CALPINE CORP

FORM 8-K
(Current report filing)

Filed 07/29/11 for the Period Ending 07/29/11

Address	717 TEXAS AVENUE SUITE 1000 HOUSTON, TX 77002
Telephone	7138302000
CIK	0000916457
Symbol	CPN
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): **July 29, 2011**

CALPINE CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**1-12079**	**77-0212977**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

717 Texas Avenue, Suite 1000, Houston, Texas 77002
(Addresses of principal executive offices and zip codes)

Registrant's telephone number, including area code: **(713) 830-8775**

Not applicable
(Former name or former address if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

- ☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
- ☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
- ☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
- ☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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ITEM 2.02 — RESULTS OF OPERATIONS AND FINANCIAL CONDITION

On July 29, 2011 Calpine Corporation (the "Company") issued a press release announcing its financial and operating results for the quarter ended June 30, 2011. A copy of the press release is being furnished as Exhibit 99.1 hereto and is incorporated by reference herein. As set forth in the press release, the Company will host a conference call to discuss its financial and operating results for the second quarter of 2011 on Friday, July 29, 2011, at 10 a.m. ET / 9 a.m. CT. A listen-only webcast of the call may be accessed through the Company's website at www.calpine.com, or by dialing 877-874-1588 at least 10 minutes prior to the beginning of the call.

An archived recording of the call will be made available for a limited time on the Company's website and can also be accessed by dialing 888-203-1112 (or 719-457-0820 for international listeners) and providing confirmation code 1100419. Presentation materials to accompany the conference call will be made available on the Company's website on July 29, 2011.

The information in this Form 8-K, including Exhibit 99.1, shall not be deemed "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended (the "1934 Act"), nor shall it be deemed "incorporated by reference" into any filing under the Securities Act of 1933, as amended, or the 1934 Act, except as may be expressly set forth by specific reference in such filing.

ITEM 9.01 — FINANCIAL STATEMENTS AND EXHIBITS

(d) *Exhibits*

Exhibit No.	Description
99.1	Calpine Corporation Press Release dated July 29, 2011.*

* Furnished herewith.

SIGNATURES

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

CALPINE CORPORATION

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

Date: July 29, 2011

EXHIBIT INDEX

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* Furnished herewith.

EXHIBIT 99.1

CONTACTS:

NEWS RELEASE

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CALPINE CORP. REPORTS SOLID SECOND QUARTER 2011 RESULTS, UPDATES AND TIGHTENS 2011 GUIDANCE

Recent Achievements:

- Operations:
  - Achieved 98% fleet-wide starting reliability; highest second quarter performance on record
  - Produced 20 million MWh [1] of electricity in the second quarter of 2011
- Commercial:
  - Executed ten-year PPA with Entergy Texas for full output of 485 MW Carville Energy Center
- Financial:
  - Secured approximately $845 million credit facility to finance construction of 619 MW combined-cycle Russell City Energy Center, in which Calpine owns a 75% interest
  - Secured $360 million term loan to migrate project debt to the corporate level, simplifying our capital structure and relieving cash restrictions
- Regulatory:
  - Maintained active advocacy at state and federal levels
- Corporate:
  - Achieved settlement of all remaining bankruptcy claims and distributed more than half of all shares from reserve fund, marking important progress toward bankruptcy case closure

Second Quarter 2011 Financial Results:

- $406 million of Adjusted EBITDA
- $41 million of Adjusted Recurring Free Cash Flow
- $602 million of Commodity Margin
- $70 million of Net Loss [2]

June YTD 2011 Financial Results:

- $709 million of Adjusted EBITDA
- $20 million of Adjusted Recurring Free Cash Flow
- $1,091 million of Commodity Margin
- $367 million of Net Loss [2]

Updating and Tightening 2011 Full Year Guidance:

- 2011 Adjusted EBITDA guidance of $1,700 - $1,750 million (previously $1,700 - $1,800 million)
- 2011 Adjusted Recurring Free Cash Flow guidance of $475 - $525 million (previously $440 - $540 million)

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[1] Includes generation from unconsolidated power plants and plants owned but not operated by Calpine.
[2] Reported as net loss attributable to Calpine on our Consolidated Condensed Statements of Operations.

(HOUSTON, Texas) July 29, 2011 – Calpine Corporation (NYSE: CPN) today reported second quarter 2011 Adjusted EBITDA of $406 million, compared to $381 million in the prior year second quarter, and second quarter 2011 Adjusted Recurring Free Cash Flow of $41 million, compared to $131 million in the second quarter of 2010. Net Loss [2] for the quarter improved to $70 million, or $0.14 per diluted share, compared to a Net Loss of $115 million, or $0.24 per diluted share, in the 2010 period.

"We are pleased to report solid operating and financial results during the second quarter, demonstrating our consistent focus on serving customers, enhancing our balance sheet and delivering financially disciplined growth," said Jack Fusco, Calpine's President and Chief Executive Officer. "From an operating perspective, we produced 20 million MWh [1] of power while achieving second quarter and year-to-date starting reliability of 98%, the highest on record. This achievement was that much more remarkable because it was achieved against the backdrop of the highest number of turbine starts on record, showing that our reliable and flexible fleet of efficient, modern generation assets continues to deliver when our customers need us. On the expense side, we reduced second quarter plant operating expense [3] for our legacy fleet compared to the same period in 2010, and sales, general and administrative expense [4] was flat despite a net capacity increase of nearly 3,400 MW across the portfolio year over year. Commodity Margin was up significantly and Adjusted EBITDA increased by 7% versus last year's second quarter, in each case primarily due to the strategic acquisition of the Mid-Atlantic plants last July. As a result of this performance, we are updating and tightening our 2011 guidance – we now project full year Adjusted EBITDA of $1,700 million to $1,750 million, within the guidance range we provided late last year, and we are raising our Adjusted Free Cash Flow guidance to $475 million to $525 million.

"In addition, it is worth mentioning some developments that could positively impact Calpine in the future. On the environmental regulatory front, we note that the EPA's proposed Toxics Rule and the more recently issued CSAPR rule are likely to have a meaningful impact on the shape of the industry over the next several years. These rules are, in our view, long overdue and justified. Indeed, Calpine's investment thesis has, at its core, long anticipated these and other changes that should position the company well for the new landscape. That said, there will be continued attempts to delay, amend or override these rules. We have been and will continue to be a voice of reason in the debate. On the competitive markets front, we have observed efforts that will challenge competition, ranging from state subsidization of new construction to demand response mechanisms that carry little disincentive to abuse. We will continue to strenuously oppose these encroachments so that competitive markets can continue to deliver lower prices than fully regulated markets. More positively, we see signs that markets are beginning to understand the value of the flexibility that modern, clean and efficient natural gas-fired combined-cycle generation provides, particularly given the need to integrate renewable generation into the grid. On balance, we believe the march toward environmental change is relentless and the commitment to competitive markets, while still maturing, remains steadfast."

Zamir Rauf, Calpine's Chief Financial Officer, added, "From a balance sheet perspective, we successfully refinanced $360 million of project level debt at the corporate level, simplifying our capital structure and releasing restricted cash. We also closed on the project financing to fund construction of our Russell City Energy Center. Construction efforts are well underway at Russell City, as well as at Los Esteros, where project financing is in advanced stages. We remain on budget and on schedule for both of these significant growth projects. On the bankruptcy front, we made meaningful headway toward closing the book by settling all outstanding disputed claims. As a consequence we have issued over half of the remaining reserve shares that had been set aside to satisfy bankruptcy claims, and we expect to distribute the remaining shares over the next several months. It is important to recall that the sale and distributions have no dilutive effect, as they have always been included in our calculation of outstanding shares.

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[3] Increase in plant operating expense excludes changes in major maintenance expense, stock-based compensation expense, non-cash loss on disposition of assets and acquisition-related costs. See the table titled "Consolidated Adjusted EBITDA Reconciliation" for the actual amounts of these items for the six months ended June 30, 2011 and 2010.

[4] Increase in sales, general and administrative expense excludes changes in stock-based compensation and acquisition-related costs. See the table titled "Consolidated Adjusted EBITDA Reconciliation" for the actual amounts of these items for the six months ended June 30, 2011 and 2010.

"Also during the second quarter and since, we conducted the initial phases of an auction process for our Broad River and Mankato Energy Centers. As we explained when we announced the auction, we would be financially disciplined and sell the assets only if the value offered exceeded the value of the assets to us, including the associated long-term contracts and the optionality for growth at the sites. The bids did not meet these criteria and, as a result, we have concluded the auction process and are pleased to retain these quality plants as part of the Calpine fleet."

SUMMARY OF FINANCIAL PERFORMANCE

Second Quarter Results

Adjusted EBITDA for the second quarter of 2011 increased to $406 million compared to $381 million in the second quarter of 2010. The increase was primarily due to a $69 million improvement in Commodity Margin, to $602 million in the second quarter of 2011 from $533 million in the second quarter of 2010. The year-over-year increase was primarily due to our North segment, where Commodity Margin increased by $100 million due largely to the acquisition of our Mid-Atlantic fleet, which closed on July 1, 2010. This increase was offset, in part, by a $22 million decrease in Commodity Margin from our West segment. Despite higher average hedge prices year-over-year, Commodity Margin in the West declined primarily as a result of a decrease of $10 million in renewable energy credit (REC) revenue relating to the timing of the receipt of CPUC approval of new contracts associated with our Geysers assets in the second quarter of 2010, as well as lower market heat rates on our off-peak open position driven by increased hydroelectric generation in California and from an unscheduled outage at Otay Mesa Energy Center (OMEC) during the second quarter of 2011.

Offsetting the year-over-year increase in Commodity Margin, Adjusted EBITDA was negatively impacted by a $20 million decrease in Adjusted EBITDA from discontinued operations associated with the sale of our Colorado plants in December 2010. Also contributing to the offset, other revenue decreased by $16 million compared to the first quarter of 2011 due to favorable major maintenance contract revenue adjustments that were recognized in the second quarter of 2010.

Net Loss [2] was $70 million for the three months ended June 30, 2011, compared to a Net Loss of $115 million in the prior year period. As detailed in Table 1, Net Loss, As Adjusted, was $55 million in the second quarter of 2011 compared to $43 million in the second quarter of 2010. Though Commodity Margin increased, as previously discussed, this improvement was offset by increases in plant operating expense associated with the acquisition of our Mid-Atlantic fleet as well as higher major maintenance resulting from our plant outage schedule. In addition, income tax expense increased by $12 million year-over-year, primarily as a result of an increase of $49 million related to the application of intraperiod tax allocation partially offset by a decrease in federal income tax of $20 million and various state and foreign jurisdiction income taxes of $16 million.

Year-to-Date Results

Adjusted EBITDA for the six months ended June 30, 2011, was $709 million as compared to $663 million in the prior year period. The year-over-year increase in Adjusted EBITDA was primarily the result of a $128 million increase in Commodity Margin due in large part to our North segment, where Commodity Margin increased by $183 million primarily driven by the acquisition of our Mid-Atlantic plants, higher spark spreads on open positions at our legacy power plants due to higher market heat rates, and higher average hedge prices during the first half of 2011. Partially offsetting the increase in the North region, our Texas segment experienced a $40 million decline in Commodity Margin. Despite an increase in average hedge prices, our Texas segment was negatively impacted by unplanned outages during an extreme cold weather event in early February 2011, as well as lower average availability in the first quarter influenced by more scheduled outages.

Partially offsetting the year-over-year increase in Commodity Margin, Adjusted EBITDA was negatively impacted by a $41 million decrease in Adjusted EBITDA from discontinued operations associated with the sale of our Colorado plants in December 2010. In addition, although plant operating expense [3] increased by $23 million year-over-year, this increase was primarily driven by the addition of our Mid-Atlantic plants in July 2010; consistent with our focus on efficiencies, plant operating expense [3] for our legacy fleet decreased $11 million year-over-year. Sales, general and administrative expense [4] remained comparable year-over-year, with the exception of a $10 million credit related to the reversal of a bad debt allowance in the first half of 2010 that did not recur in the current period. Also contributing to the offset, as previously discussed, was a $15 million favorable adjustment in other revenue recognized during the first half of 2010 related to a major maintenance contract.

Net loss [2] increased to $367 million for the six months ended June 30, 2011, from $162 million in the prior year period. As detailed in Table 1, Net Loss, As Adjusted, was $165 million in the first half of 2011 compared to $196 million in the first half of 2010. The improvement was primarily due to the increase in Commodity Margin, as previously discussed, offset by increases in plant operating expense associated with the acquisition of our Mid-Atlantic fleet and higher major maintenance expense associated with our plant outage schedule, as well as a $10 million bad debt allowance reversal recognized in the first half of 2010 that did not recur in the first half of 2011, as previously discussed.

Table 1: Summarized Consolidated Condensed Statements of Operations

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Operating revenues	$ 1,633	$ 1,430	$ 3,132	$ 2,944
Operating expenses	(1,448)	(1,328)	(2,938)	(2,699)
(Income) loss from unconsolidated investments in power plants	2	(6)	(7)	(13)
Income from operations	183	108	201	258
Net interest expense, (gain) loss on interest rate derivatives, debt extinguishment costs, and other (income) expense	235	220	632	415
Loss before income taxes and discontinued operations	(52)	(112)	(431)	(157)
Income tax expense (benefit)	18	6	(65)	17
Loss before discontinued operations	(70)	(118)	(366)	(174)
Discontinued operations, net of tax expense	—	4	—	12
Net loss	$ (70)	$ (114)	$ (366)	$ (162)
Net income attributable to the noncontrolling interest	—	(1)	(1)	—
Net loss attributable to Calpine	$ (70)	$ (115)	$ (367)	$ (162)
Discontinued operations, net of tax expense	-	(4)	-	(12)
Debt extinguishment costs (1)	5	7	98	7
Unrealized MtM (gains) losses on derivatives (1)(2)	(50)	47	77	(62)
Other items (1) (3)	60	22	27	33
Net Loss, As Adjusted (4)	$ (55)	$ (43)	$ (165)	$ (196)

(1) Shown net of tax, assuming a 0% effective tax rate for these items.
(2) Represents unrealized mark-to-market (MtM) (gains) losses on contracts that did not qualify as hedges under the hedge accounting guidelines or qualified under the hedge accounting guidelines and the hedge accounting designation had not been elected.
(3) Other items include realized mark-to-market losses associated with the settlement of non-hedged interest rate swaps totaling $60 million and $103 million for the three and six months ended June 30, 2011, respectively, and $3 million and $14 million for the three and six months ended June 30, 2010. Other items for the six months ended June 30, 2011, also include a $(76) million federal deferred income tax benefit associated with our election to consolidate our CCFC subsidiary for tax reporting purposes. Other items for the three and six months ended June 30, 2010, also include $19 million in costs associated with the acquisition of our Mid-Atlantic fleet.
(4) See “Regulation G Reconciliations” for further discussion of Net Loss, As Adjusted.

REGIONAL SEGMENT REVIEW OF RESULTS

Table 2: Commodity Margin by Segment (in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
West	$ 236	$ 258	$ 469	$ 471
Texas	128	128	195	235
North	179	79	314	131
Southeast	59	68	113	126
Total	$ 602	$ 533	$ 1,091	$ 963

West: Commodity Margin in our West segment decreased by $22 million for the three months ended June 30, 2011, compared to the same period in 2010, primarily resulting from a decrease of $10 million in REC revenue relating to the timing of revenue recognized during the second quarter of 2010 associated with the receipt of CPUC approval of new contracts related to our Geysers assets. In addition, Commodity Margin decreased due to lower market heat rates on our off-peak open position resulting from an increase in hydroelectric generation in California which is forecast to be significantly higher in 2011 compared to 2010, and from an unscheduled outage at OMEC during the second quarter of 2011. The decrease was partially offset by higher average hedge prices for the second quarter of 2011 compared to 2010.

Commodity Margin in our West segment was comparable for the six months ended June 30, 2011 compared to the same period in 2010. During the first half of 2011, we experienced higher average hedge prices as well as positive impacts from origination activities. The increase was partially offset by lower market heat rates on our open position resulting from an increase in hydroelectric generation in California, as previously discussed, and lower Commodity Margin resulting from an unscheduled outage at OMEC during the second quarter of 2011.

Texas: Commodity Margin in our Texas segment was comparable for the three months ended June 30, 2011, compared to the same period in 2010. During the second quarter of 2011, we realized higher average hedge prices and higher market heat rates on our open position, which was largely offset by lower Commodity Margin associated with the sale of a 25% undivided interest in the assets of our Freestone power plant in December 2010.

Commodity Margin in our Texas segment decreased by $40 million for the six months ended June 30, 2011 compared to the same period in 2010. Despite an increase in average hedge prices, 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. Lower average availability in the first quarter of 2011, influenced by higher scheduled outages, as well as the aforementioned sale of an undivided interest in the assets of our Freestone power plant, also contributed to the period over period decrease in Commodity Margin.

North: Commodity Margin in our North segment increased by $100 million for the three months ended June 30, 2011, compared to the same period in 2010, primarily due to the acquisition of our Mid-Atlantic fleet, which closed on July 1, 2010.

Commodity Margin in our North segment increased by $183 million, for the six months ended June 30, 2011, compared to the same period in 2010, primarily due to the Mid-Atlantic acquisition, as previously discussed. The increase in Commodity Margin also resulted from higher realized spark spreads on open positions among our legacy power plants driven by an increase in market heat rates, and higher average hedge prices for the six months ended June 30, 2011 compared to the six months ended June 30, 2010.

Southeast: Commodity Margin in our Southeast segment decreased by $9 million for the three months ended June 30, 2011, compared to the same period in 2010 largely due to the expiration of certain hedge contracts which benefited the second quarter of 2010 as well as lower Commodity Margin that resulted from unscheduled outages that occurred during the second quarter of 2011.

Commodity Margin in our Southeast segment decreased by $13 million for the six months ended June 30, 2011 compared to the same period in 2010. The six-month results were largely impacted by the same factors that drove performance for the second quarter, as previously discussed.

LIQUIDITY AND CAPITAL RESOURCES

Table 3: Liquidity

	June 30, 2011	December 31, 2010
	(in millions)	
Cash and cash equivalents, corporate [1]	$ 846	$ 1,058
Cash and cash equivalents, non-corporate	301	269
Total cash and cash equivalents	1,147	1,327
Restricted cash	217	248
Revolving facility(ies) availability [2]	631	623
Letter of credit availability [3]	7	35
Total current liquidity availability	$ 2,002	$ 2,233

(1) Includes nil and $6 million of margin deposits held by us posted by our counterparties at June 30, 2011, and December 31, 2010, respectively.
(2) On December 10, 2010, we executed our $1.0 billion Corporate Revolving Facility, which replaced our $1.0 billion revolver under our First Lien Credit Facility. At December 31, 2010, the letters of credit issued under our First Lien Credit Facility were either replaced by letters of credit issued by the Corporate Revolving Facility or back-stopped by an irrevocable standby letter of credit issued by a third party. Our letters of credit under our Corporate Revolving Facility at December 31, 2010, include those that were back-stopped of approximately $83 million. The back-stopped letters of credit were returned and extinguished during the first quarter of 2011. The balance at December 31, 2010, includes availability under the NDH Project Debt, which was retired on March 9, 2011.
(3) Includes availability under Calpine Development Holdings, Inc.

Liquidity remained strong at over $2.0 billion as of June 30, 2011, down modestly from $2.2 billion at December 31, 2010. Cash flows provided by operating activities for the six months ended June 30, 2011, resulted in net inflows of $239 million compared to $170 million for the same period in 2010. The change in cash flows from operating activities was primarily due to income from operations, which increased by $55 million during the period after adjusting for non-cash items. In addition, cash paid for interest decreased by $70 million due to the timing of interest payments on our new bonds and term loans compared to the previously outstanding First Lien Credit Facility and project debt. These improvements were partially offset by an increase in working capital employed of $19 million, after adjusting for debt related balances that did not impact cash provided by operating activities, as well as prepayment premiums of $13 million incurred during the six months ended June 30, 2011. Cash flows from investing activities resulted in a net outflow of $421 million in the six months ended June 30, 2011, driven largely by capital expenditures, including our growth projects at Russell City, Los Esteros and York Energy Centers and our turbine upgrade program. Cash flows from financing activities resulted in a net inflow of $2 million, primarily as a result of the net impact of refinancing activities, as further discussed below.

Adjusted Recurring Free Cash Flow was $20 million for the six months ended June 30, 2011, compared to $118 million for the prior year period. Despite a $46 million increase in Adjusted EBITDA, Adjusted Recurring Free Cash Flow declined primarily as a result of a $129 million increase in major maintenance expense and capital expenditures resulting from our plant outage schedule and unscheduled outages. We remain on track with our annual maintenance program, which is reflected in our raised 2011 Adjusted Recurring Free Cash Flow guidance.

During the second quarter of 2011, we continued to improve the quality of our liquidity by securing a $360 million term loan to retire project debt associated with our Metcalf and Deer Park Energy Centers. This refinancing allowed us to migrate project debt to the corporate level, further simplifying our capital structure and alleviating cash restrictions. During the period, we also obtained an approximately $845 million credit facility to finance the construction of the 619 MW combined-cycle Russell City Energy Center, in which we own a 75% interest. The credit facility provides a construction loan that converts to a ten-year term loan when commercial operations begin.

PLANT DEVELOPMENT

York Energy Center: We acquired the York Energy Center, a 565 MW dual fuel, combined-cycle power plant under construction as part of the acquisition of our Mid-Atlantic portfolio. York Energy Center achieved COD on March 2, 2011, three months early. The York Energy Center sells power under a six-year PPA with a third party which commenced on June 1, 2011.

Russell City Energy Center: The Russell City Energy Center is under construction and continues to move forward with expected COD in 2013. 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. We are in possession of all required approvals and permits, and we closed on construction financing on June 24, 2011. The project's prevention of significant deterioration permit is currently the subject of an ongoing appeal at the U.S. Court of Appeals for the Ninth Circuit brought by Chabot-Las Positas Community College District against the EPA. Upon completion, the Russell City Energy Center is contracted to deliver its full output to PG&E under a ten-year PPA.

Los Esteros: During 2009, we and PG&E negotiated a new PPA to replace the existing California Department of Water Resources contract and facilitate the upgrade of our Los Esteros Critical Energy Facility from a 188 MW simple-cycle generation power plant to a 308 MW combined-cycle generation power plant, which will also increase the efficiency and environmental performance of the power plant by lowering the heat rate. The PPA and related agreements with PG&E have received all of the necessary approvals and licenses, which are now effective. The California Energy Commission has renewed our license and emission limits, which is final. The Bay Area Air Quality Management District issued its renewal of the Authority to Construct. We have executed contracts for all major equipment and have selected and contracted with the engineering, procurement and construction contractor. We began construction in the second quarter of 2011 and are in the process of obtaining project financing which is expected to be completed in the third quarter of 2011. We expect COD in 2013.

Turbine Upgrades: We continue to move forward with our turbine upgrade program. Through June 30, 2011, we have completed the upgrade of eight Siemens and five GE turbines and have agreed to upgrade approximately eight additional Siemens and GE turbines (and may upgrade additional turbines in the future). Our turbine upgrade program is expected to increase our generation capacity in total by approximately 275 MW. This upgrade program began in the fourth quarter of 2009 and is scheduled through 2014. The upgraded turbines have been operating with heat rates falling in line with expectations.

Geysers Assets Expansion: We continue to look to expand our production from our Geysers assets. Beginning in the fourth quarter of 2009, we conducted an exploratory drilling program, which effectively proved the commercial viability of the steam field in the northern part of our Geysers assets; however, permitting challenges have emerged that we are continuing to resolve, and we expect to receive the Sonoma County permit in the second half of 2011. We were planning to target a 2013 COD for an expansion of our Geysers assets and had been, in parallel, negotiating commercial arrangements to support that, but due to the permitting challenges, we may not meet a 2013 COD. We continue to believe our northern Geysers assets have potential for development. In the near term, we will connect the test wells to our existing power plants to capture incremental production from those wells, while continuing with the permitting process, baseline engineering work and sales efforts for an expansion.

PJM: Given our view of the potential need for new generation in the PJM region, driven by both market growth and the expected impacts of environmental regulations on older, less efficient generation within the region, we view the PJM region as a market with an attractive growth profile. In order to capitalize on this outlook, we are actively pursuing a set of development options, including projects at:

- Edge Moor (Delaware): Feasibility study under way with PJM for the addition of 300 MW of combined-cycle capacity at our existing site, leveraging existing infrastructure;
- Garrison (Delaware): Actively permitting 309 MW of new combined-cycle capacity at a development site secured by a lease option;
- Talbert (Maryland): Existing interconnect agreement for 200 MW of new simple-cycle capacity at a development site secured by a lease option;
- Powell (Maryland): Existing interconnect agreement for 300 – 500 MW of new simple-cycle capacity at a development site that we are currently in the process of purchasing; and
- Other locations that we feel provide similar opportunity to position us for growth within the region.

OPERATIONS UPDATE

Second Quarter 2011 Power Operations Achievements :

- Safety Performance:
  - First quartile lost-time incident rate of 0.36 year-to-date
- Availability Performance:
  - Achieved record second quarter fleet-wide starting reliability of over 98%
- Geothermal Generation: Provided approximately 1.5 million MWh of renewable baseload generation with 92% capacity factor
- Natural Gas-fired Generation:
  - Mankato Energy Center: Achieved 100% starting reliability and 0% forced outage factor during second quarter of 2011

Second Quarter 2011 Commercial Operations Achievements:

- Customer-oriented Growth:
  - Signed ten-year contract with Entergy Texas, Inc. to provide 485 MW of power from Carville Energy Center
  - Signed additional seasonal originated contract in the Southeast

FINANCIAL OUTLOOK

	Full Year 2011 (in millions)
Adjusted EBITDA	$ 1,700 – 1,750
Less:	
Operating lease payments	30
Major maintenance expense and capital expenditures (1)	390
Recurring cash interest, net	780
Cash taxes	15
Other	10
Adjusted Recurring Free Cash Flow	$ 475 - 525
Non-recurring interest rate swap payments (2)	175

(1) Includes projected Major Maintenance Expense of $235 million and maintenance Capital Expenditures of $155 million. Capital Expenditures exclude major construction and development projects.
(2) Interest payments related to legacy LIBOR hedges associated with floating rate First Lien Credit Facility, which has been refinanced.

As detailed above, today we are updating and tightening our 2011 guidance. We are now projecting full year Adjusted EBITDA of $1,700 million to $1,750 million and Adjusted Recurring Free Cash Flow of $475 million to $525 million. We are also reaffirming our estimates of growth capital expenditures for the year. We expect to invest $155 million, net of debt funding, in growth-related projects during the year, including our York Energy Center (now complete), our construction projects at Russell City and Los Esteros Energy Centers, and our ongoing turbine upgrade program.

INVESTOR CONFERENCE CALL AND WEBCAST

We will host a conference call to discuss our financial and operating results for the second quarter of 2011 on Friday, July 29, 2011, at 10 a.m. ET / 9 a.m. CT. A listen-only webcast of the call may be accessed through our website at www.calpine.com, or by dialing 877-874-1588 at least 10 minutes prior to the beginning of the call. An archived recording of the call will be made available for a limited time on our website. The recording also can be accessed by dialing 888-203-1112 or 719-457-0820 for international listeners and providing Confirmation Code 1100419. Presentation materials to accompany the conference call will be made available on our website on July 29, 2011.

ABOUT CALPINE

Founded in 1984, Calpine Corporation is a major U.S. power company, currently capable of delivering approximately 28,000 megawatts of clean, cost-effective, reliable and fuel-efficient power from its 92 operating plants to customers and communities in 20 U.S. states and Canada. Calpine Corporation is committed to helping meet the needs of an economy that demands more and cleaner sources of electricity. Calpine owns, leases and operates primarily low-carbon, natural gas-fired and renewable geothermal power plants. Using advanced technologies, Calpine generates power in a reliable and environmentally responsible manner for the customers and communities it serves. Please visit our website at www.calpine.com for more information.

Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, has been filed with the Securities and Exchange Commission (SEC) and may be found on the SEC's website at www.sec.gov.

FORWARD-LOOKING INFORMATION

In addition to historical information, this release contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the U.S. Securities Act of 1933, as amended, and Section 21E of the Exchange Act. Forward-looking statements may appear throughout this report, including without limitation, "Management's Discussion and Analysis." 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, fluctuations in liquidity and volatility in the energy commodities markets and our ability to hedge risks;*
- *Regulation in the markets in which we participate and our ability to effectively respond to changes in laws and regulations or the interpretation thereof including changing market rules and evolving federal, state and regional laws and regulations including those related to climate change, greenhouse gas emissions and derivative transactions;*
- *The unknown future impact on our business from the Dodd-Frank Act and the rules to be promulgated under it;*
- *Our ability to manage our liquidity needs and to comply with covenants under our First Lien Notes, Corporate Revolving Facility, Term Loan, New Term Loan, 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;*
- *Competition, including risks associated with marketing and selling power in the evolving energy markets;*
- *The expiration or 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, or acts of terrorism that may impact our power plants or the markets our power plants serve and our corporate headquarters;*
- *Disruptions in or limitations on the transportation of natural gas, fuel oil and transmission of power;*
- *Our ability to manage our customer and counterparty exposure and credit risk, including our commodity positions;*
- *Our ability to attract, motivate and retain key employees;*
- *Present and possible future claims, litigation and enforcement actions; and*
- *Other risks identified in this report and our 2010 Form 10-K.*

Given the risks and uncertainties surrounding forward-looking statements, you should not place undue reliance on these statements. Many of these factors are beyond our ability to control or predict. Our forward-looking statements speak only as of the date hereof. 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.

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions, except share and per share amounts)			
Operating revenues	$ 1,633	$ 1,430	$ 3,132	$ 2,944
Operating expenses:				
Fuel and purchased energy expense	1,000	904	2,069	1,873
Plant operating expense	261	213	499	431
Depreciation and amortization expense	131	135	262	271
Sales, general and other administrative expense	34	50	66	72
Other operating expenses	22	26	42	52
Total operating expenses	1,448	1,328	2,938	2,699
(Income) loss from unconsolidated investments in power plants	2	(6)	(7)	(13)
Income from operations	183	108	201	258
Interest expense	192	224	383	405
(Gain) loss on interest rate derivatives, net	37	(8)	146	3
Interest (income)	(2)	(4)	(5)	(6)
Debt extinguishment costs	5	7	98	7
Other (income) expense, net	3	1	10	6
Loss before income taxes and discontinued operations	(52)	(112)	(431)	(157)
Income tax expense (benefit)	18	6	(65)	17
Loss before discontinued operations	(70)	(118)	(366)	(174)
Discontinued operations, net of tax expense	—	4	—	12
Net loss	(70)	(114)	(366)	(162)
Net income attributable to the noncontrolling interest	—	(1)	(1)	—
Net loss attributable to Calpine	$ (70)	$ (115)	$ (367)	$ (162)
Basic and diluted loss per common share attributable to Calpine:				
Weighted average shares of common stock outstanding (in thousands)	486,411	486,057	486,334	485,989
Loss before discontinued operations attributable to Calpine	$ (0.14)	$ (0.25)	$ (0.75)	$ (0.35)
Discontinued operations, net of tax expense attributable to Calpine	—	0.01	—	0.02
Net loss per common share attributable to Calpine – basic and diluted	$ (0.14)	$ (0.24)	$ (0.75)	$ (0.33)

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	June 30, 2011	December 31, 2010
	(in millions, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,147	$ 1,327
Accounts receivable, net of allowance of $4 and $2	738	669
Margin deposits and other prepaid expense	170	221
Restricted cash, current	175	195
Derivative assets, current	569	725
Inventory and other current assets	285	292
Total current assets	3,084	3,429
Property, plant and equipment, net	13,033	12,978
Restricted cash, net of current portion	42	53
Investments	84	80
Long-term derivative assets	110	170
Other assets	545	546
Total assets	$ 16,898	$ 17,256
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 602	$ 514
Accrued interest payable	203	132
Debt, current portion	126	152
Derivative liabilities, current	643	718
Other current liabilities	298	273
Total current liabilities	1,872	1,789
Debt, net of current portion	10,190	10,104
Deferred income taxes, net of current	1	77
Long-term derivative liabilities	221	370
Other long-term liabilities	225	247
Total liabilities	12,509	12,587
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $.001 par value per share; 100,000,000 shares authorized; none issued and outstanding	—	—
Common stock, $.001 par value per share; 1,400,000,000 shares authorized; 446,380,252 and 444,883,356 shares issued, respectively, and 445,801,327 and 444,435,198 shares outstanding, respectively	1	1
Treasury stock, at cost, 578,925 and 448,158 shares, respectively	(7)	(5)
Additional paid-in capital	12,293	12,281
Accumulated deficit	(7,876)	(7,509)
Accumulated other comprehensive loss	(83)	(125)
Total Calpine stockholders' equity	4,328	4,643
Noncontrolling interest	61	26
Total stockholders' equity	4,389	4,669
Total liabilities and stockholders' equity	$ 16,898	$ 17,256

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
	2011	2010
	(in millions)	
Cash flows from operating activities:		
Net Loss	$ (366)	$ (162)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization expense [1]	279	298
Debt extinguishment costs	85	7
Deferred income taxes	(90)	(4)
Loss on disposal of assets	9	9
Unrealized mark-to-market activity, net	77	(62)
Income from unconsolidated investments in power plants	(7)	(13)
Return on unconsolidated investments in power plants	6	2
Stock-based compensation expense	12	12
Other	5	(1)
Change in operating assets and liabilities:		
Accounts receivable	(68)	68
Derivative instruments, net	(29)	(81)
Other assets	58	171
Accounts payable and accrued expenses	166	(91)
Liabilities related to non-hedging interest rate swaps	103	14
Other liabilities	(1)	3
Net cash provided by operating activities	239	170
Cash flows from investing activities:		
Purchases of property, plant and equipment	(341)	(97)
Cash acquired due to consolidation of OMEC	—	8
Purchases of deferred transmission credits	(8)	—
Decrease in restricted cash	30	224
Settlement of non-hedging interest rate swaps	(103)	(14)
Other	1	3
Net cash provided by (used in) investing activities	(421)	124

(Table continues)

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

	Six Months Ended June 30,	
	2011	2010
	(in millions)	
Cash flows from financing activities:		
Repayments of project financing, notes payable and other	$ (419)	$ (277)
Borrowings from project financing, notes payable and other	69	—
Repayments on NDH Project Debt	(1,283)	—
Borrowings under Term Loan and New Term Loan	1,657	—
Issuance of First Lien Notes	1,200	400
Repayments on First Lien Credit Facility	(1,187)	(430)
Capital contributions from noncontrolling interest holder	34	—
Financing costs	(67)	(15)
Refund of financing costs	—	10
Other	(2)	—
Net cash provided by (used in) financing activities	2	(312)
Net decrease in cash and cash equivalents	(180)	(18)
Cash and cash equivalents, beginning of period	1,327	989
Cash and cash equivalents, end of period	$ 1,147	$ 971
Cash paid during the period for:		
Interest, net of amounts capitalized	$ 292	$ 362
Income taxes	$ 12	$ 9
Supplemental disclosure of non-cash investing and financing activities:		
Change in capital expenditures included in accounts payable	$ 21	$ (7)

(1) Includes depreciation and amortization that is also recorded in fuel and purchased energy expense, interest expense and discontinued operations on our Consolidated Condensed Statements of Operations.

REGULATION G RECONCILIATIONS

Net Loss, As Adjusted, Commodity Margin, Adjusted EBITDA and Adjusted Recurring Free Cash Flow are non-GAAP financial measures that we use as measures of our performance. These measures should be viewed as a supplement to and not a substitute for our U.S. GAAP measures of performance.

Net Loss, As Adjusted, represents net income (loss) attributable to Calpine, adjusted for certain non-cash and non-recurring items as previously detailed in Table 1, including discontinued operations, net of tax expense, debt extinguishment costs, unrealized mark-to-market (gains) losses on derivatives, and other adjustments. Net Loss, As Adjusted, is presented because we believe it is a useful tool for assessing the operating performance of our company in the current period. Net Loss, As Adjusted, is not intended to represent net income (loss), 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.

Commodity Margin includes our power and steam revenues, sales of purchased power and natural gas, capacity revenue, revenue from renewable energy credits, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, RGGI compliance and other environmental costs and cash settlements from our marketing, hedging and optimization activities that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenues. Commodity Margin is presented because we believe it is a useful tool for assessing the performance of our core operations, and it is a key operational measure reviewed by our chief operating decision maker. 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.

Adjusted EBITDA represents earnings before interest, taxes, depreciation and amortization, adjusted for certain non-cash and non-recurring items as detailed in the following reconciliation. Adjusted EBITDA is presented because our management uses Adjusted EBITDA (i) as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends; (ii) as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations; and (iii) in communications with our Board of Directors, shareholders, creditors, analysts and investors concerning our financial performance. 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. Adjusted EBITDA is not a measure calculated in accordance with U.S. GAAP and should be viewed as a supplement to and not a substitute for our results of operations presented in accordance with U.S. GAAP. Adjusted EBITDA is not intended to represent cash flows from operations or net income (loss) as defined by U.S. GAAP as an indicator of operating performance and is not necessarily comparable to similarly titled measures reported by other companies.

Adjusted Recurring Free Cash Flow represents net income before interest, taxes, depreciation and amortization, as adjusted, less operating lease payments, major maintenance expense and maintenance capital expenditures, net cash interest, cash taxes, working capital and other adjustments. Adjusted Recurring Free Cash Flow is presented because our management uses this measure, among others, to make decisions about capital allocation. Adjusted Recurring Free Cash Flow is not intended to represent cash flows from operations as defined by U.S. GAAP as an indicator of operating performance and is not necessarily comparable to similarly titled measures reported by other companies.

Commodity Margin Reconciliation

The following table reconciles our Commodity Margin to its U.S. GAAP results for the three months ended June 30, 2011 and 2010:

	Three Months Ended June 30, 2011 (in millions)					
	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin	$ 236	$ 128	$ 179	$ 59	$ —	$ 602
Add: Mark-to-market commodity activity, net and other revenue [1]	11	27	—	—	(9)	29
Less:						
Plant operating expense	116	63	47	41	(6)	261
Depreciation and amortization expense	42	35	33	22	(1)	131
Sales, general and other administrative expense	8	13	6	6	1	34
Other operating expenses [2]	11	3	9	2	(5)	20
Loss from unconsolidated investments in power plants	—	—	2	—	—	2
Income (loss) from operations	$ 70	$ 41	$ 82	$ (12)	$ 2	$ 183

	Three Months Ended June 30, 2010 (in millions)					
	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin	$ 258	$ 128	$ 79	$ 68	$ —	$ 533
Add: Mark-to-market commodity activity, net and other revenue [1]	10	(10)	3	(9)	(6)	(12)
Less:						
Plant operating expense	88	78	23	31	(7)	213
Depreciation and amortization expense	50	40	19	27	(1)	135
Sales, general and other administrative expense	11	16	22	2	(1)	50
Other operating expenses [2]	12	(5)	7	(1)	8	21
(Income) from unconsolidated investments in power plants	—	—	(6)	—	—	(6)
Income (loss) from operations	$ 107	$ (11)	$ 17	$ —	$ (5)	$ 108

Commodity Margin Reconciliation (continued)

The following table reconciles our Commodity Margin to its U.S. GAAP results for the six months ended June 30, 2011 and 2010:

	Six Months Ended June 30, 2011 (in millions)					
	West	**Texas**	**North**	**Southeast**	**Consolidation And Elimination**	**Total**
Commodity Margin	$ 469	$ 195	$ 314	$ 113	$ —	$ 1,091
Add: Mark-to-market commodity activity, net and other revenue [1]	16	(33)	4	(4)	(15)	(32)
Less:						
Plant operating expense	203	143	92	74	(13)	499
Depreciation and amortization expense	88	65	66	45	(2)	262
Sales, general and other administrative expense	19	23	12	11	1	66
Other operating expenses [2]	19	3	16	3	(3)	38
(Income) from unconsolidated investments in power plants	—	—	(7)	—	—	(7)
Income (loss) from operations	$ 156	$ (72)	$ 139	$ (24)	$ 2	$ 201

	Six months Ended June 30, 2010 (in millions)					
	West	**Texas**	**North**	**Southeast**	**Consolidation And Elimination**	**Total**
Commodity Margin	$ 471	$ 235	$ 131	$ 126	$ —	$ 963
Add: Mark-to-market commodity activity, net and other revenue [1]	18	86	—	13	(14)	103
Less:						
Plant operating expense	178	162	45	59	(13)	431
Depreciation and amortization expense	103	76	39	56	(3)	271
Sales, general and other administrative expense	26	16	25	6	(1)	72
Other operating expenses [2]	29	2	15	2	(1)	47
(Income) from unconsolidated investments in power plants	—	—	(13)	—	—	(13)
Income from operations	$ 153	$ 65	$ 20	$ 16	$ 4	$ 258

(1) Mark-to-market commodity activity represents the unrealized portion of our mark-to-market activity, net, included in operating revenues and fuel and purchased energy expense on our Consolidated Condensed Statements of Operations.

(2) Excludes $2 million and $5 million of RGGI compliance costs and other environmental costs for the three months ended June 30, 2011 and 2010, respectively, and $4 million and $5 million for the six months ended June 30, 2011 and 2010, respectively, which are included as a component of Commodity Margin.

Consolidated Adjusted EBITDA Reconciliation

In the following table, we have reconciled our Adjusted EBITDA and Adjusted Recurring Free Cash Flow to our Net Loss for the three and six months ended June 30, 2011 and 2010, as reported under U.S. GAAP.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Net loss attributable to Calpine	$ (70)	$ (115)	$ (367)	$ (162)
Net income attributable to noncontrolling interest	—	1	1	—
Discontinued operations, net of tax expense	—	(4)	—	(12)
Income tax expense (benefit)	18	6	(65)	17
Other (income) expense and debt extinguishment costs, net	8	8	108	13
(Gain) loss on interest rate derivatives, net	37	(8)	146	3
Interest expense, net	190	220	378	399
Income from operations	$ 183	$ 108	$ 201	$ 258
Add:				
Adjustments to reconcile income from operations to Adjusted EBITDA:				
Depreciation and amortization expense, excluding deferred financing costs (1)	131	136	263	273
Major maintenance expense	76	43	136	98
Operating lease expense	9	11	17	22
Unrealized (gain) loss on commodity derivative mark-to-market activity	(26)	31	39	(81)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments (2)	13	8	21	15
Stock-based compensation expense	7	6	12	12
Non-cash loss on dispositions of assets	4	(1)	9	5
Conectiv acquisition-related costs	—	19	—	19
Other	9	—	11	1
Adjusted EBITDA from continuing operations	406	361	709	622
Adjusted EBITDA from discontinued operations	—	20	—	41
Total Adjusted EBITDA	$ 406	$ 381	$ 709	$ 663
Less:				
Lease payments	9	11	17	22
Major maintenance expense and capital expenditures (3)	152	43	263	134
Cash interest (4)	195	190	393	382
Cash taxes	6	6	10	8
Other	3	—	6	(1)
Adjusted Recurring Free Cash Flow (5)	$ 41	$ 131	$ 20	$ 118

(1) Depreciation and amortization expense in the income from operations calculation on our Consolidated Condensed Statements of Operations excludes amortization of other assets.
(2) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include unrealized gains (losses) on mark-to-market activity of nil for the three and six months ended June 30, 2011 and 2010.
(3) Includes $80 million and $138 million in major maintenance expense for the three and six months ended June 30, 2011, respectively, and $72 million and $125 million in maintenance capital expenditures for the three and six months ended June 30, 2011, respectively. Includes $47 million and $105 million in major maintenance expense for the three and six months ended June 30, 2010, respectively, and $(3) million and $29 million in maintenance capital expenditures for the three and six months ended June 30, 2010, respectively.
(4) Includes commitment, letter of credit and other bank fees from both consolidated and unconsolidated investments, net of capitalized interest and interest income.
(5) Excludes decrease in working capital of $45 million and $145 million for the three and six months ended June 30, 2011, respectively, and increase in working capital of $140 million and $80 million for the three and six months ended June 30, 2010, respectively. Adjusted Recurring Free Cash Flow, as reported, excludes changes in working capital, such that it is calculated on the same basis as our guidance.

Consolidated Adjusted EBITDA Reconciliation (continued)

In the following table, we have reconciled our Adjusted EBITDA to our Commodity Margin, both of which are non-GAAP measures, for the three and six months ended June 30, 2011 and 2010. Reconciliations for both Adjusted EBITDA and Commodity Margin to comparable U.S. GAAP measures are provided above.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Commodity Margin	$ 602	$ 533	$ 1,091	$ 963
Other revenue	3	19	7	22
Plant operating expense (1)	(176)	(168)	(346)	(323)
Sales, general and administrative expense (2)	(27)	(27)	(55)	(46)
Other operating expense (3)	(10)	(10)	(19)	(23)
Adjusted EBITDA from unconsolidated investments in power plants (4)	10	14	27	28
Adjusted EBITDA from discontinued operations (5)	—	20	—	41
Other	4	—	4	1
Adjusted EBITDA	$ 406	$ 381	$ 709	$ 663

(1) Shown net of major maintenance expense, stock-based compensation expense, non-cash loss on dispositions of assets and acquisition-related costs.
(2) Shown net of stock-based compensation expense and acquisition-related costs.
(3) Excludes $2 million and $5 million of RGGI compliance costs and other environmental costs for the three months ended June 30, 2011 and 2010, respectively, and $4 million and $5 million for the six months ended June 30, 2011 and 2010, respectively, which are included as a component of Commodity Margin.
(4) Amount is comprised of income from unconsolidated investments in power plants, as well as adjustments to reflect Adjusted EBITDA from unconsolidated investments.
(5) Represents Adjusted EBITDA from Blue Spruce and Rocky Mountain power plants, which were sold in December 2010.

Adjusted EBITDA and Adjusted Recurring Free Cash Flow Reconciliation for Guidance

Full Year 2011 Range:	Low	High
	(in millions)	
GAAP Net Income (Loss)	$ (150)	$ (100)
Plus:		
(Gain) loss on interest rate derivatives, net	146	146
Debt extinguishment costs	98	98
Interest expense, net of interest income	760	760
Depreciation and amortization expense	560	560
Major maintenance expense	230	230
Operating lease expense	35	35
Other (1)	21	21
Adjusted EBITDA	$ 1,700	$ 1,750
Less:		
Operating lease payments	30	30
Major maintenance expense and maintenance capital expenditures (2)	390	390
Recurring cash interest, net (3)	780	780
Cash taxes	15	15
Other	10	10
Adjusted Recurring Free Cash Flow	$ 475	$ 525
Non-recurring interest rate swap payments (4)	175	175

(1) Other includes stock-based compensation expense, adjustments to reflect Adjusted EBITDA from unconsolidated investments, income tax expense and other items.
(2) Includes projected major maintenance expense of $235 million and maintenance capital expenditures of $155 million. Capital expenditures exclude major construction and development projects.
(3) Includes fees for letters of credit, net of interest income.
(4) Interest payments related to legacy LIBOR hedges associated with floating rate First Lien Credit Facility, which has been refinanced.

CASH FLOW ACTIVITIES

The following table summarizes our cash flow activities for the six months ended June 30, 2011 and 2010:

	Six Months Ended June 30,	
	2011	2010
	(in millions)	
Beginning cash and cash equivalents	$ 1,327	$ 989
Net cash provided by (used in):		
Operating activities	239	170
Investing activities	(421)	124
Financing activities	2	(312)
Net increase (decrease) in cash and cash equivalents	(180)	(18)
Ending cash and cash equivalents	$ 1,147	$ 971

OPERATING PERFORMANCE METRICS

The table below shows the operating performance metrics for continuing operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Total MWh generated (in thousands [1])	19,394	19,246	37,521	39,604
West	3,454	5,485	9,649	14,702
Texas	7,867	8,243	13,186	14,885
Southeast	4,286	4,222	8,571	7,647
North	3,787	1,296	6,115	2,370
Average availability	84.8%	87.7%	86.8%	89.0%
West	75.9%	88.4%	83.9%	90.8%
Texas	89.1%	88.4%	84.3%	85.5%
Southeast	85.3%	87.1%	89.8%	91.4%
North	88.4%	85.4%	89.7%	88.9%
Average capacity factor, excluding peakers	37.6%	42.5%	37.2%	44.3%
West	25.3%	40.2%	35.7%	54.2%
Texas	51.6%	52.4%	43.5%	47.8%
Southeast	36.0%	35.3%	37.0%	32.8%
North	34.6%	31.3%	29.6%	28.8%
Steam adjusted heat rate (mmbtu/kWh)	7,451	7,306	7,411	7,266
West	7,755	7,359	7,495	7,298
Texas	7,204	7,222	7,224	7,169
Southeast	7,322	7,319	7,310	7,305
North	7,985	7,648	7,888	7,613

(1) Excludes generation from unconsolidated power plants, plants owned but not operated and discontinued operations.