they do not meet the above criteria. We purchased our Geysers Assets as a proven steam reservoir and accounted for the assets under purchase accounting. All well costs, except well workovers 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 land or have a favorable option to purchase the land at conclusion of the lease term and approximately 0.15% of the depreciable costs basis for 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 2012 and 2011, we did not record any impairment losses. During 2010, we impaired approximately $95 million related to South Point (see Note 3 for further information related to our acquisition of the South Point lease and subsequent impairment of our South Point assets) and development costs of approximately $21 million associated with two development projects that originated prior to our Chapter 11 bankruptcy proceedings. We continued to market these projects after our Effective Date, but during 2010 we determined that their continued development was unlikely.

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, 2012 and 2011, our asset retirement obligation liabilities were $38 million and $27 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, excluding tolling agreements related to power plants under construction, at December 31, 2012, are as follows (in millions):

2013	$	548
2014		446
2015		455
2016		397
2017		359
Thereafter		2,078
Total	$	4,283

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 a 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 gas transactions economically hedging anticipated future power sales that do not qualify for hedge accounting treatment.

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

Fair Value Measurement — In May 2011, the FASB issued Accounting Standards Update 2011-04, "Fair Value Measurement" to clarify and amend the application or requirements relating to fair value measurements and disclosures relating to fair value measurements. The update stems from the FASB and the International Accounting Standards Board project to develop common requirements for measuring fair value and for disclosing information about fair value measurements. The update did not impact any of our fair value measurements but did require disclosure of the following:

- quantitative information about the unobservable inputs used in a fair value measurement that is categorized within level 3 of the fair value hierarchy;
- for those fair value measurements categorized within level 3 of the fair value hierarchy, both the valuation processes used and the sensitivity of the fair value measurement to changes in unobservable inputs and the interrelationships between those unobservable inputs, if any; and
- the categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed.

The new requirements relating to fair value measurements are prospective and effective for interim and annual periods beginning after December 15, 2011, with early adoption prohibited. We adopted all of the requirements related to this update at January 1, 2012. Since this update did not impact any of our fair value measurements and only required additional disclosures, adoption of this standard did not have a material impact on our financial condition, results of operations or cash flows.

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. These updates only require additional disclosures, as such, the adoption of these standards will not have a material impact on our financial condition, results of operations or cash flows.

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. This update only requires additional disclosures, as such, the adoption of this standard will not have a material impact on our financial condition, results of operations or cash flows.

3. Acquisitions, Divestitures and Discontinued Operations

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. Although the purchase price allocation has not been finalized, we do not expect to record any material adjustments to the preliminary purchase price allocation nor do we expect to recognize any goodwill as a result of this acquisition.

Conectiv Acquisition

On July 1, 2010, we, through our indirect, wholly-owned subsidiary NDH, completed the Conectiv Acquisition. The assets acquired included 18 operating power plants and the York Energy Center that was under construction and achieved COD on March 2, 2011, totaling 4,491 MW of capacity. We did not acquire Conectiv's trading book, load serving auction obligations or collateral requirements. Additionally, we did not assume any of Conectiv's off-site environmental liabilities, environmental remediation liabilities in excess of $10 million related to assets located in New Jersey that are subject to ISRA, or pre-close accumulated pension and retirement welfare liabilities; however, we did assume pension liabilities on future services and compensation increases for past services for approximately 130 grandfathered union employees who joined Calpine as a result of the Conectiv Acquisition. During the second half of 2010, we initiated a voluntary retirement incentive program which reduced the number of employees covered by our pension obligation by 31 employees. The net proceeds of $1.3 billion received from the NDH Project Debt were used, together with available operating cash, to pay the Conectiv Acquisition purchase price of approximately $1.64 billion and also fund a cash contribution from Calpine Corporation to NDH of $110 million to fund completion of the York Energy Center. The NDH Project Debt was repaid in March 2011 with proceeds from borrowings under our 2018 First Lien Term Loans.

The Conectiv Acquisition provided us with a significant presence in the Mid-Atlantic market, one of the most robust competitive power markets in the U.S., and positioned us with three scale markets instead of two (California and Texas) giving us greater geographic diversity. We accounted for the Conectiv Acquisition under the acquisition method of accounting in accordance with U.S. GAAP.

The following table summarizes the pro forma operating revenues and net income (loss) attributable to Calpine for 2010 as if the Conectiv Acquisition had occurred on January 1, 2009. The pro forma information has been prepared by adding the preliminary, unaudited historical results of Conectiv, as adjusted for depreciation expense (utilizing the preliminary values assigned to the net assets acquired from Conectiv), interest expense from NDH Project Debt and income taxes to our historical results for the periods indicated below (in millions, except per share amounts).

		2010
Operating revenues	$	7,931
Net loss attributable to Calpine	$	(83)
Basic loss per common share attributable to Calpine	$	(0.17)
Diluted loss per common share attributable to Calpine	$	(0.17)

Acquisition of Broad River and South Point Leases

On December 8, 2010, we, through our indirect, wholly-owned subsidiary, Calpine BRSP, purchased entities from CIT Capital USA Inc. that held the leases for our Broad River and South Point power plants by assuming debt with a fair value of approximately $297 million and a cash payment of approximately $40 million. Prior to this purchase, our Broad River power plant was operated under a sale-leaseback transaction that was accounted for as a failed sale-leaseback financing transaction and our South Point power plant was accounted for as an operating lease. The purchase of the entities holding the power plant leases only added an incremental $85 million in consolidated debt, as the transaction eliminated approximately $212 million recorded as debt and accrued interest owed to CIT Capital USA Inc. under our Broad River power plant lease. The Calpine BRSP project debt was repaid in October 2012 with proceeds from borrowings under our 2019 First Lien Term Loan.

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

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

Broad River — Prior to the purchase, we operated the Broad River power plant under a lease that was accounted for as a failed sale-leaseback financing transaction under U.S. GAAP. The lease liability was included in project financing, notes payable and other debt balance and the power plant assets were included in our property, plant and equipment. As a result of the purchase, we did not adjust the historical value of the assets. We allocated the value of the consideration paid in the transaction based upon the fair value of both power plants, and the result was an allocation of assumed debt that was greater than the prior debt obligation resulting in a pre-tax loss of approximately $30 million. Because we primarily exchanged future lease obligations for a debt obligation, the resulting loss is recorded as debt extinguishment costs in accordance with U.S. GAAP.

South Point — Prior to the purchase, we accounted for the South Point lease as an operating lease. We allocated the consideration paid in the transaction based upon the fair value of both power plants. The result was an allocation of consideration paid for South Point that was in excess of the fair value of assets acquired by approximately $95 million, which was primarily due to the elimination of a lease levelization asset associated with the prior lease, which was no longer proper on a consolidated basis. The resulting loss has been reported as an impairment loss for accounting purposes.

While the transaction resulted in a one-time, pre-tax loss, in the longer-term, the acquisition of these entities grants us greater flexibility and more control of the future operation of both plants and simplified a previously complex leasing arrangement.

Sale of 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 expect to use 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 expect to use 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.

Sale of Blue Spruce and Rocky Mountain

On December 6, 2010, we, through our indirect, wholly-owned subsidiaries Riverside Energy Center, LLC and CDHI, completed the sale of 100% of our ownership interests in Blue Spruce and Rocky Mountain for approximately $739 million, and we recorded a pre-tax gain of approximately $209 million during the fourth quarter of 2010. The results of operations for Blue Spruce and Rocky Mountain are reported as discontinued operations on our Consolidated Statement of Operations for the year ended December 31, 2010.

Discontinued Operations

The table below presents the components of our discontinued operations for the period presented (in millions):

	2010
Operating revenues	$ 92
Gain on disposal of discontinued operations	209
Income from discontinued operations before taxes	43
Less: Income tax expense	59
Discontinued operations, net of tax	$ 193

Other Asset Sales

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

4. Property, Plant and Equipment, Net

As of December 31, 2012 and 2011, the components of property, plant and equipment, are stated at cost less accumulated depreciation as follows (in millions):

	2012	2011	Depreciable Lives
Buildings, machinery and equipment	$ 14,774	$ 15,074	3 – 47 Years
Geothermal properties	1,243	1,163	13 – 59 Years
Other	142	156	3 – 47 Years
	16,159	16,393	
Less: Accumulated depreciation	4,390	4,158	
	11,769	12,235	
Land	98	91	
Construction in progress	1,138	693	
Property, plant and equipment, net	$ 13,005	$ 13,019	

Total depreciation expense, including amortization of leased assets, recorded in income from operations and discontinued operations for the years ended December 31, 2012, 2011 and 2010, was $557 million, $560 million and $568 million, respectively.

We have various debt instruments that are collateralized by our property, plant and equipment. See Note 6 for a detailed 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 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, $24 million and $15 million for the years ended December 31, 2012, 2011 and 2010, 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, 2012. 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 with an aggregate capacity of 608 MW. 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 8,255 MW and 11,391 MW, at December 31, 2012 and 2011, 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. In addition to amounts contractually required, we provided support to these VIEs in the form of cash and other contributions of $20 million and $87 million for the years ended December 31, 2012 and 2011, respectively. During the year ended December 31, 2010, we provided $540 million to NDH, an indirect, wholly-owned subsidiary, to fund the Conectiv Acquisition, including $110 million to complete the construction of the York Energy Center. Additionally, we provided support to our other VIEs in the form of cash and other contributions other than amounts contractually required of $46 million during the year ended December 31, 2010.

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

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 on our Consolidated Balance Sheets. At December 31, 2012 and 2011, our equity method investments included on our Consolidated Balance Sheets were comprised of the following (in millions):

	Ownership Interest as of December 31, 2012	2012	2011
Greenfield LP	50%	$ 69	$ 72
Whitby	50%	12	8
Total investments		$ 81	$ 80

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, 2012 and 2011, equity method investee debt was approximately $448 million and $462 million, respectively, and based on our pro rata share of each of the investments, our share of such debt would be approximately $224 million and $231 million at December 31, 2012 and 2011, respectively.

Our equity interest in the net income from Greenfield LP and Whitby for the years ended December 31, 2012, 2011 and 2010, are 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		
	2012	2011	2010	2012	2011	2010
Greenfield LP	$ (17)	$ (12)	$ (8)	$ 22	$ 2	$ 6
Whitby	(11)	(9)	(8)	7	4	5
Total	$ (28)	$ (21)	$ (16)	$ 29	$ 6	$ 11

Greenfield LP — Greenfield LP is a limited partnership between certain subsidiaries of ours and of Mitsui & Co., Ltd. and contains the Greenfield Energy Centre, a 1,038 MW natural gas-fired, combined-cycle power plant located in Ontario, Canada which is operated by a third party. We and Mitsui & Co., Ltd. each hold a 50% interest in Greenfield LP. Greenfield LP holds an 18-year term loan with an original principal amount of CAD $648 million. Borrowings under the project finance facility bear interest at Canadian LIBOR plus 1.125% or Canadian prime rate plus 0.125%.

Whitby — Whitby is a limited partnership between certain subsidiaries of ours 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.

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

Significant Unconsolidated Subsidiaries — Greenfield LP and Whitby met the criteria of significant unconsolidated subsidiaries for the year ended December 31, 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, 2012 and 2011

	2012	2011
Assets:		
Cash and cash equivalents	64	76
Current assets	30	37
Property, plant and equipment, net	648	656
Other assets	4	3
Total assets	$ 742	$ 769
Liabilities:		
Current maturities of long-term debt	$ 25	$ 24
Current liabilities	36	47
Long-term debt	423	438
Long-term derivative liabilities	84	85
Total liabilities	568	594
Member's interest	178	178
Total liabilities and member's interest	746	1,295

Condensed Combined Statements of Operations
of Our Unconsolidated Subsidiaries
For the Years Ended December 31, 2012, 2011 and 2010

	2012	2011	2010
Revenues	$ 247	$ 277	$ 228
Operating expenses	171	208	183
Income from operations	76	69	45
Interest expense, net of interest income	27	30	27
Other (income) expense, net	(2)	2	—
Net income	$ 51	$ 37	$ 18

6. Debt

Our debt at December 31, 2012 and 2011, was as follows (in millions):

	2012	2011
First Lien Notes[1]	$ 5,303	$ 5,892
First Lien Term Loans[1]	2,463	1,646
Project financing, notes payable and other[1]	1,789	1,691
CCFC Notes	978	972
Capital lease obligations	217	224
Total debt	10,750	10,425
Less: Current maturities	115	104
Debt, net of current portion	$ 10,635	$ 10,321

(1) During the fourth quarter of 2012, we redeemed 10% of the aggregate principal amount of our First Lien Notes and repaid project debt with proceeds received from the issuance of our 2019 First Lien Term Loan.

Annual Debt Maturities

Contractual annual principal repayments or maturities of debt instruments as of December 31, 2012, are as follows (in millions):

2013	$ 115
2014	188
2015	153
2016	1,162
2017	1,597
Thereafter	7,580
Total debt	10,795
Less: Discount	45
Total	$ 10,750

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[1]	
	2012	2011	2012	2011
2017 First Lien Notes	$ 1,080	$ 1,200	7.5%	7.5%
2019 First Lien Notes	360	400	8.2	8.2
2020 First Lien Notes	983	1,092	8.1	8.1
2021 First Lien Notes	1,800	2,000	7.7	7.7
2023 First Lien Notes	1,080	1,200	8.0	8.0
Total First Lien Notes	$ 5,303	$ 5,892		

(1) 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.

On October 9, 2012, we issued notice to the holders of our First Lien Notes of our intent to redeem 10% of the aggregate principal amount of each series of our existing First Lien Notes. On November 7, 2012, we completed the redemption at a redemption price of 103% of the principal amount redeemed, plus accrued and unpaid interest. This redemption was funded using a portion of the proceeds received from the issuance of the 2019 First Lien Term Loan discussed further below.

First Lien Term Loans

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 2.25%, or (ii) LIBOR plus 3.25% per annum subject to a LIBOR floor of 1.25%. 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.

On October 9, 2012, we entered into and borrowed $835 million under our 2019 First Lien Term Loan, which bears interest at the same rate as our First Lien Term Loans (discussed above). We used the net proceeds received to redeem 10% of the aggregate principal amount of each series of our existing First Lien Notes at a redemption price of 103% of the principal amount redeemed and to repay project debt totaling $218 million, plus accrued and unpaid interest for each. The 2019 First Lien Term Loan allows us to reduce our overall cost of debt by replacing a portion of our First Lien Notes with fixed interest rates ranging from 7.25% to 8.0% with a corporate level term loan carrying a lower variable interest rate currently at 4.5% and to repay variable rate project debt.

The 2019 First Lien Term Loan carries substantially the same terms as the 2018 First Lien Term Loans and matures on October 9, 2019. The 2019 First Lien Term Loan also contains substantially similar covenants, qualifications, exceptions and limitations as the 2018 First Lien Term Loans and First Lien Notes. We recorded debt extinguishment costs of approximately $18 million associated with the redemption premium, the write-off of unamortized deferred financing costs and debt premium and discount during the fourth quarter of 2012.

	Outstanding at December 31,		Weighted Average Effective Interest Rates[1]	
	2012	2011	2012	2011
2018 First Lien Term Loans	$ 1,630	$ 1,646	4.7%	4.7%
2019 First Lien Term Loan	833	—	4.7	—
Total First Lien Term Loans	$ 2,463	$ 1,646		

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

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]	
	2012	2011	2012	2011
Russell City Project Debt due 2023	$ 507	$ 244	3.6%	4.1%
Steamboat due 2017	428	437	6.8	6.6
OMEC due 2019	345	355	6.8	6.8
Los Esteros Project Debt due 2023	209	83	3.5	3.8
Pasadena[2]	160	185	8.9	8.8
Bethpage Energy Center 3 due 2020-2025[3]	93	98	7.0	7.0
Gilroy note payable due 2014	33	49	10.8	10.6
Calpine BRSP due 2014[4]	—	232	—	5.7
Other	14	8	—	—
Total	$ 1,789	$ 1,691		

(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.

(4) During the fourth quarter of 2012, we repaid the Calpine BRSP project debt with proceeds received from the issuance of our 2019 First Lien Term Loan.

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 Notes

On May 19, 2009, our wholly-owned subsidiaries, CCFC and CCFC Finance, issued approximately $1.0 billion aggregate principal amount of 8.0% CCFC Notes in a private placement. The CCFC Notes and the related guarantees are secured, subject to certain exceptions and permitted liens, by all real and personal property of CCFC and CCFC's material subsidiaries (including the CCFC Guarantors), consisting primarily of six natural gas power plants as well as the equity interests in CCFC and the CCFC Guarantors. The CCFC Notes are not guaranteed by Calpine Corporation and are without recourse to Calpine Corporation or any of our other non-CCFC or CCFC Finance subsidiaries or assets; however, CCFC generates the majority of its cash flows from an intercompany tolling agreement with CES and has various service agreements in place with other subsidiaries of Calpine Corporation. The CCFC Notes mature on June 1, 2016 and the weighted average interest rates, which includes the amortization of deferred financing costs and debt discount, was 8.9% for both 2012 and 2011.

Capital Lease Obligations

The following is a schedule by year of future minimum lease payments under capital leases and failed sale-leaseback transactions together with the present value of the net minimum lease payments as of December 31, 2012 (in millions):

	Sale-Leaseback Transactions[1]	Capital Lease	Total
2013	$ 37	$ 42	$ 79
2014	25	43	68
2015	25	38	63
2016	25	41	66
2017	17	38	55
Thereafter	127	161	288
Total minimum lease payments	256	363	619
Less: Amount representing interest	96	146	242
Present value of net minimum lease payments	$ 160	$ 217	$ 377

(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 36 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, 2012 and 2011, the asset balances for the leased assets totaled approximately $880 million and $879 million with accumulated amortization of $312 million and $318 million, respectively. 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, 2012 and 2011 (in millions):

	2012	2011
Corporate Revolving Facility	$ 243	$ 440
CDHI	253	193
Various project financing facilities	130	130
Total	$ 626	$ 763

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 2.00% to 2.25% 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 3.00% to 3.25%. Interest payments are due on the last business day of each calendar quarter for base rate loans and the earlier of (i) the last day of the interest period selected or (ii) each day that is three months (or a whole multiple thereof) after the first day for the interest period selected for LIBOR rate loans. Letter of credit fees for issuances of letters of credit include fronting fees equal to that percentage per annum as may be separately agreed upon between us and the issuing lenders and a participation fee for the lenders equal to the applicable interest margin for LIBOR rate borrowings. Drawings under letters of credit shall be repaid within 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 0.50% to 0.75% on the unused amount of commitments under the Corporate Revolving Facility.

The Corporate Revolving Facility does not contain any requirements for mandatory prepayments, except in the case of certain designated asset sales in excess of $3 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 December 10, 2015.

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

CDHI

We also have a letter of credit facility related to CDHI. On January 10, 2012, we increased the CDHI letter of credit facility to $300 million and extended the maturity date to 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, 2012, we had $28 million of cash collateral posted in support of outstanding letters of credit under our CDHI letter of credit facility. We do not believe that this change will have a material impact on our liquidity.

Fair Value of Debt

We record our debt instruments based on contractual terms, net of any applicable premium or discount. We did not elect to apply the alternative U.S. GAAP provisions of the fair value option for recording financial assets and financial liabilities. The following table details the fair values and carrying values of our debt instruments at December 31, 2012 and 2011 (in millions):

	2012		2011	
	Fair Value	Carrying Value	Fair Value	Carrying Value
First Lien Notes	$ 5,863	$ 5,303	$ 6,219	$ 5,892
First Lien Term Loans	2,489	2,463	1,615	1,646
Project financing, notes payable and other[1]	1,599	1,629	1,467	1,504
CCFC Notes	1,075	978	1,070	972
Total	$ 11,026	$ 10,373	$ 10,371	$ 10,014

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

Derivatives — The primary factors affecting the fair value of our derivative instruments at any point in time are the volume of open derivative positions (MMBtu, MWh and $ notional amounts); 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 natural gas swaps, futures and options traded on the NYMEX.

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

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

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect our estimate of the fair value of our assets and liabilities and their placement within the fair value hierarchy levels. The following tables present our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 and 2011, by level within the fair value hierarchy:

	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 held by us posted 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

	Assets and Liabilities with Recurring Fair Value Measures as of December 31, 2011			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Cash equivalents[1]	$ 1,415	$ —	$ —	$ 1,415
Margin deposits	140	—	—	140
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	1,043	—	—	1,043
Commodity forward contracts[2]	—	74	37	111
Interest rate swaps	—	10	—	10
Total assets	$ 2,598	$ 84	$ 37	$ 2,719
Liabilities:				
Margin deposits held by us posted by our counterparties	$ 34	$ —	$ —	$ 34
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	899	—	—	899
Commodity forward contracts[2]	—	184	20	204
Interest rate swaps	—	320	—	320
Total liabilities	$ 933	$ 504	$ 20	$ 1,457

(1) As of December 31, 2012 and 2011, we had cash equivalents of $1,274 million and $1,249 million included in cash and cash equivalents and $228 million and $166 million included in restricted cash, respectively.

(2) Includes OTC swaps and options.

The following table sets forth a reconciliation of changes in the fair value of our net derivative assets (liabilities) classified as level 3 in the fair value hierarchy for the years ended December 31, 2012, 2011 and 2010 (in millions):

	2012	2011	2010
Balance, beginning of period	$ 17	$ 30	$ 38
Realized and unrealized gains (losses):			
Included in net income:			
Included in operating revenues[1]	8	5	7
Included in fuel and purchased energy expense[2]	—	—	—
Included in OCI	—	2	2
Purchases, issuances and settlements:			
Purchases	3	—	—
Issuances	(1)	—	—
Settlements	(11)	(18)	(20)
Transfers in and/or out of level 3[3]:			
Transfers into level 3[4]	—	(2)	—
Transfers out of level 3[5]	—	—	3
Balance, end of period	$ 16	$ 17	$ 30
Change in unrealized gains relating to instruments still held at end of period	$ 8	$ 5	$ 7

(1) For power contracts and Heat Rate swaps and options, 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 significant transfers into/out of level 1 during the years ended December 31, 2012, 2011 and 2010.

(4) There were no significant transfers into level 3 for the years ended December 31, 2012 and 2010. 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, 2012 and 2011. There were $3 million in losses transferred out of level 3 into level 2 for the year ended December 31, 2010 due to changes in market liquidity in various power markets.

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

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

8. Derivative Instruments

Types of Derivative Instruments and Volumetric Information

Commodity Instruments — We are exposed to changes in prices for the purchase and sale of power, natural gas and other energy commodities. We use derivatives, which include physical commodity contracts and financial commodity instruments such as OTC and exchange traded swaps, futures, options, forward agreements and instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) 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, 2012, the maximum length of time over which we were hedging using interest rate derivative instruments designated as cash flow hedges was 11 years.

As of December 31, 2012 and 2011, the net forward notional buy (sell) position of our outstanding commodity and interest rate swap contracts that did not qualify under the normal purchase normal sale exemption were as follows (in millions):

Derivative Instruments	Notional Amounts 2012	Notional Amounts 2011
Power (MWh)	(16)	(21)
Natural gas (MMBtu)	66	(200)
Interest rate swaps[(1)]	$ 1,602	$ 5,639

(1) Approximately $4.1 billion at December 31, 2011 was related to hedges of our First Lien Credit Facility's variable rate debt that was converted to fixed rate debt. On March 26, 2012, we terminated the interest rate swaps formerly hedging our First Lien Credit Facility.

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, 2012, was $5 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 additional collateral of $1 million would be required and that no counterparty could request immediate, full settlement.

Accounting for Derivative Instruments

We recognize all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for, and we elect, the normal purchase normal sale exemption. For transactions in which we elect the normal purchase normal sale exemption, gains and losses are not reflected on our Consolidated Statements of Operations until the 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 more volatility in our earnings. Revenues and fuel costs derived from instruments that qualified for hedge accounting or represent an economic hedge are recorded in the same financial statement line item as the item being hedged. Although we have discontinued the application of hedge accounting treatment for our commodity derivative instruments, prior to this change and for our interest rate swaps, hedge accounting requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. We present the cash flows from our derivatives in the same category as the item being hedged (or economically hedged) within operating activities or investing activities (in the case of settlements for our interest rate swaps formerly hedging our First Lien Credit Facility term loans) on our Consolidated 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 and interest rate transactions that primarily act as economic hedges to our asset and interest rate portfolio, but either do not qualify as hedges under the hedge accounting guidelines or qualify under the hedge accounting guidelines and the hedge accounting designation has not been elected. Changes in fair value of commodity derivatives not designated as hedging instruments are recognized currently in earnings and are separately stated on our Consolidated Statements of Operations in unrealized mark-to-market gain/loss as a component of operating revenues (for power contracts and Heat Rate swaps and options) and fuel and purchased energy expense (for natural gas contracts, swaps and options). 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 and Other Project Debt — During 2010, we repaid approximately $3.5 billion of our First Lien Credit Facility term loans, which had approximately $3.3 billion notional amount of interest rate swaps hedging the scheduled variable interest payments, and in January 2011, we repaid the remaining approximately $1.2 billion of First Lien Credit Facility term loans which had approximately $1.0 billion notional amount of interest rate swaps hedging the scheduled variable interest payments. With the repayment of the remaining First Lien Credit Facility term loans, unrealized losses of approximately $91 million in AOCI related to the interest rate swaps formerly hedging the First Lien Credit Facility, were reclassified out of AOCI and into earnings as an additional loss on interest rate derivatives during 2011. In addition, we reclassified approximately $17 million in unrealized losses in AOCI to loss on interest rate derivatives during 2011 resulting from the repayment of project debt in 2011. During 2010, we reclassified approximately $206 million out of AOCI and into earnings as additional loss on interest rate derivatives related to interest rate swaps formerly hedging our First Lien Credit Facility term loans. We have presented 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 described above separate from interest expense as loss on interest rate derivatives on our Consolidated Statements of Operations. On March 26, 2012, we terminated the legacy interest rate swaps formerly hedging our First Lien Credit Facility and paid 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

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, 2012 and 2011 (in millions):

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

	December 31, 2011		
	Interest Rate Swaps	Commodity Instruments	Total Derivative Instruments
Balance Sheet Presentation			
Current derivative assets	$ —	$ 1,051	$ 1,051
Long-term derivative assets	10	103	113
Total derivative assets	$ 10	$ 1,154	$ 1,164
Current derivative liabilities	$ 166	$ 978	$ 1,144
Long-term derivative liabilities	154	125	279
Total derivative liabilities	$ 320	$ 1,103	$ 1,423
Net derivative assets (liabilities)	$ (310)	$ 51	$ (259)

	December 31, 2012		December 31, 2011	
	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[(1)]:				
Interest rate swaps	$ 4	$ 184	$ 10	$ 149
Commodity instruments	—	—	51	18
Total derivatives designated as cash flow hedging instruments	$ 4	$ 184	$ 61	$ 167
Derivatives not designated as hedging instruments:				
Interest rate swaps	$ —	$ 16	$ —	$ 171
Commodity instruments	433	450	1,103	1,085
Total derivatives not designated as hedging instruments	$ 433	$ 466	$ 1,103	$ 1,256
Total derivatives	$ 437	$ 650	$ 1,164	$ 1,423

(1) Includes accumulated fair value of derivative instruments as of the date hedge accounting was discontinued, net of amortized fair value for settlement periods which have transpired.

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 in 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, 2012, 2011 and 2010 (in millions):

	2012	2011	2010
Realized gain (loss)[1]			
Interest rate swaps	$ (157)	$ (193)	$ (31)
Commodity derivative instruments	387	143	114
Total realized gain (loss)	$ 230	$ (50)	$ 83
Unrealized gain (loss)[2]			
Interest rate swaps	$ 154	$ 55	$ (199)
Commodity derivative instruments	(82)	(25)	143
Total unrealized gain (loss)	$ 72	$ 30	$ (56)
Total mark-to-market activity, net	$ 302	$ (20)	$ 27

(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 de-designation of interest rate swap cash flow hedges and related reclassification from AOCI into earnings, hedge ineffectiveness and adjustments to reflect changes in credit default risk exposure.

	2012	2011	2010
Realized and unrealized gain (loss)			
Derivatives contracts included in operating revenues	$ 187	$ (20)	$ (19)
Derivatives contracts included in fuel and purchased energy expense	118	138	276
Interest rate swaps included in interest expense	11	7	(7)
Loss on interest rate derivatives	(14)	(145)	(223)
Total mark-to-market activity, net	$ 302	$ (20)	$ 27

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, 2012 and 2011 (in millions):

	Gains (Loss) Recognized in OCI (Effective Portion)		Gain (Loss) Reclassified from AOCI into Income (Effective Portion)[1]		Gain (Loss) Reclassified from AOCI into Income (Ineffective Portion)	
	2012	2011	2012	2011	2012	2011
Interest rate swaps	$ (43)	$ (23)	$ (32) [2]	$ (138) [2]	$ —	$ (1)
Commodity derivative instruments	(38)	(71)	52 [3]	163 [3]	2	(2)
Total	$ (81)	$ (94)	$ 20	$ 25	$ 2	$ (3)

(1) Cumulative cash flow hedge losses, net of tax, remaining in AOCI were $242 million and $172 million at December 31, 2012 and 2011, respectively.

(2) Reclassification of losses from OCI to earnings consisted of $32 million from the reclassification of interest rate contracts due to settlement for each of the years ended December 31, 2012 and 2011, $15 million in losses from terminated interest rate contracts due to the repayment of project debt in 2011, and $91 million in losses from existing interest rate contracts

reclassified from OCI into earnings due to the refinancing of variable rate First Lien Credit Facility term loans for the year ended December 31, 2011.

(3) Included in Commodity revenue and Commodity expense on our Consolidated Statements of Operations.

As a result of our election to discontinue hedge accounting treatment for our commodity derivatives accounted for as cash flow hedges, the fair value of our commodity derivative instruments that previously resided in AOCI on the de-designation date was reclassified to earnings during 2012 as the related hedged transactions affected earnings. Thus, there is no fair value amounts related to commodity derivatives remaining in AOCI at December 31, 2012. We estimate that pre-tax net losses of $41 million (comprised of amounts related to interest rate swaps) would be reclassified from AOCI into earnings during the next 12 months as the hedged transactions settle; however, the actual amounts that will be reclassified will likely vary based on changes in 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, 2012 and 2011 (in millions):

	2012	2011
Margin deposits[1]	$ 196	$ 140
Natural gas and power prepayments	35	42
Total margin deposits and natural gas and power prepayments with our counterparties[2]	$ 231	$ 182
Letters of credit issued	$ 484	$ 581
First priority liens under power and natural gas agreements	14	1
First priority liens under interest rate swap agreements	206	318
Total letters of credit and first priority liens with our counterparties	$ 704	$ 900
Margin deposits held by us posted by our counterparties[1][3]	$ 11	$ 34
Letters of credit posted with us by our counterparties	1	—
Total margin deposits and letters of credit posted with us by our counterparties	$ 12	$ 34

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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.

(2) At December 31, 2012 and 2011, $211 million and $162 million, respectively, were included in margin deposits and other prepaid expense and $20 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, 2012, 2011 and 2010, are as follows (in millions):

	2012	2011	2010
U.S.	$ 194	$ (232)	$ (226)
International	24	20	(4)
Total	$ 218	$ (212)	$ (230)

The components of income tax expense (benefit) from continuing operations for the years ended December 31, 2012, 2011 and 2010, consisted of the following (in millions):

	2012	2011	2010
Current:			
Federal	$ (12)	$ (16)	$ (1)
State	16	12	10
Foreign	14	3	3
Total current	18	(1)	12
Deferred:			
Federal	11	(33)	(70)
State	(5)	9	—
Foreign	(5)	3	(10)
Total deferred	1	(21)	(80)
Total income tax expense (benefit)	$ 19	$ (22)	$ (68) [(1)]

(1) Includes approximately $13 million in intraperiod tax expense related to a prior period with an offsetting benefit in OCI.

For the years ended December 31, 2012, 2011 and 2010, 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, 2012, 2011 and 2010, is as follows:

	2012	2011	2010
Federal statutory tax expense (benefit) rate	35.0%	(35.0)%	(35.0)%
State tax expense, net of federal benefit	3.2	6.5	2.8
Depletion in excess of basis	(0.2)	—	(1.3)
Preferred interest expense	2.0	0.4	0.5
Federal refunds	(4.7)	—	—
Valuation allowances against future tax benefits	(32.3)	56.7	33.6
Valuation allowances related to reconsolidation of CCFC	—	(36.0)	—
Valuation allowances related to foreign taxes	(8.2)	—	—
Foreign taxes	3.7	(0.9)	9.9
Non-deductible reorganization items	0.1	0.5	0.3
Intraperiod allocation	4.6	19.9	(40.1)
Bankruptcy settlement	—	(15.7)	—
Change in unrecognized tax benefits	5.1	(6.6)	0.6
Permanent differences and other items	0.4	(0.2)	(0.9)
Effective income tax expense (benefit) rate	8.7%	(10.4)%	(29.6)%

Deferred Tax Assets and Liabilities

The components of the deferred income taxes as of December 31, 2012 and 2011, are as follows (in millions):

	2012	2011
Deferred tax assets:		
NOL and credit carryforwards	$ 3,073	$ 3,290
Taxes related to risk management activities and derivatives	90	58
Reorganization items and impairments	315	318
Foreign capital losses	25	24
Other differences	60	26
Deferred tax assets before valuation allowance	3,563	3,716
Valuation allowance	(2,222)	(2,336)
Total deferred tax assets	1,341	1,380
Deferred tax liabilities: property, plant and equipment	(1,316)	(1,364)
Net deferred tax asset	25	16
Less: Current portion deferred tax liability	(3)	(2)
Less: Non-current deferred tax asset	28	18
Deferred income tax liability, non-current	$ —	$ —

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. For the year ended December 31, 2010, the CCFC group was deconsolidated from the Calpine group for federal income tax reporting purposes.

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) and income from discontinued operations with a partial offsetting amount recognized in OCI and discontinued operations. The following table details the effects of our intraperiod tax allocations for the years ended December 31, 2012, 2011 and 2010 (in millions).

	2012	2011	2010
Intraperiod tax allocation expense (benefit) included in continuing operations	$ 9	$ 42	$ (86)
Intraperiod tax allocation expense included in discountinued operations	$ —	$ —	$ 59
Intraperiod tax allocation expense (benefit) included in OCI	$ (9)	$ (45)	$ 27

NOL Carryforwards — Our NOL carryforwards consist primarily of federal NOL carryforwards of approximately $7.3 billion, which expire between 2023 and 2031, and NOL carryforwards in 33 states and the District of Columbia totaling approximately $4.0 billion, which expire between 2013 and 2031, substantially all of which are offset with a full valuation allowance. We also have approximately $1.0 billion in foreign NOLs, 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. At December 31, 2012, approximately $2.4 billion of our $7.3 billion federal NOLs are not subject to annual Section 382 limitations. When considering our cumulative annual Section 382 limitations, in addition to our post-Effective Date NOLs that are not limited, our total unrestricted NOLs are approximately $7.1 billion. If a subsequent ownership change were to occur as a result of future transactions in our common 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 in 2012. 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 net operating tax 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 in 2012 due to NOL carryforwards, these "windfall" tax benefits are not reflected in our NOL in deferred tax assets for 2012. Windfalls included in NOL carryforwards, but not reflected in deferred tax assets as of December 31, 2012 were $10 million.

Under state income tax laws, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of the IRC. During 2011, we analyzed the effect of our change in ownership on the Effective Date for each of our significant states to determine the amount of our NOL limitation. The analysis determined that $640 million of our state NOLs are expected to expire unutilized as a result of statutory limitations on the use of some of our pre-emergence date NOLs as of the Effective Date or the cessation of business operations in various tax jurisdictions. We reduced our deferred tax asset for state NOLs that we are unable to utilize and made an equal reduction in our valuation allowance in 2011. The result did not have an impact on our income tax expense in 2011. We estimate that approximately $117 million of our state NOLs expired unutilized during 2012 as a result of statutory state limitations relating to the time period NOLs can be carried forward, and accordingly, we reduced our deferred tax asset and made an equal reduction in our valuation allowance. The reduction did not have an impact to our income tax expense in 2012. We will likely make future annual adjustments to our state NOLs that have expired or are limited under Section 382 of the IRC.

In 2011, we had certain intercompany accounts payable/receivable balances that were eliminated as part of the final steps of our emergence from bankruptcy. There was no effect to our federal NOLs, however, there was a reduction in our state NOLs of $44 million which was partially offset by a reduction in current state taxable income of $24 million. The resulting net reduction to our state NOLs was offset by an equal reduction in our valuation allowance. The reduction did not have an impact on our income tax expense in 2011.

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

Canadian Tax Audits — In September 2009, we received notice from the Canadian Revenue Authority, or CRA, of their intent to conduct a limited scope income tax audit on four of our Canadian subsidiaries for the tax years 2005 through 2008. The CRA concluded that there were no adjustments on two of the subsidiaries, but further review was required on the remaining two subsidiaries. On April 23, 2012, the remaining two subsidiaries received proposed adjustments from the CRA regarding our transfer pricing positions. On June 21, 2012, we met with the CRA to discuss their proposed adjustments and provided clarification where we believed it was needed. In July 2012, we received additional questions from the CRA as a result of our meeting, and we responded to their request in September and October 2012. In December 2012, we received and responded to additional questions from the CRA. In January 2013, we received an adjusted reassessment on one of the two transfer pricing issues that we are disputing with the CRA and are currently evaluating the merits of the adjusted reassessment. If accepted, any adjustments to our transfer pricing would increase taxable income and would be offset entirely by existing NOL's to which a valuation allowance has been applied. Any interest assessments resulting from acceptance of the CRA offer would be immaterial.

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

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

As of December 31, 2012, 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 decrease of $114 million, $50 million and $186 million for the years ended December 31, 2012, 2011 and 2010, respectively; all primarily related to changes in our estimates of our ability to utilize our NOL carryforwards.

Unrecognized Tax Benefits

At December 31, 2012, we had unrecognized tax benefits of $92 million. If recognized, $36 million of our unrecognized tax benefits could impact the annual effective tax rate and $56 million, related to deferred tax assets, could be offset against the recorded valuation allowance resulting in no impact to our effective tax rate. We also had accrued interest and penalties of $24 million for income tax matters at December 31, 2012. We recognize interest and penalties related to unrecognized tax benefits in income tax expense (benefit) on our Consolidated Statements of Operations. We believe that it is reasonably possible that a decrease within the range of approximately nil and $28 million in unrecognized tax benefits could occur within the next 12 months primarily related to state and foreign tax issues.

A reconciliation of the beginning and ending amounts of our unrecognized tax benefits for the years ended December 31, 2012, 2011 and 2010, is as follows (in millions):

	2012	2011	2010
Balance, beginning of period	$ (74)	$ (88)	$ (98)
Increases related to prior year tax positions	(19)	—	(1)
Decreases related to prior year tax positions	1	1	11
Decrease related to lapse of statute of limitations	—	13	—
Balance, end of period	$ (92)	$ (74)	$ (88)

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

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. Accordingly, although the reserved shares were not issued and outstanding for the entire balance of the periods presented, all conditions of distribution had been met for these reserved shares as of the Effective Date, and such shares are considered issued and are included in our calculation of weighted average shares outstanding. We also include restricted stock units for which no future service is required as a condition to the delivery of the underlying common stock in our calculation of weighted average shares outstanding.

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, 2012, 2011 and 2010, are as follows (shares in thousands):

	2012	2011	2010
Diluted weighted average shares calculation:			
Weighted average shares outstanding (basic)	467,752	485,381	486,044
Share-based awards	3,591	—	1,250
Weighted average shares outstanding (diluted)	471,343	485,381	487,294

We excluded the following items from diluted earnings (loss) per common share for the years ended December 31, 2012, 2011 and 2010, because they were anti-dilutive (shares in thousands):

	2012	2011	2010
Share-based awards	10,302	15,260	14,883

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 options 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, 2012, there were 567,000 and 27,533,000 shares of our common stock authorized for issuance to participants under the Director Plan and the Equity Plan, respectively.

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

Stock-based compensation expense recognized was $25 million, $24 million and $24 million for the years ended December 31, 2012, 2011 and 2010, 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, 2012, 2011 and 2010. At December 31, 2012, there was unrecognized compensation cost of $6 million related to options, $25 million related to restricted stock and nil related to restricted stock units, which is expected to be recognized over a weighted average period of 0.8 years for options, 1.3 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, 2012, is as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding — December 31, 2011	17,665,902	$ 17.32	4.8	$ 26
Granted	898,115	$ 15.35		
Exercised	348,500	$ 14.94		
Forfeited	187,716	$ 13.42		
Expired	165,300	$ 17.77		
Outstanding — December 31, 2012	17,862,501	$ 17.30	4.0	$ 42
Exercisable — December 31, 2012	10,251,149	$ 19.16	3.6	$ 12
Vested and expected to vest – December 31, 2012	17,588,775	$ 17.34	3.9	$ 41

The total intrinsic value of our employee stock options exercised was $1 million, nil and nil for the years ended December 31, 2012, 2011 and 2010, respectively. The total cash proceeds received from our employee stock options exercised was $5 million, nil and nil for the years ended December 31, 2012, 2011 and 2010, respectively.

The fair value of options granted during the years ended December 31, 2012, 2011 and 2010, was determined on the grant date using the Black-Scholes option-pricing model or the Monte Carlo simulation model, as appropriate. Certain assumptions were used in order to estimate fair value for options as noted in the following table.

	2012	2011	2010
Expected term (in years)[1]	6.5	6.5	4.0 – 6.5
Risk-free interest rate[2]	1.2 – 1.6 %	1.7 – 3.2 %	1.3 – 3.3 %
Expected volatility[3]	27.0 – 30.5 %	31.2 – 44.9 %	31.4 – 37.6 %
Dividend yield[4]	—	—	—
Weighted average grant-date fair value (per option)	$ 5.18	$ 5.49	$ 1.98

(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.

No restricted stock or restricted stock units have been granted other than under the Calpine Equity Incentive Plans. A summary of our restricted stock and restricted stock unit activity for the Calpine Equity Incentive Plans for the year ended December 31, 2012, is as follows:

	Number of Restricted Stock Awards	Weighted Average Grant-Date Fair Value
Nonvested — December 31, 2011	3,510,358	$ 12.10
Granted	1,991,894	$ 15.97
Forfeited	297,166	$ 13.70
Vested	1,071,049	$ 10.17
Nonvested — December 31, 2012	4,134,037	$ 14.33

The total fair value of our restricted stock and restricted stock units that vested during the years ended December 31, 2012, 2011 and 2010, was approximately $20 million, $7 million and $4 million, respectively.

13. Defined Contribution and Defined Benefit Plans

We maintain two defined contribution savings plans that are intended to be tax exempt under Sections 401(a) and 501 (a) of the IRC. Our non-union plan generally covers employees who are not covered by a collective bargaining agreement, and our union plan covers employees who are covered by a collective bargaining agreement. We recorded expenses for these plans of approximately $11 million, $10 million and $9 million for the years ended December 31, 2012, 2011 and 2010, 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.

As part of the Conectiv Acquisition, we assumed approximately $6 million of pension liability for approximately 130 grandfathered union employees who joined Calpine as a result of the Conectiv Acquisition and enrolled them into the New Development Holdings, LLC Union Retirement Plan, a defined benefit plan. PHI retained the pension liability associated with prior service cost; however, we are responsible for benefits for services after July 1, 2010 and future compensation increases related to prior service. During the second half of 2010, we initiated a voluntary retirement incentive program which reduced our pension obligation by 31 employees. Under the New Development Holdings, LLC Union Retirement Plan, retirement benefits are primarily a function of age attained, years of participation, years of service, vesting and level of compensation. As of December 31, 2012 and 2011, our pension assets, liabilities and related costs were not material to us. As of December 31, 2012 and 2011, there were approximately $12 million and $10 million in plan assets and approximately $21 million and $18 million in pension liabilities, respectively. Our net pension liability recorded on our Consolidated Balance Sheets as of December 31, 2012 and 2011, was approximately $9 million and $8 million, respectively. For the years ended December 31, 2012, 2011 and 2010, we recognized net periodic benefit costs of approximately $1 million, $1 million and $9 million, respectively. Net pension benefit costs for 2010 includes a one-time charge to pension expense for a voluntary retirement incentive program of approximately $8 million. The voluntary retirement incentive program was accepted by 31 of the 48 eligible employees that were retained as part of the Conectiv Acquisition allowing these employees the ability to commence receiving retirement benefits early without reducing their overall pension benefits. Our net periodic benefit cost is included in plant operating expense on our Consolidated Statements of Operations. As of December 31, 2012 and 2011, the total amount recognized in AOCI for actuarial losses related to pension obligation was approximately $1 million and $3 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 2012 and 2011, we made contributions of approximately $2 million and $3 million, respectively, and estimated contributions to the pension plan are expected to be approximately $1 million in 2013. 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, 2012 and 2011, was 492,495,100 shares and 490,468,815 shares, respectively, at a par value of $0.001 per share. Common stock outstanding as of December 31, 2012 and 2011, was 457,048,970 shares and 481,743,738 shares, respectively. The table below summarizes our common stock activity for the years ended December 31, 2012, 2011 and 2010.

	Shares Issued	Shares Held in Treasury	Shares Held in Reserve	Total
Balance, December 31, 2009	443,325,827	(327,572)	44,747,044	487,745,299
Resolution of claims	488,612	—	(488,612)	—
Shares issued under Calpine Equity Incentive Plans	1,068,917	(120,586)	—	948,331
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

Treasury Stock

As of December 31, 2012 and 2011, we had treasury stock of 35,446,130 shares and 8,725,077 shares, respectively, with a cost of $594 million and $125 million, respectively. On August 23, 2011, we announced that our Board of Directors had authorized the repurchase of up to $300 million in shares of our common stock. In April 2012, our Board of Directors authorized us to double the size of our share repurchase program, increasing our permitted cumulative repurchases to $600 million in shares of our common stock. As of the filing of this Report, we have completed our previously announced $600 million share repurchase program, having repurchased a total of 35,568,833 shares of our outstanding common stock at an average price paid of $16.87 per share. In February 2013, our Board of Directors authorized the repurchase of an additional $400 million in shares of our common stock, bringing the cumulative authorization total to $1.0 billion. 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. All treasury stock is held at cost.

15. Commitments and Contingencies

Long-Term Service Agreements

As of December 31, 2012, the total estimated commitments for LTSAs associated with turbines installed or in storage were approximately $68 million. These commitments are payable over the terms of the respective agreements, which range from 1 to 5 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 lease payments under these leases are as follows (in millions):

	Initial Year	2013	2014	2015	2016	2017	Thereafter	Total
Land and other operating leases .	various	$ 14	$ 14	$ 14	$ 15	$ 15	$ 228	$ 300
Power plant operating leases:								
Greenleaf..........	1998	$ 7	$ 3	$ —	$ —	$ —	$ —	$ 10
KIAC	2000	24	24	23	22	22	52	167
Total power plant leases..................		$ 31	$ 27	$ 23	$ 22	$ 22	$ 52	$ 177
Total leases.......		$ 45	$ 41	$ 37	$ 37	$ 37	$ 280	$ 477

During the years ended December 31, 2012, 2011 and 2010, rent expense for power plant and land and other operating leases amounted to $51 million, $53 million and $60 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, 2012, 2011 and 2010, were $22 million, $22 million and $25 million, respectively.

Office Leases

We lease our corporate and regional offices under noncancellable operating leases extending through 2020. Future minimum lease payments under these leases are as follows (in millions):

2013	$	12
2014		12
2015		12
2016		12
2017		12
Thereafter		31
Total	$	91

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, 2012, 2011 and 2010, rent expense for noncancellable operating leases was $12 million, $13 million and $12 million, respectively.

Natural Gas Purchases

We enter into natural gas purchase contracts of various terms with third parties to supply natural gas to our natural gas-fired power plants. The majority of our purchases are made in the spot market or under index-priced contracts. At December 31, 2012, we had future commitments of approximately $3.0 billion for natural gas purchases under contracts with terms from 1 to 13 years, and one contract with a term of 29 years.

Guarantees and Indemnifications

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

At December 31, 2012, 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	2013	2014	2015	2016	2017	Thereafter	Total
Guarantee of subsidiary debt(1)	$ 47	$ 36	$ 37	$ 36	$ 26	$ 209	$ 391
Standby letters of credit(2)(4)	536	41	—	—	19	30	626
Surety bonds(3)(4)(5)	—	—	—	—	—	4	4
Guarantee of subsidiary operating lease payments(4)	7	3	—	—	—	—	10
Total	$ 590	$ 80	$ 37	$ 36	$ 45	$ 243	$ 1,031

(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, 2012, $3 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 or warranty by the indemnifying party. These indemnification obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or impossible to quantify at the time of the consummation of a particular transaction.

Other — Additionally, we and our subsidiaries from time to time assume other guarantee and indemnification obligations in conjunction with other transactions such as parts supply agreements, construction agreements and equipment lease agreements. These guarantee and indemnification obligations may include future payment obligations and effectively guarantee our future performance under certain agreements.

Our potential exposure under guarantee and indemnification obligations can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. Our total maximum exposure under our guarantee and indemnification obligations is not estimable due to uncertainty as to whether claims will be made or how any potential claim will be resolved. As of December 31, 2012, there are no outstanding claims related to our guarantee and indemnification obligations and we do not anticipate that we will be required to make any material payments under our guarantee and indemnification obligations.

Litigation

We are party to various litigation matters, including regulatory and administrative proceedings arising out of the normal course of business. 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, 2012, 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, 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 (1)(2)	$ 994	$ 570	$ 729	$ 245	$ —	$ 2,538
Add: Unrealized mark-to-market commodity activity, net and other(3)	(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 and discontinued operations						$ 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[1][2]	$ 1,061	$ 469	$ 704	$ 240	$ —	$ 2,474
Add: Unrealized mark-to-market commodity activity, net and other[3]	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 and discontinued operations						$ (211)

	Year Ended December 31, 2010					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$ 2,525	$ 2,162	$ 978	$ 880	$ —	$ 6,545
Intersegment revenues	12	22	6	138	(178)	—
Total operating revenues	$ 2,537	$ 2,184	$ 984	$ 1,018	$ (178)	$ 6,545
Commodity Margin[1][2]	$ 1,080	$ 504	$ 535	$ 272	$ —	$ 2,391
Add: Unrealized mark-to-market commodity activity, net and other	69	89	21	22	(30)	171
Less:						
Plant operating expense	351	285	138	123	(29)	868
Depreciation and amortization expense	207	150	111	109	(7)	570
Sales, general and other administrative expense	55	38	45	12	1	151
Other operating expenses	59	2	28	4	(2)	91
Impairment losses	97	—	—	19	—	116
(Gain) on sale of assets, net	—	(119)	—	—	—	(119)
(Income) from unconsolidated investments in power plants	—	—	(16)	—	—	(16)
Income from operations	380	237	250	27	7	901
Interest expense, net of interest income						802
Loss on interest rate derivatives						223
Debt extinguishment costs and other (income) expense, net						106
Loss before income taxes and discontinued operations						$ (230)

(1) Our North segment includes Commodity Margin related to Riverside Energy Center, LLC of $73 million , $70 million and $73 million for the years ended December 31, 2012, 2011 and 2010, respectively.

(2) Our Southeast segment includes Commodity Margin related to Broad River of $52 million, $51 million and $55 million for the years ended December 31, 2012, 2011 and 2010, respectively.

(3) Includes $1 million and $12 million of lease levelization and $14 million and $8 million of amortization expense for the years ended December 31, 2012 and 2011, respectively, related to contracts that became effective in 2011.

Significant Customer

For the years ended December 31, 2012 and 2011, we had one significant customer, PJM Settlement, Inc., that accounted for more than 10% of our annual consolidated revenues. Our revenues of $713 million and $742 million from PJM Settlement, Inc. for the years ended December 31, 2012 and 2011, respectively, were attributed to our North segment. Our receivables from PJM Settlement, Inc. were $37 million and $28 million as of December 31, 2012 and 2011, respectively. We did not have a customer that accounted for more than 10% of our annual consolidated revenues for the year ended December 31, 2010.

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)			
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)
2011				
Operating revenues	$ 1,459	$ 2,209	$ 1,633	$ 1,499
Income from operations	$ 196	$ 403	$ 183	$ 18
Net income (loss) attributable to Calpine	$ (13)	$ 190	$ (70)	$ (297)
Net income (loss) per common share attributable to Calpine — Basic	$ (0.03)	$ 0.39	$ (0.14)	$ (0.61)
Net income (loss) per common share attributable to Calpine — Diluted	$ (0.03)	$ 0.39	$ (0.14)	$ (0.61)

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, 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
Year ended December 31, 2010					
Allowance for doubtful accounts	$ 14	$ (12)	$ —	$ —	$ 2
Deferred tax asset valuation allowance	2,572	(186)	—	—	2,386

(1) Represents write-offs of accounts considered to be uncollectible and previously reserved.

Board of Directors

J. Stuart Ryan (N)
Chairman of the Board
Chief Executive Officer, 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

David C. Merritt (A)
President, 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

William E. Oberndorf (C)
Chairman, Oberndorf Enterprises, LLC

Denise M. O'Leary (C)(N)
Private Venture Capital Investor

(A) Audit Committee
(C) Compensation Committee
(N) Nominating and Governance Committee

Executive Management

Jack A. Fusco
Chief Executive Officer

John B. (Thad) Hill
President and Chief Operating Officer

W. Thaddeus Miller
Executive Vice President, Chief Legal Officer and
Corporate Secretary

Zamir Rauf
Executive Vice President and Chief Financial Officer

General Information

Corporate Headquarters
Calpine Corporation
717 Texas Avenue, Suite 1000
Houston, Texas 77002
(713) 830-2000
www.calpine.com

Investor Relations
Calpine Corporation Investor Relations
(713) 830-8775
investor-relations@calpine.com

Independent Auditor
Pricewaterhouse Coopers LLP
Houston, Texas

Transfer Agent
Computershare, Inc.
P.O. Box 43078
Providence, RI 02940-3078
(877) 745-9351

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, 2012, 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 Friday, May 10, 2013, 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, 2012, 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
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