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NRG Energy Inc

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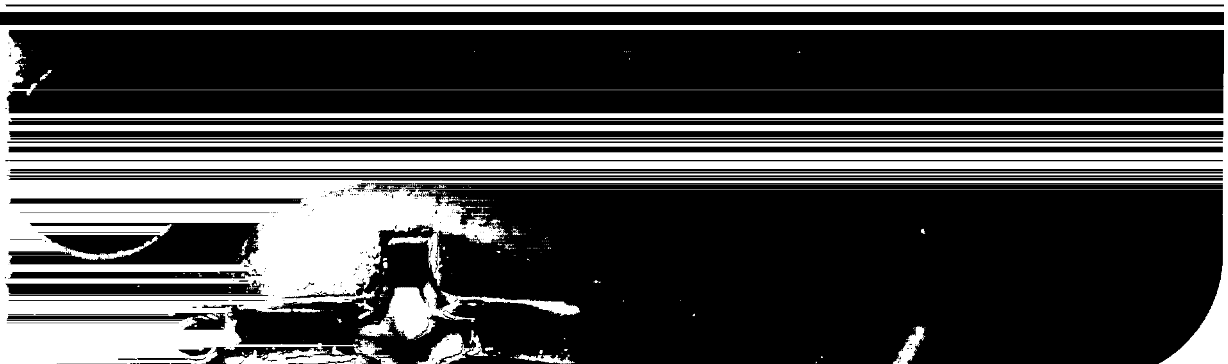
P.E. 12/31/04

NRG 2004 ANNUAL REPORT AND FORM-10K



Face Value

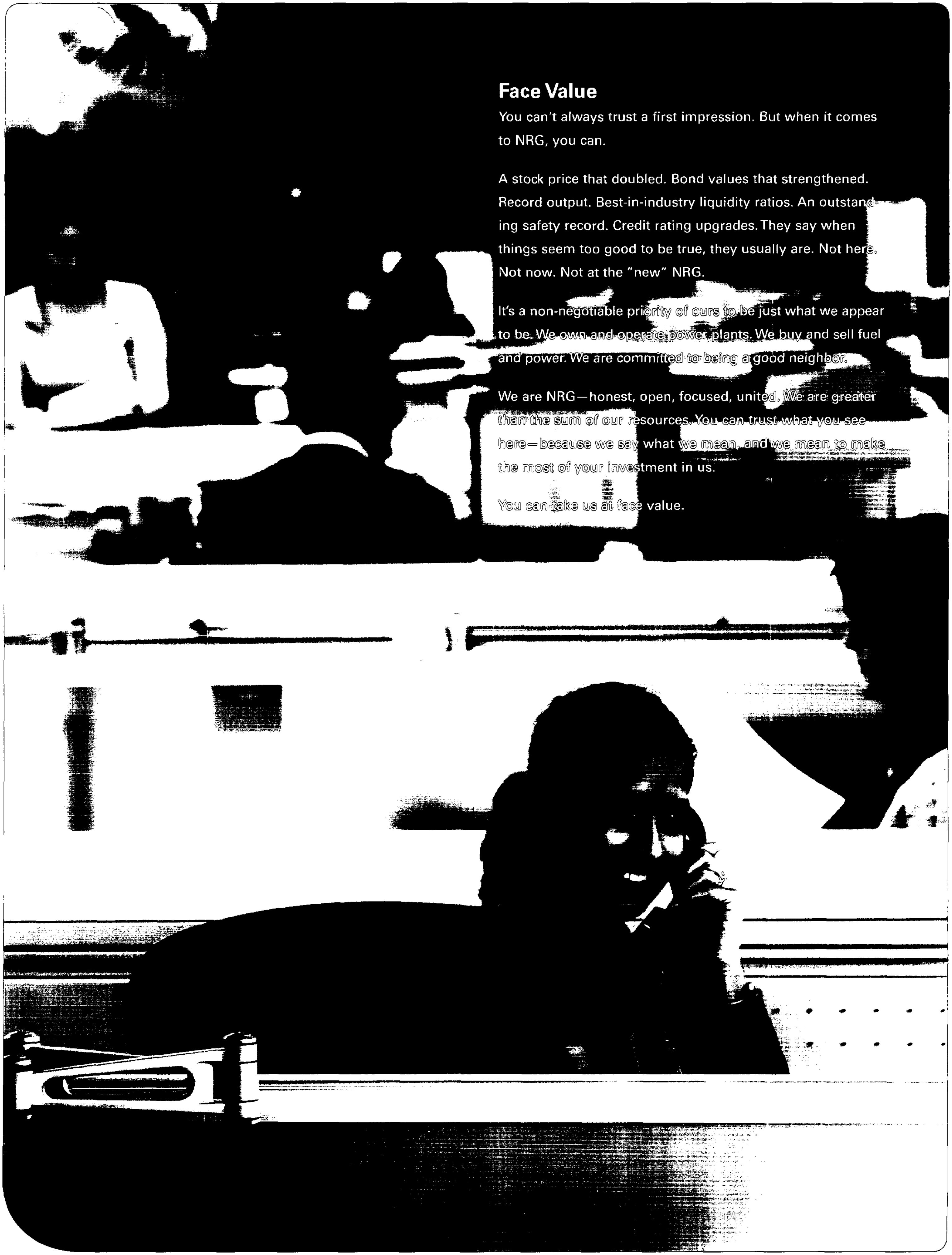
You can't always trust a first impression. But when it comes to NRG, you can.

A stock price that doubled. Bond values that strengthened. Record output. Best-in-industry liquidity ratios. An outstanding safety record. Credit rating upgrades. They say when things seem too good to be true, they usually are. Not here. Not now. Not at the "new" NRG.

It's a non-negotiable priority of ours to be just what we appear to be. We own and operate power plants. We buy and sell fuel and power. We are committed to being a good neighbor.

We are NRG—honest, open, focused, united. We are greater than the sum of our resources. You can trust what you see here—because we say what we mean, and we mean to make the most of your investment in us.

You can take us at face value.



Fellow Shareholders

If it seems incredible that, in such a short time after emerging from Chapter 11, our Company has been restored to full financial health, it is. And it's a testament to the hard work and smart choices of everyone from our plant operating staff to our managers to our leadership team.

But don't take my word for it—look at our financials, our operations and our people. You can take us at face value.

At Face Value: Our Financial Results

For 2004—our first year as the new NRG—we achieved $976 million of adjusted EBITDA on $2.4 billion of total operating revenues. Considering that we are carrying only $3.8 billion of debt—without any significant principal repayments for the next five years—plus approximately $1.1 billion of cash, it's not necessary for me to hype our financial standing. NRG, quite simply, is in an excellent position to take advantage of the opportunities available to us.

I've stressed from the outset that we're going to manage this business for cash and, in 2004, that's what we did—generating $559 million of net cash flow and reducing our net debt-to-capital ratio to approximately 49 percent.

Prudent balance sheet management is a fundamental principle of the new NRG and you can accept my pledge at face value: it's a principle from which we will not deviate.

At Face Value: Our Operating Performance

Even with a mild summer in our biggest region, the northeastern United States, our operating results were strong in 2004. Remarkably, we achieved such strong results even while transitioning a substantial portion of our coal-fired plants to cleaner-burning western coal—a tremendous accomplishment, made possible by the hard work, dedication and careful coordination of many people across NRG.

Overall, 2004 was a positive year for our three major contributors to gross margin:

Energy sales: The step up in our energy-sale proceeds continues to demonstrate the earnings strength of our coal-fired plants in a high-gas-price environment.

Contract revenues: Several of our power plants, particularly in the South Central region, generated revenue through long-term power sales agreements. While revenues from these contracts are generally considered more predictable than our energy sales, to be paid on these contracts our plants must perform. During 2004, they did just that, with our flagship Big Cajun II plant leading the way with a record year of generation output.

Capacity payments: Many of our plants are well situated within load pockets and, as such, make critical contributions to system stability. To ensure that our plants are available to provide their services when needed, a variety of capacity payment mechanisms exists in our various markets. We received a healthy contribution to our gross margin both from locational capacity payments in New York and RMR (reliability-must-run) arrangements in Connecticut and California.

At Face Value: Our Strategy

Our value proposition is based on the interrelationship of two NRG strengths: 1) our portfolio of geographically coherent, fuel-diverse power-generating facilities, and 2) our trading and marketing expertise, which optimizes the value of those facilities around the clock.

Our strategy is straightforward: we constantly seek to improve both sides of that value equation.

On the power plant side, we do this in several ways. First, we focus relentlessly on improving fleet reliability, implementing best practices, securing the benefits of scale in procurement and training our people. On top of this, we reinvest in our existing plants—extending life, improving heat rate, reducing emissions, increasing capacity and adding units—when such improvements bring direct and quantifiable economic benefit to NRG.

We also seek to enhance our portfolio through the acquisition of complementary plants—plants that not only represent a good long-term investment in their own right, but that also have the potential to increase the value of our existing plants by being operated and traded as part of a larger, integrated portfolio. As the new NRG has not actually acquired any plants, I want to assure you that we will assess our opportunities to do so in a very disciplined manner.

On the trading and marketing side of the value equation, we use these functions to optimize the return on our assets and mitigate market risks. Because both our output (electricity) and our input (coal, gas and oil) markets are highly cyclical and volatile, and in some cases relatively illiquid, we need to execute intelligently and expeditiously in this area and stay closely synchronized with what is happening at our plants. We do this well, and we will enhance our ability to do it better and more broadly in the future.

At Face Value: Our Move

A year ago, as we worked feverishly to establish the new NRG, we spent a lot of time looking at our assets, our people and our customers. Before long, we realized it would be easier to serve our stakeholders if we were closer to them. Physically.

So, in 2004 we moved NRG headquarters to New Jersey, right in the middle of our key northeastern business. It's just a move, yes, but NRG's new, open offices demonstrate our commitment to direct, honest and complete communication.

Our new headquarters in New Jersey is a lifesized metaphor for the new way of working at NRG. No dividing walls, no offices—just an open floor plan with a single, shared workspace. It may not be the right environment for many companies, but it is the right one for the new NRG. As one professional at NRG said to me, "At the old NRG, you had to go out of your way to communicate with your colleagues: at the new NRG, you have to go out of your way *not* to communicate with each other."

At Face Value: Our Core Values

As we move forward, we recognize that there is never room for complacency in the competitive power sector. As such, it is no coincidence that the acronym which encapsulates all of our core values is STRIVE:

Safety—Our safety record is better than the industry average, and we will never rest in our quest for zero injuries (and if we reach that goal, we still will not rest, because safety always comes first).

Teamwork—We are lean, and the demands of our business vary significantly from time to time. We depend on a "lend a hand" culture.

Respect—With opportunity comes responsibility, and NRG staff members bear substantial individual responsibility at all levels and at all locations around the Company. We embrace the chance to demonstrate respect for each other, our communities and our environment.

Integrity—We accept nothing less than honest and open communication and behavior. You can take each and every one of us at face value.

Value Creation—We work hard at NRG, but we recognize that how hard we work is only as important as what we achieve. We stay focused on the value that is created by what we do.

Exemplary Leadership—We will go furthest when everyone in this Company—at all levels—is a leader; and the first principle of leadership is leading by personal example.

At Face Value: Our Promise to You

We've slimmed down the Company. We've focused the business. We've improved our balance sheet. And we've achieved all of this through the hard work of everyone at NRG—the talented people who were here when we arrived, together with those we have brought on board.

Bottom line? Those who invested their time and trust in us through NRG stock or bonds at the time of our emergence from Chapter 11 have made a healthy profit. You may be one of them, and I assure you—and those of you who have invested in us more recently—that we will continue to make prudent, intelligent and focused choices. We are dedicated to repeating the success we achieved in 2004.

All of us at NRG appreciate your investment in us. We will do everything possible to increase our face value for you.

Sincerely,

David Crane
President and Chief Executive Officer
March 30, 2005

A Message from the Chairman

Dear Shareholder,

It is my pleasure to serve as nonexecutive Chairman of the NRG Board of Directors, and I'm pleased to have been part of such a successful year.

In the report that follows you will find the operating results for 2004. Management has done an outstanding job in creating value for you, the shareholder. During 2004, your Board focused on the Company's strategic direction, financial performance and corporate governance practices. Because your Board is committed to ensuring that what you see is reality, my letter will focus primarily on corporate governance, a topic of crucial importance to us, NRG's management team and its shareholders.

Good corporate governance starts at the top. The stockholders elect the Board and it is our job to oversee and to evaluate management—particularly the CEO—and to approve the strategic direction of your Company. While management executes day-to-day operations, my role as nonexecutive Chairman is to lead your Board in carrying out its responsibilities and to serve as the main contact with management. Together, the Board and management set the tone at the top of the Company, with an emphasis on open communication, transparent accounting and ethical conduct.

Adhering to the highest standards of corporate governance, all NRG directors, except for the CEO, are independent. They are not employees and they do not have other business relations with NRG. These independent directors bring a diverse base of knowledge and backgrounds, as well as business judgment, to your Company, and they do not hesitate to speak their minds and ask the tough questions.

Many of the governance practices require extensive, detailed and time-consuming work. To effectively accomplish this, your Board has three standing committees: Audit, Compensation and Governance and Nominating. During 2004, these committees met a total of 38 times, which allowed for full Board meetings to be more productive and focused on the business of NRG.

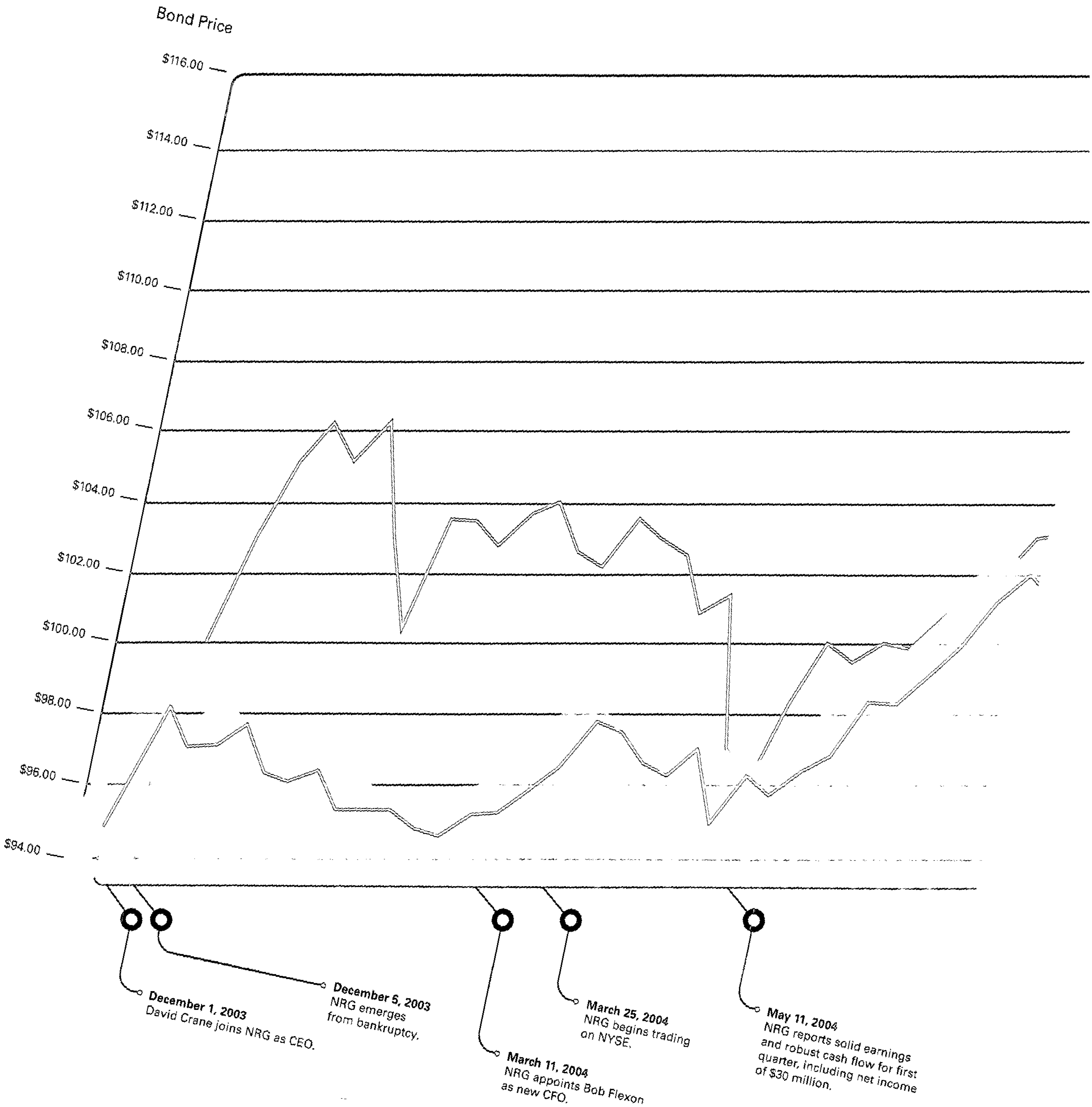
At www.nrgenergy.com/investor/corpgov.htm you can find the Board-approved corporate governance guidelines, the NRG Code of Conduct and the committee charters.

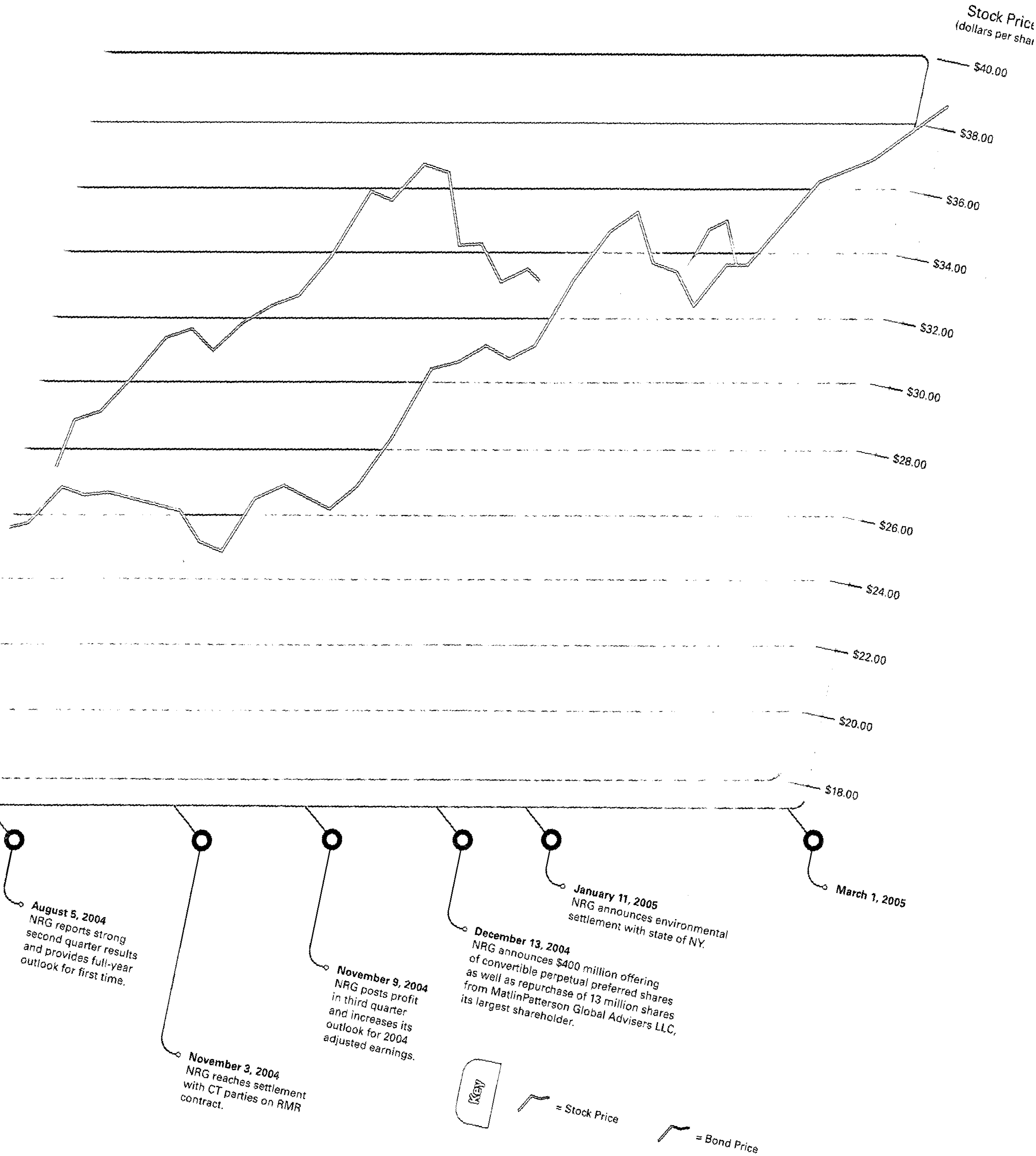
Your directors take their responsibilities very seriously, and we would be glad to receive any thoughts or suggestions you have.

Sincerely,

Howard Cosgrove
Chairman

ue means: Delivering results that speak for themselves





Stock Price
(dollars per shar
$40.00
$38.00
$36.00
$34.00
$32.00
$30.00
$28.00
$26.00
$24.00
$22.00
$20.00
$18.00
August 5, 2004
NRG reports strong second quarter results and provides full-year outlook for first time.
November 3, 2004
NRG reaches settlement with CT parties on RMR contract.
November 9, 2004
NRG posts profit in third quarter and increases its outlook for 2004 adjusted earnings.
December 13, 2004
NRG announces $400 million offering of convertible perpetual preferred shares as well as repurchase of 13 million shares from MatlinPatterson Global Advisers LLC, its largest shareholder.
January 11, 2005
NRG announces environmental settlement with state of NY.
March 1, 2005
Key
= Stock Price
= Bond Price

Face Value means: Fuel and geographically diverse assets

North American Locations

Northeast

1. **Arthur Kill**, Staten Island, NY ⊜
2. **Astoria Gas Turbines**, Queens, NY ⊜ ◆
3. **Conemaugh**, New Florence, PA □
4. **Connecticut Remote Turbines**, Various, CT ◆
5. **Devon**, Milford, CT ⊜ ▽ ◆
6. **Dunkirk**, Dunkirk, NY □
7. **Huntley**, Tonawanda, NY □
8. **Indian River**, Millsboro, DE □ ▽
9. **Keystone**, Shelocta, PA □
10. **Middletown**, Middletown, CT ▽ ⊜ ◆
11. **Montville**, Uncasville, CT ▽ ⊜ ◇
12. **Norwalk Harbor**, South Norwalk, CT ▽
13. **Oswego**, Oswego, NY ▽ ⊜
14. **Somerset Power**, Somerset, MA □ ▽ ◆
15. **Vienna**, Vienna, MD ▽

South Central

1. **Bayou Cove**, Jennings, LA ⊜
2. **Big Cajun I**, New Roads, LA ⊜
3. **Big Cajun I Peakers**, New Roads, LA ⊜
4. **Big Cajun II**, New Roads, LA □ (sub-bituminous)
5. **Sterlington**, Sterlington, LA ⊜

Western

1. **Chowchilla II**, Chowcilla, CA ○
2. **El Segundo**, El Segundo, CA ⊜
3. **Encina Power Station**, Carlsbad, CA ⊜ ▽
4. **Red Bluff**, Red Bluff, CA ○
5. **Saguaro**, Henderson, NV ⊜ ▽
6. **San Diego Turbines**, San Diego, CA ⊜ ◇

Other North America

1. **Audrain**, Vandalia, MO ○
2. **Cadillac**, Cadillac, MI D
3. **Dover Energy**, Dover, DE ○ □
4. **Ilion**, Ilion, NY ○ ▽
5. **James River**, Hopewell, VA □
6. **Power Smith Cogeneration**, Oklahoma City, OK ○
7. **Rockford I**, Rockford, IL ○
8. **Rockford II**, Rockford, IL ○
9. **Rocky Road**, East Dundee, IL ○
10. **Turners Falls (idle)**, Turners Falls, MA □

★ **NRG Headquarters**, Princeton, NJ

Symbol Key				
	⊜ **Natural Gas**	▽ **Oil**	D **Wood**	△ **Hydro**
	◆ **Jet**	□ **Coal**	◇ **Diesel**	○ **Gas**

This map of locations, as of 4/01/05, is not a comprehensive listing of NRG's assets.

International Locations

Latin America

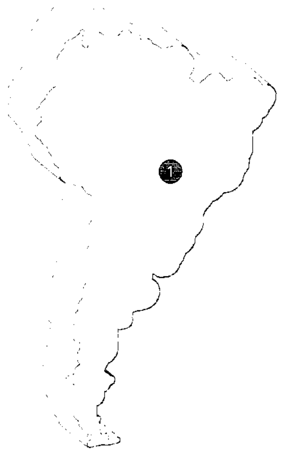
1. **Itiquira Energetica,** Rondonopolis, Brazil △

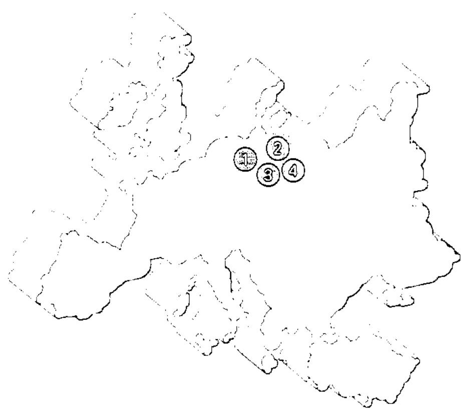
Europe

1. **Schkopau**, Halle, Germany □
2. **MIBRAG-Wahlitz**, Wahlitz, Germany □
3. **MIBRAG-Deuben,** Deuben, Germany □
4. **MIBRAG-Mumsdorf**, Mumsdorf, Germany □

Australia

1. **Gladstone Power Station,** Gladstone, Queensland, Australia □
2. **Flinders,** Port Augusta, Australia □





Financial Data ($ thousands except per share data)

Income Statement:	**2004**	**Dec 6 - 31, 2003**	**Jan 1 -Dec 5, 2003**	**2002**
Operating revenues	$2,361,424	$138,490	$1,798,387	$1,938,293
Operating income (loss)	$399,115	$16,162	$3,273,910	($2,383,092)
Net income	$185,617	$11,025	$2,766,445	($3,464,282)

Cash Flow:	**2004**	**Dec 6 - 31, 2003**	**Jan 1 -Dec 5, 2003**	**2002**
Cash flow from operations	$643,993	($588,875)	$238,509	$430,042
Capital expenditures	$114,360	$10,560	$113,502	$1,439,733
Cash and cash equivalents at end of period	$1,110,045	$551,223	$395,982	$360,860

Common Share Data	**2004**	**Dec 6 - 31, 2003**
Net earnings per share - basic	$1.86	$0.11
Net earnings per share - diluted	$1.85	$0.11
Weighted average common shares outstanding - basic	99,616	100,000
Weighted average common shares outstanding - diluted	100,371	100,060

Capitalization:	**Dec 31, 2004**	**Dec 31, 2003**
Total debt, including capital leases	$3,807,196	$4,216,541
Common equity	$2,285,805	$2,437,256
Preferred equity	$406,359	
Total capital	$6,499,360	$6,653,797

Ratios:		
Total debt/capital	59%	63%
Cash and cash equivalents/per diluted share	$11.06	$5.51

Operating Statistics	**2004**	**2003**
(NRG's net share)		
U.S. electric power generation (MWh)*	28,956,124	
Total worldwide capacity (MW)	15,400	18,200

* Excludes Conemaugh and Keystone

Name: Glenn Lange **Title:** Manager of Operations, Huntley Generating Station **Years at Huntley:** 27

Responsibilities: Oversees the safe operation of the plant, trains employees, schedules repairs, solves problems

Works most closely with: Huntley's plant manager, station shift supervisor and power marketing's New York desk

Most fulfilling task: Facing challenges and resolving problems to maximize revenue for NRG

What "face value" means to Glenn: We accomplish more when we work together.

Clear the air.

It all began with one lofty but critical objective at our New York plants: dramatically reduce sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions.

The search was on, and it led our Huntley and Dunkirk plants to a distant place—a vast, rugged stretch of rolling hills and high plains in northeastern Wyoming called the Powder River Basin. Bordering these 11 million acres of big-sky country are the Bighorn Mountains and the Black Hills. Beneath is a veritable gold mine of one of the world's cleanest coals, PRB (Powder River Basin) coal.

The unlikely cross-country partnership of New York plants and Wyoming coal has produced some powerful results for NRG and for our neighbors.

First, the air: since implementing PRB coal into operations at our Huntley and Dunkirk plants, we've been able to cut SO_2 emission rates by 50 percent, thanks to Wyoming coal's extremely low sulfur content (up to 99 percent lower than eastern coal).

In addition, the combustion characteristics of PRB coal, combined with enhancements we've made to combustion control, have enabled us to reduce thermal NOx emission rates by nearly 40 percent.

But what about the cost? When we began this quest, no PRB coal was being shipped in commercial quantities as far as New York. As it takes about 30 to 40 percent more PRB coal than eastern coal to produce the same amount of energy, could this be a truly cost-effective solution?

Surprisingly, yes. As we ran the numbers, it became immediately apparent that there was a secondary benefit to converting to PRB coal: it is more abundantly available and less costly to mine than eastern coal.

Even factoring in the transportation, additional volume and equipment upgrades that PRB coal requires, its total cost is less than we were spending on eastern coal. In effect, our plants have been able to meet and to exceed their emissions-reduction goals, while spending less money for fuel than before converting to PRB coal.

In other words, environmental and financial responsibility can go hand-in-hand.

With over 50,000 square miles of deep coal beds—including the thickest coal seam in the United States, at 250 feet deep—Wyoming's Powder River Basin is a rich, long-term resource for NRG.

The transition to PRB coal has been a significant undertaking, and the real credit, as always, goes to our people. Working with PRB coal has required us to develop new operating processes, creatively adjust existing equipment and change things that have worked fine for years. In the next year or so, we will further enhance our technology to make PRB-based operations even smoother, but in the meantime, our operators are working hard to help NRG reap the benefits of PRB coal.

We are exceptionally pleased with the results that PRB coal has enabled us to achieve. It has been worth every bit of effort—because at NRG, we go the extra mile to bring you responsible, profitable results.

And now, so does our coal.

Face Value means: To trade power and fuels for profits.

Seeing is believing.

It's no accident that the first thing you see through the glass wall of the NRG lobby—and at the center of the entire office—is our power marketing operation.

Every molecule of NRG fuel and power is managed by the people behind the glass—sometimes years in advance, sometimes an hour before it's used. Here is where we buy, sell and trade every commodity of value to NRG: over 12 million tons of coal, four million barrels of oil and 26 billion cubic feet of gas purchased in 2004, as well as 32.7 billion kilowatt hours of power generated by our plants last year. Here we also manage logistics for over 2,500 rail cars, schedule natural gas movements across 10 interstate pipelines, move barges across six inland waterways and balance emissions credits across 35 facilities. Unlike a regulated utility, NRG must use its commercial acumen to compete successfully in these markets in order to generate profits and value for the Company.

Transparency is a key to our power marketing success. Our power marketing group is openly accessible to everyone in NRG headquarters, and it is fully integrated with our plant staff and all other functional areas.

At its most basic level, power marketing does two things for NRG: manages risk and maximizes margins. This team of 50 ensures that we take just enough risk with our commodity positions to be profitable, while maximizing the revenue from everything we sell. For a merchant generator, commodity-price risk is inextricably linked to operational risk. If facilities perform as expected, we make the margins we projected. If they don't, we risk losing profits.

The more we are familiar with how our facilities can perform, the less risk there is that we will over-sell, under-buy or vice versa. Success requires close coordination with all of the operations groups across the NRG fleet of generating facilities.

So how does that look? It looks like our new office—people working together, blending each individual part of NRG into a profitable whole.

It looks like traders constantly talking with the plants to find out how much power they are capable of producing—today, next week, next month, next year, even two years down the road. The answers change daily, so the collaboration is constant.

It looks like power marketing and our regional staff working together to create customized structured products for our customers.

And it means monitoring and measuring everything we do through our risk control and credit groups to ensure that we maintain appropriate levels of risk, and that we always report accurately and openly to investors.

Our traders know our plants and how they operate in the markets. They comb the market for pricing anomalies and fundamental shifts, and then use that knowledge to capture value.

The principle is simple: know the market, understand our assets' capabilities, quantify our risk and time our execution to maximize profits.

In many ways, power marketing can be seen as a hub of NRG, but our traders' success depends on constant interaction with every functional area of our Company. Making them a more visible part of the organization shows the importance we place on our markets, our customers and on involving everyone in this effort.

Name: Jim Dauer **Title:** Director, Natural Gas, NRG Power Marketing **Years at NRG:** 4

Responsibilities: Optimizes the value of NRG's assets by ensuring the delivery of low-cost fuel to gas-fired plants and capitalizes on natural gas storage and transportation opportunities

Works most closely with: His gas scheduler, the hourly traders, other portfolio directors and our gas plant managers

Most interesting part of the day: Morning trading

What "face value" means to Jim: Intrinsic value. It's the first building block of value creation.

Name: Gary Elender • **Title:** Environmental Manager, NRG South Central Region • **Years at South Central Region:** 25

Responsibilities: Helps NRG meet and exceed environmental regulations so we can build and operate power plants

Works most closely with: NRG plant environmental engineers, regional staff and corporate environmental business team

Likes most about his job: Working with a great variety of people, including regulatory agencies, to serve the environment

What "face value" means to Gary: What you see is what you get.

The grass is greener.

These days, white-tailed deer and wild turkeys dart in and out of the trees along Bayou Pierre in northwest Louisiana, as though they've always been there. Migratory waterfowl fill the bayou as if nothing were new.

But, in fact, a large section of this bottomland hardwood forest—a section called the Oxbow Reforestation Project—was not even here a few short years ago.

As part of our commitment to the world around us, NRG owns and manages this budding, new, 2,000-acre forest, about 35 miles south of Shreveport, Louisiana.

The project constitutes one of the largest single reforestation efforts on private land in the southeastern United States to be supported by the U.S. Fish and Wildlife Service (USFWS).

But the size of the project only hints at its true value.

When it comes to our neighbors, the real benefit is that we have increased fish and wildlife habitat, as well as water and soil quality, by restoring increasingly scarce bottomland hardwood forest. And when it comes to NRG, we have provided a return to a more natural habitat—a more responsible use of our Louisiana land.

An added benefit to the environment as a whole is that the trees provide a natural "carbon sink," helping to offset manmade greenhouse gases.

Before the first plantings began, the Oxbow site was marginal farmland, purchased with the intent to construct a power plant on it. When plans changed, the land was reforested in partnership with the USFWS.

Five years, 5,000 pounds of seed, 419,850 seedlings, 16 species of native trees, four water-control structures, two low dikes and 40 wood duck nests later, the land was transformed back into its natural state. The site now includes 60 acres of shallow-water wetlands and nearly 2,000 acres of bottomland hardwood forest.

Today, migratory waterfowl, shorebirds, raptors, deer, raccoons and many small-game species live and thrive within the Oxbow site. The return to a more natural environment has improved the water quality in surrounding streams and bayous and has reduced sedimentation in area waterways. And our neighbors on every side enjoy more wildlife encounters and more quality educational resources as local schools visit the site to learn about wetland restoration and wildlife management.

Next time you're in Louisiana, driving south on Interstate 49, look to your left, just after exit 162, and come face-to-face with a living example of yet another NRG value: the Oxbow Reforestation Project.

Board of Directors

Howard Cosgrove, Nonexecutive Chairman
Retired Chairman and Chief Executive Officer of Conectiv and its predecessor, Delmarva Power and Light; Chairman of the Board of Trustees at the University of Delaware; Director for Henlopen Mutual Fund

John Chlebowski
Retired President and Chief Executive Officer of Lakeshore Operating Partners, LLC; Director for Laidlaw International Inc. and SpectraSite, Inc.

Lawrence Coben
Chairman and Chief Executive Officer of Tremisis Energy Acquisition Corporation; Director for Prisma Energy

Stephen Cropper
Retired President and Chief Executive Officer of Williams Energy Services; Director for Berry Petroleum Company, Sun Logistics Partners LP, Energy Transfer Partners, LP and Rental Car Finance Corporation

Anne Schaumburg
Retired Managing Director, Global Energy Group of Credit Suisse First Boston

Herbert Tate
Corporate Vice President, Regulatory Strategy of NiSource, Inc.; Director for IDT Capital and IDT Spectrum

Thomas Weidemeyer
Retired Senior Vice President and Chief Operating Officer of United Parcel Service, Inc.; Director for Goodyear Tire & Rubber Co. and Waste Management, Inc.

Walter Young
Retired Chairman, Chief Executive Officer and President of Champion Enterprises, Inc.

*David Crane is also a Director

Audit Committee Members
John Chlebowski (Chair)
Howard Cosgrove
Walter Young

Compensation Committee Members
Lawrence Coben (Chair)
Thomas Weidemeyer
Walter Young

Governance and Nominating Committee Members
Stephen Cropper (Chair)
John Chlebowski
Herbert Tate

Executive Officers

David Crane
President and Chief Executive Officer*

Robert Flexon
Executive Vice President and Chief Financial Officer

John Brewster
Executive Vice President, International Operations and President, South Central Region

Scott Davido
Executive Vice President and President, Northeast Region

James Ingoldsby
Vice President, Controller

Christine Jacobs
Vice President, Plant Operations

Timothy O'Brien
Vice President, General Counsel and Secretary

Ershel Redd Jr.
Executive Vice President, Commercial Operations and President, Western Region

George Schaefer
Vice President, Treasurer

Stock Transfer Agent and Registrar
Wells Fargo Bank, N.A.
P.O. Box 64854
St. Paul, Minnesota 55164-0864
800.468.9716 or 651.450.4064
www.wellsfargo.com/shareownerservices

Stock Listing
NRG's common stock is listed on the New York Stock Exchange under the ticker symbol NRG.

Financial Information
NRG's Annual Report, Proxy Statement, Form 10-K and other filings are available at www.nrgenergy.com under the Investors section.

NRG Energy, Inc. 2004 Form 10-K

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

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year ended December 31, 2004.

☐ **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. 001-15891

NRG Energy, Inc.
(Exact name of Registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**41-1724239** *(I.R.S. Employer Identification No.)*
211 Carnegie Center **Princeton, New Jersey** *(Address of principal executive offices)*	**08540** *(Zip Code)*

(609) 524-4500
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
None	None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, par value $0.01 per share

Indicate by check mark whether the Registrant (1) has filed all reports 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 ☑ 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 the 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 an accelerated filer as defined by Rule 12b-2 of the Act. Yes ☑ No ☐

As of the last business day of the most recently completed second fiscal quarter, the aggregate market value of the common stock of the registrant held by non-affiliates was approximately $1,943,806,466.

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 ☑ No ☐

Indicate the number of shares outstanding of each of the registrant's classes of common stock as of the latest practicable date.

Class	Outstanding at March 28, 2005
Common Stock, par value $0.01 per share	87,045,104

Documents Incorporated by Reference:
Portions of the Proxy Statement for the 2005 Annual Meeting of Stockholders

NRG ENERGY, INC. AND SUBSIDIARIES

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PART I

Item 1 — *Business*

General

NRG Energy, Inc., or "NRG Energy", the "Company", "we", "our", or "us" is a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities, the transacting in and trading of fuel and transportation services and the marketing and trading of energy, capacity and related products in the United States and internationally. We have a diverse portfolio of electric generation facilities in terms of geography, fuel type and dispatch levels. Our principal domestic generation assets consist of a diversified mix of natural gas-, coal- and oil-fired facilities, representing approximately 40%, 31% and 29% of our total domestic generation capacity, respectively. In addition, 23% of our domestic generating facilities have dual- or multiple-fuel capacity, which may allow plants to dispatch with the lowest cost fuel option.

We seek to maximize operating income through the generation of energy, marketing and trading of energy, capacity and ancillary services into spot, intermediate and long-term markets and the effective transacting in and trading of fuel supplies and transportation-related services. We perform our own power marketing (except with respect to our West Coast Power and Rocky Road affiliates), which is focused on maximizing the value of our North American and Australian assets through the pursuit of asset-focused power and fuel marketing and trading activities in the spot, intermediate and long-term markets. Our principal objectives are the management and mitigation of commodity market risk, the reduction of cash flow volatility over time, the realization of the full market value of the asset base, and adding incremental value by using market knowledge to effectively trade positions associated with our asset portfolio. Additionally, we work with markets, independent system operators and regulators to promote market designs that provide adequate long-term compensation for existing generation assets and to attract the investment required to meet future generation needs.

As of December 31, 2004, we owned interests in 52 power projects in five countries having an aggregate net generation capacity of approximately 15,400 MW. Approximately 7,900 MW of our capacity consisted of merchant power plants in the Northeast region of the United States. Certain of these assets are located in transmission constrained areas, including approximately 1,400 MW of "in-city" New York City generation capacity and approximately 750 MW of southwest Connecticut generation capacity. We also own approximately 2,500 MW of capacity in the South Central region of the United States, with approximately 1,900 MW of that capacity supported by long-term power purchase agreements.

As of December 31, 2004, our assets in the West Coast region of the United States consisted of approximately 1,300 MW of capacity with the majority of such capacity owned via our 50% interest in West Coast Power LLC, or West Coast Power. Our assets in the West Coast region were supported by a power purchase agreement with the California Department of Water Resources that expired on December 31, 2004. One-year term reliability must-run, or RMR, agreements with the California Independent System Operator, or Cal ISO, for approximately 568 MW in the San Diego area have been renewed for 2005. On January 1, 2005, a new RMR agreement for the 670 MW gross capacity of the West Coast Power El Segundo generating facility became effective. In January 2005, that generating facility entered into a tolling agreement for its entire gross generating capacity of 670 MW commencing May 1, 2005 and extending through December 31, 2005. During the term of this agreement, the purchaser will be entitled to primary energy dispatch right for the facility's generating capacity. The agreement is subject to the amendment of the El Segundo RMR agreement to switch to RMR Condition I and to otherwise allow the purchaser to exercise its primary dispatch rights under this agreement while preserving Cal ISO's ability to call on the El Segundo facility as a reliability resource under the RMR agreement, if necessary. Approximately 265 MW of capacity at the Long Beach generating facility was retired January 1, 2005.

We own approximately 1,600 MW of net generating capacity in other regions of the U.S. We also own interests in plants having a net generation capacity of approximately 2,100 MW in various international markets, including Australia, Europe and Brazil. We operate substantially all of our generating assets, including the West Coast Power plants.

We were incorporated as a Delaware corporation on May 29, 1992. In March 2004, our common stock was listed on the New York Stock Exchange under the symbol "NRG". Our headquarters and principal executive offices are located at 211 Carnegie Center, Princeton, New Jersey 08540. Our telephone number is (609) 524-4500. The address of our website is www.nrgenergy.com. Our recent annual reports, quarterly reports, current reports and other periodic filings are available free of charge through our website. Our Corporate Governance Guidelines and the charters of our Audit, Compensation and Governance and Nominating Committees are also available on our website at www.nrgenergy.com/investor/corpgov.htm. These charters are available in print to any shareholder who requests them.

Strategy

We are a significant owner and operator of a diverse portfolio of electric generation facilities. We are focused on owning, operating and maximizing the value of our generation assets in our core regions, which are the Northeast, South Central and West Coast regions of the United States, as well as Australia. Our two principal objectives are: (i) to maximize the operating performance of our entire portfolio, and (ii) to protect and enhance the market value of our physical and contractual assets through the execution of asset-based risk management, marketing and trading strategies within well-defined risk and liquidity guidelines.

To achieve our principal objectives, we intend to pursue the following strategies, among others:

- Develop the assets in our core regions into integrated businesses well suited to serve the requirements of the load-serving entities in our core markets;
- Reinvest our capital in our existing assets for reasons of repowering, expansion, environmental remediation, operating efficiency, reliability programs, greater fuel optionality, greater merit order diversity, enhanced portfolio effect or alternative use, among others; and
- Where consistent with our "core region" strategy, pursue selective acquisitions to complement the assets and portfolios in our core regions.

From time to time we may also consider and undertake other merger and acquisition transactions that are consistent with our strategy. We continue to market our interest in our remaining non-core assets. Thereafter, we have no current plans to market actively any of our core assets, although our intention to maximize over time the value of all of our assets could lead to additional asset sales.

Competition

Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. Many of our large competitors are facing restructuring, bankruptcy or liquidation. Many U.S. markets have a glut of generation capacity. New sources of capital have entered the industry, including well-capitalized financial players seeking to acquire assets at distressed prices. Regulatory bodies, including the Federal Energy Regulatory Commission, or FERC, regional independent system operators, state public utility commissions and other regulatory participants are considering significant changes to the structure of certain wholesale utility markets.

Many companies in the regulated utility industry, with which the wholesale power industry is closely linked, are also restructuring or reviewing their strategies. Several of those companies are discontinuing their unregulated activities, seeking to divest their unregulated subsidiaries or attempting to have their regulated subsidiaries acquire assets out of their or other companies' unregulated subsidiaries. This may lead to increased competition between the regulated utilities and the unregulated power producers within certain markets.

Competitive Strengths

We believe that we benefit from the following competitive strengths:

Plant Diversity. Our generation fleet in core regional markets includes plants dispatched as baseload generation, on an intermediate basis and during peak periods. Approximately 4,300 MWs of domestic baseload capacity provide stability of cash flows, while 5,500 MWs of domestic peaking capacity give us significant upside optionality. Our generation facilities include a diversified fuel mix of natural gas, coal and oil. A significant percentage of our core domestic portfolio, approximately 31%, is fueled by coal, which is a distinct advantage at a time of historically high natural gas prices. We believe that our Huntley, Dunkirk, Big Cajun II and Indian River coal-fired facilities will continue, for the foreseeable future, to have competitive advantages in terms of their marginal cost of production relative to the gas-fired plants with which they compete. In addition, a significant portion of our non-coal domestic generation facilities have dual or multiple fuel capability, which allows most of these plants to dispatch with the lowest cost fuel option. The volatility in oil and gas prices versus the stability of low-sulfur western coal prices creates opportunities for us because of our ability to use low-sulfur coal in certain of our plants.

Locational Advantages. Owning multiple power plants in a particular market provides greater dispatch flexibility and increases power marketing and trading opportunities. We have achieved this goal to a certain extent in the Northeast (New York, New England Power Pool, or NEPOOL, and Pennsylvania, Jersey, Maryland Interconnection, or PJM) and South Central (Entergy) markets.

Transmission constraints and other market factors give certain of our power plants locational advantages over the competition. For example, the Astoria and Arthur Kill plants serve the New York City market. Competitors outside the city limits are at a disadvantage because transmission constraints restrict the importation of power into New York City, providing an advantage to "in-city" generation physically located within city limits. Construction of new power plants in New York City is limited because of the difficulties in finding sites for new plants, obtaining the necessary permits and arranging fuel delivery. In California, our facilities are located in the Los Angeles and San Diego load basins where, similar to New York City, transmission constraints restrict the import of power from remotely located plants.

In some locations, a facility's advantage is enhanced by the potential for repowering or site expansion or alternative use. Certain Connecticut facilities, for example, have attractive locations in transmission-constrained areas in southern Connecticut. The El Segundo plant located in the west Los Angeles load basin is well positioned to serve the needs of that region well into the future. Our California facilities utilize ocean water cooling, which gives them competitive advantages, especially during water shortages in California, and provides a competitive advantage in the potential siting of desalination projects or for other alternative uses. We are working to preserve our options to expand or repower these facilities when economically justifiable.

Risk Mitigation. As a wholesale generator, we are subject to the risks associated with volatility in fuel and power prices. We seek to mitigate these risks by managing a portfolio of contractual relationships for power supply, fuel needs and transportation services. We reduce spot price volatility exposure via mid- and long-term contractual arrangements when these markets economically justify such transactions. We plan to trade around the contractual commitments consistent with our market view in an effort to produce enhanced value from market volatility.

Improved Financial Position. As part of our reorganization (discussed below), we eliminated approximately $5.2 billion of corporate level bank and bond debt and approximately $1.3 billion of additional claims and additional disputes. Since January 1, 2004, we have successfully sold select non-core assets and eliminated approximately $989.9 million of consolidated debt related to those assets. We continued managing our balance sheet throughout 2004 with the tack-on bond offering in January and the refinancing of our credit facility in December.

Reorganization

We were formed in 1992 as the non-utility subsidiary of Northern States Power Company, or NSP, which was itself merged into New Century Energies, Inc. to form Xcel Energy, Inc., or Xcel Energy, in 2000. While owned by NSP and later by Xcel Energy, we pursued an aggressive high growth strategy focused on power plant acquisitions, high leverage and aggressive development, including site development and turbine orders. In 2002, a number of factors, most notably the aggressive prices paid by us for our acquisitions of turbines, development projects and plants, combined with the overall downturn in the power generation industry, triggered a series of credit rating downgrades which, in turn, precipitated a severe liquidity crisis at the Company. From May 14 to December 23, 2003, we and a number of our subsidiaries undertook a comprehensive reorganization and restructuring under chapter 11 of the United States Bankruptcy Code. With the exception of one subsidiary that remains in bankruptcy to effect its liquidation, all NRG entities had emerged from chapter 11 as of December 31, 2004.

As part of our reorganization, Xcel Energy relinquished its ownership interest in us, and we became an independent public company. We no longer have any material affiliation or relationship with Xcel Energy. As part of the reorganization, we eliminated approximately $5.2 billion of corporate level bank and bond debt and approximately $1.3 billion of additional claims and disputes by distributing a combination of equity and $1.04 billion in cash to our unsecured creditors.

As part of our restructuring, on December 23, 2003, we used the proceeds of a new $1.25 billion offering of 8% second priority senior secured notes due 2013, and borrowings under a new $1.45 billion secured credit facility, to retire approximately $1.7 billion of project-level debt. In January 2004, we used proceeds of a tack-on bond offering of the same notes to repay $503.5 million of the outstanding borrowings under the secured credit facility.

In 2004, we completed our post-confirmation bankruptcy initiatives, including the liquidation of the chapter 11 subsidiaries deemed to be of no value to NRG Energy (LSP-Nelson Energy LLC and NRG Nelson Turbines LLC); the collection and distribution to creditors of amounts owing by our pre-bankruptcy parent company, Xcel Energy, Inc., under the plan of reorganization and related documents; and the settlement of several large disputed claims. We are still litigating or seeking to settle a number of unresolved disputed claims, for which we believe we have established an adequate disputed claims reserve pursuant to the NRG plan of reorganization. In all other respects, the reorganization process was completed in 2004.

On December 24, 2004, we entered into an amendment and restatement of our $1.45 billion seven-year secured credit facility, recasting it as a $950 million seven-year secured credit facility with more favorable covenants and interest rates, scheduled to expire in December 2011. On December 27, 2004, we completed the issuance of $420 million of perpetual convertible preferred stock, and used the proceeds to redeem $375 million of our 8% second priority senior secured notes on February 4, 2005. In January 2005 and in March 2005, we purchased $25 million and $15.8 million, respectively, of the notes.

Fresh Start Reporting

As a result of our emergence from bankruptcy, we adopted Fresh Start Reporting, or Fresh Start. Under Fresh Start, our confirmed enterprise value was allocated to our assets and liabilities based on their respective fair values. See Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operation — Reorganization and Emergence from Bankruptcy for additional information. 2004 was our first complete year following the adoption of Fresh Start.

Performance Metrics

The following table contains a summary of our North American power generation revenues from majority-owned subsidiaries for the year 2004:

Region	Energy Revenues	Capacity Revenues	Alternative Energy Revenues	O&M Fees	Other Revenues***	Total Revenues
			(In thousands)			
Northeast	$ 853,454	$264,624	$ 49	$ —	$133,026	$1,251,153
South Central	219,112	183,483	—	—	15,550	418,145
West Coast*	9,276	(3,709)	—	(2)	(3,096)	2,469
Other	27,816	84,097	1,748	186	(8,203)	105,644
Total North America Power Generation**	$1,109,658	$528,495	$1,797	$184	$137,277	$1,777,411

* Consists of our wholly-owned subsidiary, NEO California LLC. Does not include revenues which were produced by assets in which we have a 50% equity interest, primarily West Coast Power, and are reported under the equity method of accounting.

** For additional information — see Item 15 — Note 23 of the Consolidated Financial Statements for our consolidated revenues by segment disclosures.

*** Includes miscellaneous revenues from the sale of natural gas, recovery of incurred costs under reliability must-run agreements, revenues received under leasing arrangements, revenues from maintenance, revenues from the sale of ancillary services and revenues from entering into certain financial transactions, offset by contract amortization.

In understanding our business, we believe that certain performance metrics are particularly important. These are industry statistics defined by the North American Electric Reliability Council and are more fully described below:

Annual Equivalent Availability Factor, or EAF: is the total available hours a unit is available in a year minus the sum of all partial outage events in a year converted to equivalent hours (EH), where EH is partial megawatts lost divided by unit net available capacity times hours of each event, and the net of these hours is divided by hours in a year to achieve EAF in percent.

Average gross heat rate: We calculate the average heat rate for our fossil-fired power plants by dividing (a) fuel consumed in Btus by (b) KWh generated. The resultant heat rate is a measure of fuel efficiency.

Net Capacity Factor: Net actual generation divided by net maximum capacity for the period hours.

The table below presents the North American power generation performance metrics for owned assets discussed above for the year ended December 31, 2004.

Region	Net Owned Capacity (MW)	Net Generation (MWh)	Annual Equivalent Availability Factor	Average Gross Heat Rate Btu/KWh	Net Capacity Factor
Northeast*	7,884	13,205,017	85.6%	10,174	19.8%
South Central	2,469	10,470,786	92.1%	9,965	52.9%
West Coast**	1,315	2,354,668	80.0%	10,121	20.4%
Other North America	1,591	2,925,653	96.3%	N/A	12.0%

* Net Generation and the other metrics do not include Keystone and Conemaugh.

** Includes 50% of the generation owned through our West Coast Power partnership.

The table below presents the Australian power generation performance metrics discussed above for the year ended December 31, 2004.

Region	Net Owned Capacity (MW)	Net Generation (MWh)	Annual Equivalent Availability Factor	Average Gross Heat Rate Btu/KWh	Net Capacity Factor
Flinders Northern Power Station	520	3,924,196	93.2%	11,400	93.1%
Flinders Playford Power Station	240	365,642	46.0%	16,300	18.9%
Gladstone*	630	3,065,044	83.2%	9,600	55.4%

* Includes 37.5% of the generation owned through our Gladstone partnership.

Power Generation

Northeast Region

Facilities. As of December 31, 2004, we owned 7,884 MW of net generation capacity in the Northeast region of the United States, primarily in New York, Connecticut and Delaware. These generation facilities are diversified in terms of dispatch level (base-load, intermediate and peaking), fuel type (coal, natural gas and oil) and customers.

The Northeast region's power generation assets as of December 31, 2004 are summarized in the table below.

Name and Location of Facility	Power Market	Net Owned Capacity (MW)	NRG's Percentage Ownership Interest	Fuel Type
Oswego, New York	NYISO	1,700	100%	Oil/Gas
Huntley, New York	NYISO	760	100%	Coal
Dunkirk, New York	NYISO	600	100%	Coal
Arthur Kill, New York	NYISO	842	100%	Gas/Oil
Astoria Gas Turbines, New York	NYISO	600	100%	Gas/Oil
Somerset, Massachusetts	ISO-NE	136	100%	Coal/Oil
Middletown, Connecticut	ISO-NE	786	100%	Oil/Gas/Jet Fuel
Montville, Connecticut	ISO-NE	498	100%	Oil/Gas/Diesel
Devon, Connecticut	ISO-NE	401	100%	Gas/Oil/Jet Fuel
Norwalk Harbor, Connecticut	ISO-NE	353	100%	Oil
Connecticut Jet Power, Connecticut	ISO-NE	127	100%	Jet Fuel
Indian River, Delaware	PJM	784	100%	Coal/Oil
Vienna, Maryland	PJM	170	100%	Oil
Conemaugh, Pennsylvania	PJM	64	4%	Coal/Oil
Keystone, Pennsylvania	PJM	63	4%	Coal/Oil

Market Framework. Our largest asset base is located in the Northeast region. This asset base is comprised of investments in generation facilities primarily located in the physical control areas of the New York Independent System Operator, or NYISO, the ISO New England, Inc., or ISO-NE, and the Pennsylvania, Jersey, Maryland Interconnection, or PJM.

Although each of the three northeast ISOs and their respective energy markets are functionally, administratively and operationally independent, they all follow, to a certain extent, the FERC-endorsed model for Standard Market Design, or SMD. The physical power deliveries in these markets are financially settled by Locational Marginal Prices, or LMPs, which reflect the value of energy at a specific location at the specific time it is delivered. This value is determined by an ISO- administered auction process, which evaluates and selects the least costly supplier offers or 'bids' to fill the specific locational requirement. The ISO-sponsored LMP energy marketplaces consist of two separate and characteristically distinct settlement time frames. The first is a security-constrained, financially firm, "Day Ahead" unit commitment market. The second is a security-constrained, financially settled, "Real-time" dispatch and balancing market. In addition to energy delivery, the ISOs manage secondary markets for installed capacity, ancillary services and financial transmission rights.

Market Developments. ISO-NE and NEPOOL operate a centralized energy market with "Day-Ahead" and "Real-time" energy markets. On August 23, 2004, ISO-NE filed its proposal for locational installed capacity, or LICAP, with FERC, which will decide the issue in a litigated proceeding before an administrative law judge. Under the proposal, separate capacity markets would be created for distinct areas of New England, including southwest Connecticut. While we view this proposal as a positive development, as it is currently proposed it would not permit us to recover all of our fixed costs. In response, we have submitted testimony which includes an alternative proposal. FERC's goal is to make a decision on the precise terms of the NEPOOL LICAP market in the fall of 2005, to be effective January 1, 2006.

On January 27, 2005, FERC approved the settlement of various reliability must-run, or RMR, agreements between some of our Connecticut generation and ISO-NE. Under the settlement, we will receive monthly payments for the Devon 11-14, Montville and Middletown facilities until December 31, 2005, the day before the expected implementation date for LICAP. The settlement also requires the payment of third party maintenance expenses by NEPOOL participants incurred by Devon 11-14, Middletown, Montville and Norwalk Harbor and are capped at $30 million for the period April 1, 2004 through December 31, 2005. The settlement also approves prior RMR agreements involving Devon 7 and 8, both of which are on deactivated reserves.

The NYISO operates an energy market that is structurally the same as the New England energy markets. In April 2003, NYISO implemented a demand curve in its capacity market and scarcity pricing improvements in its energy market. The New York demand curve eliminated the previous market structure's tendency to price capacity at either its cap (deficiency rate) or near zero. FERC had previously approved the demand curve, but on December 19, 2003, the Electricity Consumers Resource Council appealed the FERC decision to the United States Court of Appeals for the District of Columbia Circuit. On December 3, 2004, NRG Energy and other suppliers filed a brief in opposition. An adverse decision by the Court of Appeals could require the elimination of the demand curve for the capacity market, and would negatively impact the development of LICAP in New England and PJM in addition to New York.

On January 7, 2005, NYISO filed proposed LICAP demand curves for the following capacity years: 2005-06, 2006-07 and 2007-08. Under the NYISO proposal, the LICAP price for New York City generation would be $126 per KW-year for the capacity year 2006-07. On January 28, 2005, we filed a protest at FERC asserting the LICAP price for this period should be at least $140 per KW-year.

Our New York City generation is presently subject to price mitigation in the installed capacity market. When the capacity market is tight, the price we receive is limited by the mitigation price. However when the New York City capacity market is not tight, such as during the winter season, the proposed demand curve price levels should increase our revenues from capacity sales.

On January 25, 2005, FERC issued an order approving the PJM proposal to increase the compensation for generators which are located in load pockets and are mitigated at least 80% of their running time. Specifically, when a generator would be subject to mitigation, the generator would have the option of recovering its variable cost plus $40 or a negotiated rate with PJM, based on the facility's going forward costs. If the generator declines both options, it could file for an alternative rate with FERC. FERC also substantially revised the exemption of facilities built after 1996 from the energy price capping mitigation rule. Several of our facilities are presently mitigated 80% of the time and, therefore, are impacted by the change.

South Central Region

Facilities. As of December 31, 2004, we owned 2,469 MW of net generating capacity in the South Central region of the United States. The South Central region's generating assets consist primarily of our power generation facilities in New Roads, Louisiana, referred to as the Cajun Facilities, and the Sterlington and Bayou Cove generating facilities.

Our portfolio of plants in Louisiana comprises the third largest generator in the Southeastern Electric Reliability Council/Entergy, or SERC-Entergy region. Our primary assets are the Cajun Facilities, which are primarily coal-fired assets supported by long-term power purchase agreements with regional cooperatives.

The South Central region's power generation assets as of December 31, 2004 are summarized in the table below.

Name and Location of Facility	Power Market	Net Owned Capacity (MW)	NRG's Percentage Ownership Interest	Fuel Type
Big Cajun II, Louisiana*	SERC-Entergy	1,489	86%	Coal
Big Cajun I, Louisiana	SERC-Entergy	458	100%	Gas/Oil
Bayou Cove, Louisiana	SERC-Entergy	320	100%	Gas
Sterlington, Louisiana	SERC-Entergy	202	100%	Gas

* We own 100% of Units 1 and 2 and 58% of Unit 3.

Market Framework. Our South Central region's assets are located within the franchise territory of Entergy, a vertically-integrated utility. Entergy performs the scheduling, reserve and reliability functions that are administered by ISOs in certain other regions of the United States and Canada. We operate a North American Electric Reliability Council, or NERC, certified-control area within the Entergy franchise territory, which is comprised of our generating assets and our cooperatives' customer loads. In the South Central region, including Entergy's franchise territory, the energy market is not a centralized market and it does not have an independent system operator as is found in the northeast markets. All power sales and purchases are consummated bilaterally between individual counter-parties, and physically delivered either within or across the physical control areas of the transmission owners. Transacting counter-parties are required to reserve and purchase transmission services from the intervening transmission owners at their FERC-approved tariff rates. Included with these transmission services are the reserve and ancillary costs. Energy prices in the South Central region are determined and agreed to in bilateral negotiations between representatives of the transacting counter-parties, using market information gleaned by the individual marketing agents arranging the transactions.

Market Developments. We have long-term "all requirements" contracts with 11 Louisiana distribution cooperatives, serving approximately 350,000 retail customers, and long-term contracts with the Municipal Energy Agency of Mississippi, South Mississippi Electric Power Association and Southwestern Electric Power Company. With limited exceptions, the all-requirements nature of certain of the power supply agreements between Louisiana Generating and its cooperative customers requires Louisiana Generating to serve future expansion of those cooperative loads at existing contract rates. Additionally, at times of maximum demand, our generating facilities do not produce enough power to serve their customers, and we purchase power in the market to make up the shortfall.

Entergy has filed an Independent Coordinator of Transmission, or ICT, proposal at FERC and with the public service commissions of the states of Louisiana, Mississippi and Arkansas. Entergy states that this proposal will achieve greater oversight of its transmission system operation and provide greater efficiency for providing and pricing transmission service. On March 22, 2005, FERC approved the ICT proposal for a two-year period, subject to certain conditions.

On December 17, 2004, FERC ordered that an investigation and evidentiary hearing be held to determine whether Entergy is providing access to its transmission system on a short-term basis and in a just and reasonable manner. On March 22, 2005, FERC suspended the hearing until Entergy indicates whether it will accept the FERC's conditional approval of its ICT proposal. On March 25, 2005, FERC permitted Entergy's proposal regarding reserving 2,900 MWs of import capacity on its transmission system for emergency purposes to go into effect subject to refund. The case was set for hearing, which was then suspended pending settlement discussions.

In December 2004, we entered into a long-term coal transport agreement with the Burlington Northern and Santa Fe Railway Company and affiliates of American Commercial Lines LLC to deliver low sulfur coal to our Big Cajun II facility in New Roads, Louisiana beginning April 1, 2005. In December 2004, we also entered into coal purchase contracts extending through 2007. In March 2005, we entered into an agreement to purchase 23.75 tons of coal over a period of four years and nine months from Buckskin Mining Company, or Buckskin. The coal will be sourced from Buckskin's mine in the Powder River Basin, Wyoming, and will be used primarily in NRG Energy's coal-burning generation plants in the South Central region.

In August 2004, we entered into a contract to purchase 1,540 aluminum railcars from Johnston America Corporation to be used for the transportation of low sulfur coal from Wyoming to NRG Energy's coal burning generating plants, including the Cajun Facilities. On February 18, 2005, we entered into a ten-year operating lease agreement with GE Railcar Services Corporation, or GE, for the lease of 1,500 railcars and delivery commenced in February 2005. We have assigned certain of our rights and obligations for 1,500 railcars under the purchase agreement with Johnston America to GE. Accordingly, the railcars which we lease from GE under the arrangement described above will be purchased by GE from Johnston America in lieu of our purchase of those railcars.

West Coast Region

Facilities. As of December 31, 2004, we owned 1,315 MW of net generating capacity in the West Coast region, primarily in California and Nevada. Our West Coast generation assets consist primarily of a 50% interest in West Coast Power LLC, or West Coast Power. Effective January 1, 2005, the Long Beach Generating Station was permanently retired, reducing our net generating capacity by 265 MW, to 1,050 MW. The ultimate disposition of the Long Beach plant and property has yet to be determined. However, site demolition and remediation costs, if required, are expected to approximate the market value of the property. The Company has been negotiating a sale of the Saguaro plant and closing is expected to take place sometime during 2005.

In May 1999 we formed West Coast Power, along with Dynegy, Inc., to serve as the holding company for a portfolio of operating companies that own generation assets in Southern California in the California Independent System Operator, or Cal ISO, market. This portfolio currently consists of the El Segundo Generating Station, the Encina Generating Station and 13 combustion turbines in the San Diego area. Dynegy provides power marketing and fuel procurement services to West Coast Power, and we provide operations and management services. On December 23, 2004, California Energy Commission, or CEC, approved our application for a permit to repower the existing El Segundo site and replace retired units 1 and 2 with 630 MW of new generation. On January 19, 2005, the CEC voted unanimously to reconsider its December 23, 2004 decision to certify the repowering project. The reconsideration hearing took place on February 2, 2005 and the permit was approved by unanimous vote of the CEC. The reconsideration extended the 30-day period in which parties may petition for rehearing or seek judicial review to March 4, 2005. A petition seeking review of the CEC final order was filed with the California Supreme Court on March 14, 2005. We believe this filing to be untimely.

Our West Coast Power assets were supported by a power purchase agreement with the California Department of Water Resources that expired on December 31, 2004. We do not anticipate that we can replace that contract with one that has similar or more attractive terms and conditions. One-year term RMR contracts with Cal ISO for 576 MW of net owned capacity in the San Diego area have been renewed for 2005. On January 1, 2005, a new RMR agreement for the 670 MW gross capacity of the West Coast Power El Segundo generating facility became effective. In January 2005, that generating facility entered into a tolling agreement for its entire gross generating capacity of 670 MW commencing May 1, 2005 and extending through

December 31, 2005. During the term of this agreement, the purchaser will be entitled to primary energy dispatch right for the facility's generating capacity. The agreement is subject to the amendment of the El Segundo RMR agreement to switch to RMR Condition I and to otherwise allow the purchaser to exercise its primary dispatch rights under this agreement while preserving Cal ISO's ability to call on the El Segundo facility as a reliability resource under the RMR agreement, if necessary. The RMR contract on approximately 45 MW of generating capacity at Red Bluff expired on December 31, 2004 and will not be renewed for 2005.

The West Coast region's power generation assets as of December 31, 2004 are summarized in the table below.

Name and Location of Facility	Power Market	Net Owned Capacity (MW)	NRG's Percentage Ownership Interest	Fuel Type
Encina, California	Cal ISO	483	50%	Gas/Oil
El Segundo Power, California	Cal ISO	335	50%	Gas
Long Beach Generating, California*	Cal ISO	265	50%	Gas
San Diego Combustion Turbines, California	Cal ISO	85	50%	Gas/Oil
Saguaro Power Co., Nevada	WECC	53	50%	Gas/Oil
Chowchilla, California	Cal ISO	49	100%	Gas
Red Bluff, California	Cal ISO	45	100%	Gas

* Retired effective January 1, 2005

Market Framework. Our West Coast region assets are primarily located within the control area of Cal ISO. Cal ISO operates a financially settled "Real-time" balancing market similar to the regional ISOs in the northeast area of the U.S. Cal ISO's "Day Ahead" energy markets are similar to those in the South Central region, with all power sales and purchases consummated bilaterally between individual counter-parties and scheduled for physical delivery with Cal ISO.

Market Developments. In California, Cal ISO continues with its plan to move toward markets similar to PJM, NYISO and ISO-NE, with its Market Redesign & Technology Upgrade, or MRTU, formerly known as MD02 (market design 2002). The proposed changes will re-establish a "real-time" market and allow for multiple settlements. NRG Energy views this as an improvement to the existing structure. In general, Cal ISO is continuing along a path of small incremental changes, rather than implementing a comprehensive market restructuring. The effect of the new MRTU changes on NRG Energy cannot be determined at this time.

In addition to the Cal ISO's market changes, numerous legislative initiatives in California create uncertainty and risk for us. Most significantly, SB39XX mandates that the California Public Utilities Commission, or CPUC, exercise jurisdiction over the operating and maintenance procedures of wholesale power generators including the setting of operating, maintenance and logbook standards. On October 28, 2004, the CPUC issued draft orders directing in-state utilities to meet a 15-17% reserve requirement by no later than June 2006, and establishing a requirement that the utilities acquire 90% of their capacity needs a year in advance. This order may present opportunities for West Coast Power to enter into new bilateral agreements.

In September 2004, Governor Schwarzenegger vetoed AB2006, commonly referred to as the "re-regulation" initiative, with a promise to the people of California to create a competitive energy market in California that will attract the investment capital required to meet growing load obligations.

Other North America

Facilities. As of December 31, 2004, we owned approximately 1,591 MW of net generating capacity in other regions of the U.S.

Our Other North America power generation assets as of December 31, 2004 are summarized in the table below.

Name and Location of Facility	Power Market	Net Owned Capacity (MW)	NRG's Percentage Ownership Interest	Fuel Type
Audrain, Missouri*	MAIN	640	100%	Gas
Rockford I, Illinois	MAIN	342	100%	Gas
Rockford II, Illinois	MAIN	171	100%	Gas
Rocky Road Power, Illinois	PJM	175	50%	Gas
Ilion, New York	NYISO	60	100%	Gas/Oil
Dover, Delaware	PJM	106	100%	Gas/Oil
James River, Virginia*	SERC-TVA	55	50%	Coal
Paxton Creek Cogeneration	PJM	12	100%	Gas
Other — 3 projects*	Various	30	Various	Various

* May sell or dispose of in the next 12 months.

Australia

Facilities. As of December 31, 2004, we owned approximately 1,390 MW of net generating capacity in Australia. The Flinders assets are comprised of the Northern Power Station which provides 520 MW, the refurbished Playford Power Station, which provides 240 MW and the Leigh Creek Coal Mine which supplies coal to both plants. The 1,680 MW Gladstone Plant, of which we own 37.5%, is operated by NRG Energy.

Our Australian power generation assets as of December 31, 2004 are summarized in the table below.

Name and Location of Facility	Purchaser/ Power Market	Net Owned Capacity (MW)	NRG's Percentage Ownership Interest	Fuel Type
Flinders, South Australia	National Electricity Market	760	100%	Coal
Gladstone Power Station, Queensland	Enertrade/Boyne Smelters	630	37.5%	Coal

Market Framework

The National Electricity Market operates across the interconnected states of southern and eastern Australia. The market represents a physical wholesale trading exchange based on merit order generation dispatch and gross pool settlement, within an energy-only market design. The physical market is managed by National Electricity Market Management Co. Ltd., or NEMMCO, as the independent market operator, with spot prices determined on a regional basis in half-hourly trading intervals, capped at a maximum of AUD 10,000/MWh. The majority of wholesale trading occurs through bilateral financial (hedge) contracts between counter-parties on a regional basis, with some limited financial trading through exchange traded futures.

The Flinders plant operates within the market as a merchant portfolio. Northern Power Station (520 MW base load) and Playford Power Station (240 MW mid merit) are the only coal-fired units in South Australia. Their output, together with the output of the gas fired Osborne Power Station (output purchased under long-term power purchase agreements, or PPAs) supply over 40% of the state's electricity. All output is market traded, with revenue streams protected by hedge contracts for a large proportion of forward output.

The output of Gladstone is fully contracted under long-term PPAs to an adjacent aluminum smelter and a government entity that trades its portion into the market.

Market Development

In late 2003, the governments spanning the National Electricity Market embarked upon a series of reforms to address perceived deficiencies in the governance and institutional structure of the market. These reforms are proceeding under cooperative legislation expected to be in operation by mid-2005, and include the creation of a new national energy regulator and the establishment of a more efficient process to change and administer the rules governing the operation of the market.

These reforms are not intended to alter the operation or fundamental design of the market, but are designed to streamline the administration of the wholesale market, increase regulatory certainty for investors, and improve rule change and decision-making processes in both the electricity and gas sectors.

Further policy announcements are expected in the near future in relation to electricity transmission planning and regulation, trading region boundary change arrangements, and funding arrangements for the new institutional bodies.

Other International

Facilities. Over the past decade, through our foreign subsidiaries, we invested in international power generation projects in Australia, Europe and Latin America. During 2002, 2003 and 2004, we sold international generation projects with an aggregate total generating capacity of approximately 600 MW, 1,640 MW and 833 MW, respectively. As of December 31, 2004, we had investments in power generation projects located in the United Kingdom, Germany and Brazil with approximately 768 MW of net generating capacity.

Our Other International power generation assets as of December 31, 2004 are summarized in the table below.

Name and Location of Facility	Purchaser/ Power Market	Net Owned Capacity (MW)	NRG's Percentage Ownership Interest	Fuel Type
Europe:				
Enfield Energy Centre, UK*	UK Electricity Grid	95	25%	Gas
Schkopau Power Station, Germany	Vattenfall Europe	400	42%	Coal
MIBRAG mbH, Germany**	ENVIA/MIBRAG Mines	119	50%	Coal
Brazil:				
Itiquira Energetica, Brazil*	COPEL	154	99%	Hydro

* NRG may sell or dispose of in the next 12 months.

** Primarily a coal mining facility.

Alternative Energy and Services

We own alternative energy generation facilities through NEO Corporation, or NEO, and through our NRG Resource Recovery business division, which converts municipal solid waste, or MSW, into refuse derived fuel suitable to burn in third party power plants.

NEO Corporation. NEO is a wholly-owned subsidiary that was formed to develop power generation facilities ranging in size from one to 49 MW in the United States. As of December 31, 2004, NEO had 41 MW of net ownership interests in 15 hydroelectric facilities and 98.6 MW of net ownership interests in four distributed generation facilities including 94 MW of gas-fired peaking engines in California (referred to as the Red Bluff and Chowchilla facilities and included in our summary of the West Coast region). Certain of the assets owned by NEO are currently being marketed. See "Significant Dispositions of Non-Strategic Assets" under this Item 1 for more information.

Resource Recovery Facilities. Our Resource Recovery business is focused on owning and operating alternative fuel/"green power" generation and fuels processing projects. The alternative fuels currently processed and combusted are municipal solid waste, urban wood waste (pallets, clean construction debris, etc.), and non-recyclable waste paper and compost. Our Resource Recovery business has municipal solid waste processing capacity of approximately 2,800 tons per day. Our Resource Recovery business owns and operates municipal solid waste processing facilities in Minnesota, as well as NRG Processing Solutions, including ten composting and biomass fuel processing sites in Minnesota, three of which are permitted to operate as municipal solid waste transfer stations.

Our significant Resource Recovery assets as of December 31, 2004 are summarized in the table below.

Name and Location of Facility	Purchaser/ MSW Supplier	Net Owned Capacity	NRG's Percentage Ownership Interest	Fuel Type
Newport, MN*	Ramsey and Washington Counties	1,500 tons/day	100%	Refuse Derived Fuel
Elk River, MN**	Anoka, Hennepin and Sherburne Counties; Tri-County Solid Waste Management Commission	1,275 tons/day	85%	Refuse Derived Fuel

* The Newport facilities are related strictly to municipal solid waste processing (MSW).

** Our 85% interest in the Elk River facility is related strictly to municipal solid waste processing.

Non-Generation

In addition to our traditional power generation facilities discussed above, we have interests in district heating and cooling systems and steam transmission operations through our subsidiary, NRG Thermal LLC. NRG Thermal's steam and chilled water businesses have a steam and chilled water capacity of approximately 1,225 megawatt thermal equivalents, or MWt.

As of December 31, 2004, NRG Thermal owned five district heating and cooling systems in Minneapolis, Minnesota; San Francisco, California; Pittsburgh, Pennsylvania; Harrisburg, Pennsylvania; and San Diego, California. These systems provide steam heating to approximately 565 customers and chilled water to 90 customers. In addition, NRG Thermal owns and operates three projects that serve industrial/government customers with high-pressure steam and hot water, an 88 MW combustion turbine peaking generation facility and an 18 MW coal-fired cogeneration facility in Dover, Delaware (included in the summary of the Other North America region).

Our thermal and chilled water assets as of December 31, 2004 are summarized in the table below.

Name and Location of Facility	Customers	Net Owned Capacity*	NRG's Percentage Ownership Interest	Fuel Type
NRG Energy Center Minneapolis, Minnesota	Approx. 100 steam customers and 45 chilled water customers	Steam: 1,203 mm Btu/hr. (353 MWt) Chilled water: 41,630 tons (146 MWt)	100%	Gas/Oil
NRG Energy Center San Francisco, California	Approx. 170 steam customers	Steam: 482 mm Btu/hr. (141 MWt)	100%	Gas
NRG Energy Center Harrisburg, Pennsylvania	Approx. 270 steam customers and 3 chilled water customers	Steam: 440 mm Btu/hr. (129 MWt) Chilled water: 2,400 tons (8 MWt)	100%	Gas/Oil
NRG Energy Center Pittsburgh, Pennsylvania	Approx. 25 steam and 25 chilled water customers	Steam: 266 mm Btu/hr. (78 MWt) Chilled water: 12,580 tons (44 MWt)	100%	Gas/Oil
NRG Energy Center San Diego, California	Approx. 20 chilled water customers	Chilled water: 7,425 tons (26 MWt)	100%	Gas
NRG Energy Center St. Paul, Minnesota	Rock-Tenn Company	Steam: 430 mm Btu/hr. (126 MWt)	100%	Coal/Gas/Oil
Camas Power Boiler Washington	Georgia-Pacific Corp.	Steam: 200 mm Btu/hr. (59 MWt)	100%	Biomass
NRG Energy Center Dover, Delaware	Kraft Foods, Inc.	Steam: 190 mm Btu/hr. (56 MWt)	100%	Coal
NRG Energy Center Bayport, Minnesota	Andersen Corporation and Minnesota Correctional Facility	Steam: 200 mm Btu/hr. (59 MWt)	100%	Coal/Gas/Propane

* Thermal production and transmission capacity is based on 1,000 Btus per pound of steam production or transmission capacity. The unit mmBtu is equal to one million Btus.

Energy Marketing

Our wholly-owned energy marketing subsidiary, NRG Power Marketing, Inc., or PMI, began operations in 1998. PMI provides a full range of energy management services for our domestic generation facilities. These services are provided under bilateral contracts or agreements pursuant to which PMI engages in the sale, purchase and trading of energy, capacity and ancillary services from the facilities, transacts in and trades the fuel (coal, oil and natural gas) and associated transportation, and manages and trades the emission allowance credits for these facilities. A significant responsibility of PMI is to recommend to senior management commercial hedge transactions in an effort to manage risk and to maximize earnings and cash flow for NRG Energy. In addition, PMI provides all necessary ISO bidding, dispatch, and transmission scheduling for the facilities. PMI also utilizes its contractual arrangements with third parties to procure fuel, to sell energy, capacity and ancillary services to minimize administrative costs and burdens and reduce the collateral requirements imposed by third party suppliers and purchasers.

NRG Worldwide Operations

Our wholly-owned subsidiary, NRG Worldwide Operations, or NRG Operations, provides operating and maintenance services to our generation facilities. These services include providing experienced personnel for the operation and administration of each facility and oversight out of the corporate office to balance resources, share expertise and best practices, and to ensure the optimum utilization of resources available to the facilities. In addition, NRG Operations provides overall facilities management, strategic planning, and the development and dissemination of consistent Company policies and practices relating to operations.

Financial Information About Segments and Geographic Areas

For financial information on our operations on a geographical and on a segment basis, see Item 15 — Note 23 to the Consolidated Financial Statements.

Dispositions of Non-Strategic Assets

We continue to market our interest in our remaining non-core assets. Since 2003, we sold or made arrangements to sell a number of consolidated businesses and equity investments in an effort to reduce our debt, improve liquidity and rationalize our investments. Dispositions completed during 2004 are summarized in the following chart:

Asset (Location)	Segment	Closing Date	Proceeds	Gain/(Loss) on Disposition	Debt Reduction
				(In thousands)	
Calpine Cogeneration	Other North America	3/07/2004	$ 3.0	$ 0.7	$ —
Loy Yang (Australia)	Australia	4/08/2004	26.7	(1.3)	—
PERC (Maine)	Other North America	4/16/2004	18.4	3.2	25.2
Cobee (Bolivia)	Other International	4/27/2004	50.0	2.8	24.1
Hsin Yu (Taiwan)	Other International	5/13/2004	1.0	10.3	46.4
McClain (Oklahoma)	Other North America	7/09/2004	160.2	(3.0)	156.5
Batesville (Mississippi)	Other North America	7/24/2004	27.6	11.0	289.3
NEO projects	Alternative Energy	9/30/2004	5.8	6.0	—
NEO equity projects	Alternative Energy	9/30/2004	6.1	(3.8)	—
CALP, Virginia	Other North America	11/30/2004	14.9	(4.6)	—
Kendall, Illinois	Other North America	12/01/2004	1.0	(26.5)	448.4
Total			$314.7	$ (5.2)	$989.9

Significant Customers

Reorganized NRG

For the year ended December 31, 2004, we derived approximately 49.8% of our total revenues from majority-owned operations from four customers: NYISO accounted for 28.5%, ISO New England accounted for 9.1%, National Electricity Market Management Co. Ltd (Australia) accounted for 6.8% and Vattenfall Europe (Germany) accounted for 5.4%. We account for the revenues attributable to NYISO and ISO-NE as part of our North American power generation segment. We account for the revenues attributable to National Electricity Market Management and Vattenfall Europe as part of our International segment. For the period December 6, 2003 through December 31, 2003, we derived approximately 39.0% of our total revenues from majority-owned operations from two customers: NYISO accounted for 26.5% and ISO-NE accounted for 12.5%. ISO-NE and NYISO are ISOs or RTOs and are FERC-regulated entities that administer a residual (spot) energy market and manage transmission assets collectively under their respective control to provide non-discriminatory access to the transmission grid. The NYISO exercises operational control over most of New York State's transmission facilities. We anticipate that NYISO will continue to be a significant customer given the scale of our asset base in the NYISO control area.

Predecessor Company

For the period January 1, 2003 through December 5, 2003 and for the year ended December 31, 2002, sales to one customer, NYISO, accounted for 33.4% and 26.0% of our total revenues from majority-owned operations, respectively.

Seasonality and Price Volatility

Annual and quarterly operating results can be significantly affected by weather and price volatility. Significant other events, such as the demand for natural gas and relative levels of hydroelectric capacity can increase seasonal fuel and power price volatility. We derive a majority of our annual revenues in the months of May through September, when demand for electricity is the highest in our North American markets. Further, volatility is generally higher in the summer months due to the effect of temperature variations. Our second most important season is winter when volatility and price spikes in underlying fuel prices have tended to drive seasonal electricity prices. Issues related to seasonality and price volatility are fairly uniform across our business segments.

Sources and Availability of Raw Materials

Our raw material requirements primarily include various forms of fossil fuel, including oil, natural gas and coal. We obtain our oil, natural gas and coal from multiple sources and availability is generally not an issue, although localized shortages, transportation availability and supplier financial stability issues can and do occur. The prices of oil, natural gas and coal are subject to macro- and micro-economic forces that can change dramatically in both the short-term and the long-term. For example, the price of natural gas was particularly volatile in mid-January 2004 due to the extreme temperatures experienced in the Northeast. Additionally, throughout 2004, oil prices were extremely high due to the geo-political uncertainty in the Middle East and increased demand by China and India. The total cost of oil, natural gas and coal represented approximately 41.6%, 37.5%, 42.4% and 15.1% of our total operating costs and expenses for the year ended December 31, 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003, and for the year ended December 31, 2002, respectively. Issues related to the sources and availability of raw materials are fairly uniform across our business segments.

Employees

As of December 31, 2004, we had 2,644 employees, approximately 555 of whom are employed directly by us and approximately 2,089 of whom are employed by our wholly-owned subsidiaries and affiliates. Approximately 1,011 employees are covered by bargaining agreements. During 2004, we experienced no significant labor stoppages or labor disputes at our facilities.

Federal Energy Regulation

Federal Energy Regulatory Commission. The FERC is an independent agency that regulates the transmission and wholesale sale of electricity in interstate commerce under the authority of the Federal Power Act, or FPA. In addition, FERC determines whether a generation facility qualifies for Exempt Wholesale Generator, or EWG, status under Public Utility Holding Company Act of 1935, or PUHCA. FERC also determines whether a generation facility meets the ownership and technical criteria of a Qualifying Facility, or QF, under Public Utility Regulatory Policies Act of 1978, or PURPA.

Federal Power Act. The FPA gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and transmission of electricity in interstate commerce. FERC regulates the owners of facilities used for the wholesale sale of electricity or transmission in interstate commerce as "public utilities." The FPA also gives FERC jurisdiction to review certain transactions and numerous other activities of public utilities. Our QFs are exempt from the FERC's FPA rate regulation.

Public utilities are required to obtain FERC's acceptance of their rate schedules for wholesale sales of electricity. Because our non-QF generating companies are selling electricity in the wholesale market, such generating companies are deemed to be public utilities for purposes of the FPA. FERC has granted our generating and power marketing companies the authority to sell electricity at market-based rates. Usually, the FERC's orders that grant our generating and power marketing companies market-based rate authority reserve the right to revoke or revise that authority if FERC subsequently determines that we can exercise market power in transmission or generation, create barriers to entry or engage in abusive affiliate transactions. If our generating and power marketing companies were to lose their market-based rate authority, such companies may be required to obtain FERC's acceptance of a cost-of-service rate schedule and may become subject to the accounting, record-keeping and reporting requirements that are imposed on utilities with cost-based rate schedules.

In addition, the FPA gives FERC jurisdiction over a public utility's issuance of securities or assumption of liabilities. However, FERC usually grants blanket approval for future securities issuances or assumptions of liabilities to entities with market-based rate authority. In the event that one of our public utility generating companies were to lose its market-based rate authority, our future securities issuances or assumptions of liabilities could require prior approval of the FERC.

The FPA also requires the FERC's prior approval for the transfer of control over assets subject to FERC's jurisdiction. FERC has jurisdiction over certain facilities used to interconnect our generating projects to the transmission grid, and over the filed rate schedules and tariffs of our EWG generating projects and power marketing operating companies. Thus, transferring these assets would require FERC approval.

In New England, New York, the Mid-Atlantic region, the Midwest and California, FERC has approved independent system operators or regional transmission organizations, or ISOs or RTOs. Most of these ISOs or RTOs administer a wholesale centralized bid-based spot market in their regions pursuant to tariffs approved by FERC. These tariffs/market rules dictate how the day-ahead and real-time markets operate and how entities with market-based rates shall be compensated within those markets. The ISOs or RTOs in these regions also control access to and the operation of the transmission grid within their footprint. Outside of ISO or RTO-controlled regions, we are allowed to sell energy at market-based rates as determined by willing buyers and sellers. Access to, pricing for, and operation of the transmission grid in such regions is controlled by the local transmission owning utility according to its Open Access Transmission Tariff approved by FERC.

Public Utility Holding Company Act. PUHCA defines as a "holding company" any entity that owns, controls or has the power to vote 10% or more of the outstanding voting securities of a "public utility company." Unless exempt, a holding company is required to register with the Securities and Exchange Commission, or the SEC, and it and its Subsidiaries (i.e., a company with 10% of its voting securities held by the registered holding company) become subject to extensive regulation. Registered holding companies under PUHCA are required to limit their utility operations to a single, integrated utility system and divest any other operations that are not functionally related to the operation of the utility system. In addition, a company that is a Subsidiary of a registered holding company is subject to financial and organizational regulation, including approval by the SEC of certain financings and transactions. Domestic generating facilities that qualify as QFs and/or that have obtained EWG status from FERC are exempt from PUHCA. Each of our domestic generating subsidiaries has been designated by FERC as an EWG or is otherwise exempt from PUHCA because it is a QF under PURPA. Because our generating subsidiaries have EWG or QF status, we do not qualify as a "holding company" under PUHCA. We will not be subject to regulation under PUHCA as long as (a) we do not become a Subsidiary of another registered holding company and (b) the projects in which we have an interest (1) qualify as QFs under PURPA, (2) obtain and maintain EWG status under Section 32 of PUHCA, (3) obtain and maintain Foreign Utility Company, or FUCO, status under Section 33 of PUHCA, or (4) are subject to another exemption or waiver. If our projects were to cease to be exempt and we were to become subject to SEC regulation under PUHCA, it would be difficult for us to comply with PUHCA absent a substantial corporate restructuring.

Regulatory Developments. FERC is attempting to spur deregulation of the wholesale markets by requiring transmission owners to provide open, non-discriminatory access to electricity markets and the transmission grid. In April 1996, FERC issued Orders 888 and 889, which required all public utilities to file "open access" transmission tariffs that give wholesale generators, as well as other wholesale sellers and buyers of electricity, access to transmission facilities on a non-discriminatory basis. This led to the formation of the ISOs described above. On December 20, 1999, FERC issued Order 2000, encouraging the creation of RTOs. On July 31, 2002, FERC issued its Notice of Proposed Rulemaking regarding Standard Market Design, or SMD. All three orders were intended to eliminate market discrimination by incumbent vertically integrated utilities and to provide for open access to the transmission grid. The status of FERC's RTO and SMD initiatives is uncertain. On April 28, 2003, FERC issued a white paper describing proposed changes to the proposed SMD rulemaking that would, among other things, allow for more regional differences. In addition, the Energy Bill pending before Congress could restrict FERC's ability to implement these initiatives.

The full effect of these changes on us is uncertain at this time, because in many parts of the United States it has not been determined how entities will attempt to comply with FERC's initiatives. At this time, five ISOs have been approved and are operational: ISO-NE in New England; the NYISO in New York; PJM in the Mid-Atlantic region; the Midwest Independent System Operation, or MISO, in the Central Midwest region; and the Cal ISO in California. Three of these ISOs: PJM, MISO and ISO-NE, have been found to also qualify as RTOs.

We are affected by rule/tariff changes that occur in the existing ISOs and RTOs. The ISOs and RTOs that oversee most of the wholesale power markets have in the past imposed, and may in the future continue to impose, price limitations and other mechanisms to address some of the volatility in these markets. For example, ISO-NE, NYISO, PJM and Cal ISO have imposed price limitations. These types of price limitations and other regulatory mechanisms may adversely affect the profitability of our generation facilities that sell energy into the wholesale power markets. In addition, the regulatory and legislative changes that have recently been enacted in a number of states in an effort to promote competition are novel and untested in many respects. These new approaches to the sale of electric power have very short operating histories, and it is not yet clear how they will operate in times of market stress or pressure, given the extreme volatility and lack of meaningful long-term price history in many of these markets and the imposition of price limitations by independent system operators.

Environmental Matters

We are subject to a broad range of foreign, federal, state and local environmental and safety laws and regulations in the development, ownership, construction and operation of our domestic and international projects. These laws and regulations impose requirements on discharges of substances to the air, water and land, the handling, storage and disposal of, and exposure to, hazardous substances and wastes and the cleanup of properties affected by pollutants. These laws and regulations generally require that we obtain governmental permits and approvals before construction or operation of a power plant commences, and after completion, that our facilities operate in compliance with those permits and applicable legal requirements. We could also be held responsible under these laws for the cleanup of pollutants released at our facilities or at off-site locations where we may have sent wastes, even if the release or off-site disposal was conducted in compliance with the law.

Environmental laws have become increasingly stringent over time, particularly the regulation of air emissions from our plants. Such laws generally require regular capital expenditures for power plant upgrades, modifications and the installation of certain pollution control equipment. In addition, regulatory compliance for the construction of new facilities is a costly and time-consuming process. Intricate and rapidly changing environmental regulations may require major capital expenditures for permitting and create a risk of expensive delays or material impairment of project value if projects cannot function as planned due to changing regulatory requirements or local opposition. In all cases, we seek to reflect environmental impacts and mitigants in every business decision we make, and by doing so, strive to improve our competitive advantage by meeting or exceeding environmental and safety requirements in the management and operation of our assets.

It is not possible at this time to determine when or to what extent additional facilities or modifications to existing or planned facilities will be required as a result of potential changes to environmental and safety laws and regulations, regulatory interpretations or enforcement policies. In general, future laws and regulations are expected to require the addition of pollution control equipment or the imposition of certain restrictions on our operations. We expect that future liability under, or compliance with, environmental and safety requirements could have a material effect on our operations or competitive position.

Domestic Environmental Regulatory Matters

Power projects are subject to stringent environmental and safety protection and land use requirements in the U.S. These laws and regulations generally require lengthy and complex processes to obtain licenses, permits and approvals from federal, state and local agencies. If such laws and regulations become more stringent and our facilities are not exempted from coverage, we could be required to make extensive modifications to further reduce potential environmental impacts.

We establish accruals where it is probable that we will incur environmental costs under applicable law or contract and it is possible to reasonably estimate those costs. We adjust the accruals when new remediation or other environmental liability responsibilities are discovered and probable costs become estimable, or when current liability estimates are adjusted to reflect new information or a change in the law.

U.S. Federal Environmental Initiatives

Several federal regulatory and legislative initiatives to further limit and control pollutant emissions from fossil fuel-fired combustion units are currently underway. Although neither the exact impact of these initiatives nor their final form is known at this time, all of our power plants will likely be affected in some manner by the expected changes in federal environmental laws and regulations. In Congress, legislation has been proposed that would impose annual caps on U.S. power plant emissions of nitrogen oxides, or NO_X, sulfur dioxide, or SO_2, mercury and, in some instances, carbon dioxide, or CO_2.

In December 2003, the U.S. Environmental Protection Agency, or USEPA, proposed rules governing mercury emissions from power plants. On March 15, 2005, USEPA issued the Clean Air Mercury Rule, or CAMR, to permanently cap and reduce mercury emissions from coal-fired power plants. CAMR imposes limits on mercury emissions from new and existing coal-fired plants and creates a market-based cap-and-trade program that will reduce nationwide utility emissions of mercury in two phases (2010 and 2018), to achieve an ultimate reduction level of approximately 70%. The cap-and-trade program for mercury is expected to be structured like the federal Acid Rain Program, allowing generators to decide in each particular case the most effective means for their compliance (i.e., install control technologies and/or purchase emissions allowances in the market). As there has been significant debate on whether USEPA has authority to regulate mercury emissions through the proposed cap-and-trade mechanism (as opposed to a command-and-control requirement to install "maximum achievable control technology", or MACT, on a unit basis), it is reasonable to expect that the new rule may be subject to legal challenge. Each of our coal-fired electric power plants will be subject to mercury regulation. However, since the final rule has yet to be implemented by individual states pursuant to state-specific legislation, it is not possible to identify in detail how the final mercury rules will affect our operations located in those states. Nevertheless, we continue to actively review emerging mercury monitoring and mitigation technologies and assess appropriate options for the Company in future.

The USEPA has also proposed MACT standards for nickel from oil-fired units. The proposed nickel rule would accept the use of an electrostatic precipitator, or ESP, as the appropriate MACT control, with an implementation date of three years after rule promulgation. Eight of the Company's oil-fired generating units are not equipped with an ESP: Middletown Unit 4, Montville Unit 6, Vienna and Encina Units 1-5. While

USEPA's final decision regarding nickel emissions from oil-fired units is still pending, USEPA is reconsidering whether, based on the scientific data, any new controls on nickel emissions from oil-fired generators are in fact needed. Given the current situation, we do not consider any material expenditure for nickel emission mitigation by the Company to be probable at this time.

The USEPA has finalized federal rules governing ozone season NO_X emissions across the eastern U.S. Current ozone season rules are being implemented within two programs. Restrictions exist in the Ozone Transport Region, or OTR, through annual ozone seasons (May – September) and all of the Company's generating units located in the OTR are included in this program (which was effective in 2003). NO_X allowance allocations are based on an equivalent emissions rate of 0.15 lbs/MMBtu, with each OTR state managing its own NO_X Budget Program and specific rules for allowance distribution. The second program, in effect from May 2004, is similar to the OTR program, and extends to states within the Ozone Transport Assessment Group, or OTAG, region. This restricts 2004 and subsequent ozone season NO_X emissions in most states east of the Mississippi River. These rules essentially require one NO_X allowance to be held for each ton of NO_X emitted from fossil fuel-fired stationary boilers, combustion turbines, or combined cycle systems. NO_X allowance allocation is similar to the OTR and each of the Company's facilities that is subject to these rules has been allocated NO_X emissions allowances. While the portfolio total is currently sufficient to cover operations at these facilities, if at any point allowances are insufficient for the anticipated operation of each of these facilities, the Company must purchase NO_X allowances. Any need to purchase additional NO_X allowances could have a material adverse effect on our operations.

On March 10, 2005, the USEPA announced the Clean Air Interstate Rule, or CAIR, originally proposed in January 2004. The new rule applies to 28 eastern states and the District of Columbia and caps SO_2 and NO_X emissions from power plants in two phases: 2010 and 2015 for SO_2 and 2009 and 2015 for NO_X. CAIR will reduce such emissions in aggregate by just over 70% in the case of SO_2 and just under 70% in the case of NO_X and will apply to certain of the Company's power plants located in New York, Massachusetts, Connecticut, Delaware (NO_X only) and Louisiana. States must achieve the required emission reductions using one of two compliance options: (a) meet the state's emission budget by requiring power plants to participate in a USEPA-administered interstate cap-and-trade system; or (b) meet an individual state emissions budget through measures selected by individual states. While the Company's current business plans include initiatives (for example, the conversion of Huntley and Dunkirk to burn low sulfur coal) in part to address the new emissions caps, until the final rule as issued by USEPA is actually implemented by specific state legislation, it is not possible to identify with greater specificity the effect of CAIR on the Company.

In 2004, USEPA reproposed the 1999 Regional Haze Rule, designed to improve air quality in national parks and wilderness areas. This rule requires regional haze controls (by targeting SO_2 and NO_X emissions from sources including power plants) through the installation of Best Available Retrofit Technology, or BART, for certain sources put into operation between 1962 and 1977. The so-called BART rule is expected to be finalized in April 2005, with states required to submit their implementation plans by 2008. It is likely that the BART rule, if implemented, will affect many of the Company's facilities. However, it is also expected that required actions taken for compliance with CAIR (when it is fully implemented) and certain state initiatives will also achieve compliance with the BART rule as currently proposed.

During the first quarter of 2002, USEPA proposed new rules governing cooling water intake structures at existing power facilities (the Phase II 316(b) Rules). These rules were finalized in February 2004. The Phase II 316(b) Rules specify certain location, design, construction, and capacity standards for cooling water intake structures at existing power plants using the largest amounts of cooling water. These rules will require implementation of the Best Technology Available, or BTA, for minimizing adverse environmental impacts unless a facility shows that such standards would result in very high costs or little environmental benefit. The Phase II 316(b) Rules require the Company's facilities that withdraw water in amounts greater than 50 million gallons per day to submit certain surveys, plans, operational measures, and restoration measures (with wastewater permit applications or renewal applications) that would minimize certain adverse environmental impacts of impingement or entrainment. The Phase II 316(b) Rules affect a number of the Company's plants, specifically those with once-through cooling systems. Compliance options include the addition of control technology, modified operations, restoration, or a combination of these, and are subject to a comparative cost and cost/benefit justification. While we have conducted a number of the requisite studies (and in one case already budgeted to install BTA), until all the needed studies throughout our fleet have been completed and consultations on the results have occurred with USEPA (or its delegated state or regional agencies), it is not possible to estimate the capital costs that will be required for compliance with the Phase II 316(b) Rules.

Federal legislation, such as the Clear Skies Act, or Clear Skies, has been proposed that would impose annual caps on U.S. power plant emissions of NO_X, SO_2, mercury, and, in some instances, CO_2. Under Clear Skies, these caps would go into effect in two phases: 2010 and 2016 for SO_2; 2008 and 2016 for NO_X; and 2010 and 2016 for mercury, with the proposed final reduction level in 2016 for SO_2, NO_X and mercury being approximately 70%. Clear Skies was first proposed in 2002 and while the bill stalled in Senate Committee on March 9, 2005, the Bush Administration continues to support, and work with Congress to achieve, passage of Clear Skies in 2005. Clear Skies overlaps to a significant degree with the USEPA CAIR and CAMR, and would modify or supersede those rules if enacted as federal legislation.

While the Bush Administration has publicly stated that it does not support mandatory national restrictions on greenhouse gas, or GHG, emissions, it supports a number of initiatives with respect to voluntary reductions of "carbon intensity" (a measure of carbon emissions per unit of GDP). A number of members of the Senate and Congress continue to call for federal GHG regulation and to propose legislation. Additionally, there have been several petitions from states and other parties to compel USEPA to regulate GHGs under the Clean Air Act, or CAA. On September 3, 2003, USEPA denied a petition by Massachusetts, Maine and Connecticut to require USEPA to establish a National Ambient Air Quality Standard, or NAAQS, for CO_2. Since that time, twelve states and other territorial entities have filed suit against USEPA asking the Court to address whether USEPA has an existing obligation to regulate GHGs under the CAA. Oral arguments in the case are scheduled for April, 2005. Additionally, eight states and the City of New York filed suit on July 21, 2004 against American Electric Power Company, Southern Company, Tennessee Valley Authority, Xcel Energy, Inc. and Cinergy Corporation, alleged to be the nation's five largest emitters of GHGs and all of which are owners of electric generation. On the same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of certain special interest groups. In both cases, the complaint seeks an injunction against each defendant forcing it to abate its contribution to the "global warming nuisance" by requiring it to cap its CO_2 emissions and then reduce them by a specified percentage each year for at least a decade. The outcome of this litigation and proposed legislation cannot be predicted. The Company's compliance costs with any mandated GHG reductions in the future could be material.

Other federal initiatives that could affect the Company's generating facilities with respect to fine particulate matter (PM2.5), and ozone are underway, with compliance implementation timeframes expected from 2009.

Regional U.S. Regulatory Initiatives

Northeast Region. Connecticut rules on air regulation require certain reductions in emissions of SO_2 (in two steps: 2002 and 2003). The Company's Connecticut plants have operated in compliance with both phases of the rule. The Company also complies with Connecticut's NO_X emission rules (restricting the average, non-ozone season NO_X emission rate to 0.15 lbs/MMBtu), through selective firing of natural gas, use of selective non-catalytic reduction, or SNCR, technology presently installed at the Norwalk Harbor and Middletown Power Stations, improved combustion controls, use of emission reduction credits, and purchase of allowances. In 2002, the Connecticut legislature passed a law further tightening air emission standards by eliminating emissions credit purchases after January 1, 2005 as a means of meeting Department of Environmental Protection, or DEP, regulatory standards for SO_2 emissions from older power plants. The Company plans to comply with the legislation through the use of lower sulfur oil.

Massachusetts air regulations prescribe schedules under which six existing coal-fired power plants in-state are required to meet stringent emission limits for NO_X, SO_2, mercury, and CO_2. The state has reserved the issue of control of carbon monoxide and particulate matter emissions for future consideration. Consistent with a permit to install natural gas reburn technology to meet the NO_X and SO_2 limits received in early 2003 from the Massachusetts Department of Environmental Protection, or MADEP, the Company has implemented that technology at Somerset station. On June 4, 2004, MADEP issued its regulation on the control of mercury emissions. The effect of this regulation is that starting October 1, 2006, Somerset will be capped at 13.1 lbs/year of mercury and as of January 1, 2008, Somerset must achieve a reduction in its mercury inlet-to-outlet concentration of 85%. The Company plans to meet the requirements through the management of its fuels, and the use of early and off-site reduction credits. Additionally, the Company has entered into an agreement with MADEP to retire or repower the Somerset station by the end of 2009. The Company is currently considering its options with respect to how it will address MADEP's CO_2 emission standards; part of this analysis depends upon the outcome of the model rule process currently underway for the Regional Greenhouse Gas Initiative, or RGGI, discussed below.

New York State Department of Environmental Conservation, or NYSDEC, rules reducing allowable SO_2 and NO_X emissions from large, fossil-fuel-fired combustion units in New York State became effective October 2004. The reductions are achieved through an allowance-based cap-and-trade program that affects only New York sources. Specifically, New York electric generators have to reduce SO_2 emissions to 25% below the levels allowed in the federal Acid Rain Program starting January 2005 and 50% below the levels allowed by federal Acid Rain Program starting in January 2008. Under this Acid Rain Deposition Program, or ADRP, electric generators also have to meet the ozone season NO_X emissions limit of 0.15 lbs/MMBtu year-round, starting October 2004. The Company's strategy for complying with the ADRP is to generate early reductions of SO_2 and NO_X emissions associated with fuel switching and use such reductions to extend the timeframe for implementing technological controls, which could ultimately include the addition of flue gas desulfurization, or FGD, and selective catalytic reduction, or SCR, equipment. On January 11, 2005, the Company reached an agreement with the State of New York and the NYSDEC in connection with voluntary emissions reductions at the Huntley and Dunkirk facilities, as discussed in Item 3 — Legal Proceedings. The Company does not anticipate that any material capital expenditures, beyond those already planned, will be required for our Huntley and Dunkirk plants to meet the current compliance standards in New York (including under the recent settlement) through the end of the decade.

While no rules affecting the Company's existing facilities have been formally proposed, Delaware has foreshadowed the development of MACT-comparable standards for SO_2, NO_X and mercury. Delaware is considering such rule-making based on recent determinations that portions of the state are in non-attainment for NAAQS for fine particulates, or PM2.5, and all of the state is in non-attainment for the NAAQS for 8-Hour Ozone. The Company is evaluating voluntary emissions reductions opportunities which may include blending low sulfur western coals. While Delaware has not yet issued a proposed rule, the Company is currently participating as a stakeholder in such policy-making efforts along with the Governor's Energy Task Force, legislators, the PSC and the Delaware Department of Natural Resources and Environmental Control, or DNREC. Further, Delaware has begun rule-making in regard to developing emissions standards for small combustion turbines and distributive generation sources and implementing USEPA's New Source Review, or NSR, revisions. In addition to air emission initiatives, Delaware has also established Total Maximum Daily Loading, or TMDL, standards for temperature in its watersheds and intends to establish one for mercury as well. The Company continues to participate in these developments and has filed comments with the relevant agencies.

In July 2003, nine northeastern states announced a regional initiative to establish a cap-and-trade GHG program for electric generators, referred to as the Regional Greenhouse Gas Initiative, or RGGI. The model RGGI rule is to be announced in 2005, with an estimate of two to three years for participating states to finalize implementing regulations. A proposed level of the RGGI cap has not been determined at this time. If implemented, our plants in New York, Delaware, Massachusetts, and Connecticut may be affected and our compliance costs with any mandated GHG reductions in the future could be material.

The Ozone Transport Commission, or OTC, was established by Congress and governs ozone and the NO_X budget program in certain eastern states, including Massachusetts, Connecticut, New York and Delaware. In January 2005, the OTC stepped up its efforts to develop a multi-pollutant regime (SO_2, NO_X, mercury and CO_2) that is expected to be completed by mid-2006 (with individual state implementation to follow), particularly if Clear Skies does not eventuate in 2005 or CAIR is perceived to be lenient. The Company continues to be engaged in the OTC stakeholder process. While it is not possible to predict the outcome of this regional legislative effort, to the extent that the OTC seeks to effect emissions requirements that are more stringent than currently proposed or existing regimes (including the recently reached New York settlement), the Company could be materially impacted.

South Central Region. The Louisiana Department of Environmental Quality, or LADEQ, has promulgated State Implementation Plan revisions to bring the Baton Rouge ozone non-attainment area into compliance with applicable NAAQS. The Company participated in development of the revisions, which require the reduction of NO_X emissions at the gas-fired Big Cajun I Power Station and coal-fired Big Cajun II Power Station to 0.1 lbs/MMBtu and 0.21 lbs/MMBtu NO_X, respectively (both based on heat input). This revision of the Louisiana air rules would constitute a change-in-law covered by agreement between Louisiana Generating LLC and the electric cooperatives (power offtakers) allowing the costs of added combustion controls to be passed through to the cooperatives. The capital cost of combustion controls required at the Big Cajun II Generating Station to meet the state's NO_X regulations will total about $10.0 million for Unit 1 and will be undertaken in 2005. Units 2 and 3 have already made such changes.

In the 1990s, the USEPA commenced an industry-wide investigation of coal-fired electric generators to determine compliance with environmental requirements under the CAA associated with repairs, maintenance, modifications and operational changes made to the facilities over the years. USEPA focused on whether the changes were subject to NSR regulations which require companies to obtain permits before making major modifications to their facilities and if deemed necessary, install control equipment to reduce air emissions. As a result of this ongoing investigation USEPA and several states have filed suits against a number of coal-fired power plants in mid-western and southern states alleging violations of the CAA NSR requirements. The U.S. District Court for the Southern District of Ohio issued a decision in August 2003 finding Ohio Edison Company in violation of the NSR provisions of the CAA. In United States v. Duke Energy Company, however, the U.S. District Court for the Middle District of North Carolina rejected the USEPA's interpretation, concluding that the exclusion for routine maintenance should be defined relative to what is routine for the particular industry, not what is routine for the particular unit at issue. On October 27, 2003, the USEPA's NSR rule on routine maintenance was published in the Federal Register. The new regulations, which are not retroactive, would establish an equipment replacement cost threshold of 20% for determining when major NSR requirements are triggered. An appeal opposing the rule was filed with the U.S. Court of Appeals. The effective date of the rule has been delayed pending review. In June 2004, the USEPA filed an appeal with the U.S. Court of Appeals for the Fourth Circuit from the decision in the Duke Energy case which is currently being heard with a ruling expected by summer 2005.

On January 27, 2004, Louisiana Generating, LLC and Big Cajun II received a request for information under Section 114 of the CAA from USEPA seeking information primarily related to physical changes made at Big Cajun II. Throughout 2004 Louisiana Generating, LLC and Big Cajun II submitted several responses to the USEPA's follow-up requests. On February 15, 2005, we received a Notice of Violation, or NOV, alleging violations of the NSR provisions of the CAA at Big Cajun 2 Units 1 and 2 from 1998 through the NOV date. Given the preliminary stage of this NOV process, the Company cannot predict the outcome of this matter at this time, but it is actively engaged with USEPA to address these issues.

West Coast Region. The El Segundo Generating Station is regulated by the South Coast Air Quality Management District, or SCAQMD. Before its retirement as of January 1, 2005, the Long Beach Generating Station was also regulated by SCAQMD. SCAQMD approved amendments to its Regional Clean Air Incentives Market, or RECLAIM, NO_X regulations on January 7, 2005. RECLAIM is a regional emission-trading program targeting NO_X reductions to achieve state and federal ambient air quality standards for ozone. Among other changes, the amendments reduce the NO_X RECLAIM Trading Credit, or RTC, holdings of El Segundo Power, LLC and Long Beach Generation LLC facilities by certain amounts. Notwithstanding these amendments, retained RTCs are expected to be sufficient to operate El Segundo Units 3 and 4 as high as 100% capacity factor.

Domestic Site Remediation Matters

Under certain federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products at the facility. We may also be held liable to a governmental entity or to third parties for property damage; personal injury and investigation and remediation costs incurred by the party in connection with hazardous material releases or threatened releases. These laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, or CERCLA, as amended by the Superfund Amendments and Reauthorization Act of 1986, or SARA, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and courts have interpreted liability under such laws to be strict (without fault), and joint and several. The cost of investigation, remediation or removal of any hazardous or toxic substances or petroleum products could be substantial. Although we have been involved in on-site contamination matters, to date, we have not been named as a potentially responsible party with respect to any off-site waste disposal matter.

Northeast Region. Ash is produced as a by-product of coal combustion at the Dunkirk, Huntley, Indian River and Somerset Generating Stations. The Company attempts to direct its coal ash to beneficial uses. Even so, significant amounts of ash are landfilled. At Dunkirk and Huntley ash is disposed of at landfills owned and operated by the Company and it maintains financial assurance to cover costs associated with landfill closure, post-closure care and monitoring activities. On April 30, 2003, the Company funded a trust in the amount of approximately $5.9 million to provide such financial assurance. The Company is also responsible for the costs associated with closure, post-closure care and monitoring of the ash landfill owned and operated by the Company at the Indian River facility. Financial assurance to provide for closure and post-closure costs at that location is currently maintained by a trust fund collateralized in the amount of approximately $6.7 million. The Company seeks to commence a project to utilize a quarter of its ash production in 2005 for beneficial local use. Additionally, the Company is working with DNREC to modify current landfill slope design to gain significant additional capacity at the existing landfill, thus delaying pending closure and expansion of the landfill. The Company must also maintain financial assurance for closing interim status Resource Conservation and Recovery Act, or RCRA, facilities at the Devon, Middletown, Montville and Norwalk Harbor Generating Stations. On April 30, 2003, the Company funded a trust in the amount of $1.5 million to provide RCRA financial assurance.

The Company inherited historical clean-up liabilities when it acquired the Somerset, Devon, Middletown, Montville, Norwalk Harbor, Arthur Kill and Astoria Generating Stations. During installation of a sound wall at Somerset Station in 2003, oil contaminated soil was encountered. The Company has delineated the general extent of contamination, determined it to be minimal, and has placed an activity use limitation on that section of the property. Site contamination liabilities arising under the Connecticut Transfer Act at the Devon, Middletown, Montville and Norwalk Harbor Stations have been identified. The Company has proposed a remedial action plan to be implemented over the next two to eight years (depending on the station) to address historical coal ash contamination at the facilities. The total estimated cost of this remedial action plan is not expected to exceed $1.5 million. Remedial obligations at the Arthur Kill generating station have been established in discussions between the Company and the NYSDEC and are estimated to cost between $1 million and $2 million. Remedial investigations continue at the Astoria generating station with long-term clean-up liability expected to be within the range of $2.5 million to $4.3 million. While installing groundwater-monitoring wells on the Astoria site to track remediation of a historical fuel oil spill, the drilling contractor encountered deposits of coal tar in two borings. The Company reported the coal tar discovery to the NYSDEC in 2003 and delineated the extent of this contamination. The Company may also be required to remediate the coal tar contamination and/or record a deed restriction on the property if significant contamination is to remain in place.

The Company has been put on notice that the prior owner of the Huntley, Dunkirk and Oswego plants is seeking indemnification and defense in connection with several lawsuits alleging liability for damages to persons allegedly exposed to asbestos-containing materials at the plants. The prior owner alleges that the Company is liable by the terms of the Asset Sales Agreements pursuant to which the Company acquired the plants, which allegations are disputed. To date, the prior owner has not filed suit against the Company with respect to its claim for indemnification with respect to these cases.

South Central Region. Liabilities associated with closure, post-closure care and monitoring of the ash ponds owned and operated at the Big Cajun II Generating Station are addressed through the use of a trust fund maintained by the Company. The value of the trust fund is approximately $5.0 million and the Company is making annual payments to the fund in the amount of approximately $116,000.

West Coast Region. The Asset Purchase Agreements for the Long Beach, El Segundo, Encina, and San Diego gas turbine generating facilities provide that Southern California Edison, or SCE, and San Diego Gas & Electric, or SDG&E, retain liability, and indemnify the Company, for existing soil and groundwater contamination that exceeds remedial thresholds in place at the time of closing. The Company and its business partner conducted Phase I and Phase II Environmental Site Assessments at each of these sites for purposes of identifying such existing contamination and provided the results to the sellers. SCE and SDG&E have agreed to address contamination identified by these studies and are undertaking corrective action at the Encina and San Diego gas turbine generating sites. Spills and releases of various substances have occurred at these sites since the Company established the historical baseline, all of which have been, or will be, completely remediated. An oil leak in 2002 from underground piping at the El Segundo Generating Station contaminated soils adjacent to and underneath the Unit 1 and 2 powerhouse. The Company excavated and disposed of contaminated soils that could be removed in accordance with existing laws. Following the Company's formal request, the Los Angeles Regional Water Quality Control Board, or LARWQCB, will allow contaminated soils to remain underneath the building foundation until the building is demolished.

A diesel fuel spill to on-site surface containment occurred at the Cabrillo Power II LLC Kearny Combustion Turbine facility (San Diego) in February 2003. Emergency response and subsequent remediation activities were completed. Confirmation sampling for the site was completed in 2004 and submitted to the San Diego County Department of Environmental Health. Three San Diego Combustion Turbine facilities, formerly operating pursuant to land leases with the U.S. Navy, are currently being decommissioned with equipment being removed from the sites and remediation activities occurring where necessary. All remedial activities are being completed pursuant to the requirements of the U.S. Navy and the San Diego County Department of Environmental Health. Remediation activities were completed in 2004 at the Naval Training Center and North Island facilities. At the 32nd Street Naval Station facility, additional contamination delineation is necessary and additional unquantified remediation in inaccessible areas may be required in the future.

International Environmental Matters

Most of the foreign countries in which we own or may acquire or develop independent power projects have environmental and safety laws or regulations relating to the ownership or operation of electric power generation facilities. These laws and regulations, like in the U.S., are constantly evolving, and have a significant impact on international wholesale power producers. In particular, our international power generation facilities will likely be affected by emissions limitations and operational requirements imposed by the Kyoto Protocol, which is an international treaty related to greenhouse gas emissions which entered into force on February 16, 2005, and country-based restrictions pertaining to global climate change concerns.

We retain appropriate advisors in foreign countries and seek to design our international asset management strategy to comply with each country's environmental and safety laws and regulations. There can be no assurance that changes in such laws or regulations will not adversely effect our international operations.

Australia. With respect to Australia, climate change is considered a long-term issue (e.g. 2010 and beyond) and the Australian government's response to date has included a number of initiatives, all of which have had no impact or minimal impact on the Company's operations. The Australian government has stated that Australia will achieve its Kyoto Protocol target of 8% below 1990 greenhouse gas emission levels for the 2008 to 2012 reporting period but that Australia will not ratify the Kyoto Protocol. Each Australian state government is considering implementing a number of climate change initiatives that will vary considerably state to state.

The asset purchase documentation for the NRG Flinders assets in South Australia provides protections to buyer with respect to historical soil and ground water contamination. Although NRG Flinders has some ongoing obligations with respect to historic site contamination management at Augusta Power Station, Clause 5 of the Environment Compliance Agreement between the South Australian Minister for Environment and Heritage and NRG Flinders dated September 20, 2000, referred to as the EC Agreement, removed any obligation for clean-up or remediation of existing contamination.

While new legislation on contamination is being introduced in South Australia, with particular emphasis on groundwater contamination (regardless of the existing quality of the groundwater), the Company considers it unlikely that any of the proposed amendments will materially negatively impact NRG Flinders' operations. Specifically, despite the proposed "Soil Contamination Amendments to the Environment Protection Act 1993", Flinders will not be obligated to take any action to clean up or remediate any historical groundwater contamination caused by disposal of ash as a seawater slurry to the ash ponds by virtue of the EC Agreement (referenced above).

NRG Flinders disposes of ash to slurry ponds at Port Augusta in South Australia. At the end of life of the power station, NRG Flinders has an obligation to remediate these ponds in accordance with a plan accepted by the South Australian EPA and confirmed in the EC Agreement. The estimated cost of remediation according to the Plan is AUD 1.7 million. There is no timeline associated with the obligation but the EC Agreement extends to 2025. Under these arrangements, required remediation relates to surface remediation and does not entail any groundwater remediation.

A number of other changes in South Australian legislation are proposed; for example a new Water Quality Policy, which may have some minor implications for the Company's operations (e.g., especially mine operations). The Company continues to be involved in the legislative stakeholder process and does not expect the proposed amendments to have a materially adverse effect on its assets or operations.

MIBRAG/Schkopau, Germany. The Company's facilities in Germany are likely to be impacted by evolving emissions limitations imposed as a result of the ratification of the Kyoto Protocol. The Company expects that CO_2 emissions trading will begin in Germany in 2005. Allocations of allowances have now been made by the government, but are being challenged by most recipients. Irrespective of the final allocation amounts, the Company does not expect the CO_2 trading program to be a material constraint on its business in Germany. In addition, changes to the German Emission Control Directive will result in lower NO_X emission limits for plants firing conventional fuels (Section 13 of the Directive) and co-firing waste products (Section 17 of the Directive). The new regulations will require the Mumsdorf and Deuben Power stations to install additional controls to reduce NO_X emissions in 2006.

The European Union's Groundwater Directive and Mine Wastewater Management Directive are in the rule-making stage with the final outcome still under debate. Given the uncertainty regarding the possible outcome of the debate on these directives, we cannot quantify at this time the possible effect such requirements would have on our future coal mining operations in Germany.

A new law specifically dealing with the relocation of residents of Heuersdorf in the path of the mining plan was enacted by the legislature of Saxony in 2004 and there are numerous potential court challenges still outstanding in this process. We cannot predict the outcome of these actions at this time. MIBRAG continues its political and legal work in an effort to obtain a favorable resolution.

The supply contracts under which MIBRAG mines lignite from the Profen mine expire on December 31, 2021. The contracts under which MIBRAG mines lignite from the Schleenhain mine expire in 2041. At the end of each mine's productive lifetime, MIBRAG will be required to reclaim certain areas. MIBRAG accrues for these eventual expenses and estimates the cost of the final reclamation to approach €175 million in the instance of the Schleenhain mine and €132 million for Profen.

Enfield Energy Centre Limited, United Kingdom. The first phase of Europe's CO_2 emissions trading scheme, or EU ETS, beginning in 2005, also affects our assets in the U.K. Participants will be required to surrender emissions allowances equal to the amount of CO_2 they have emitted in each year of the scheme. Allowances will be tradable and a market has already developed in this product. For the U.K. it is not yet possible to quantify the possible effect of this scheme on our operations because final installation level details for the scheme have yet to be released. The second phase of the program will run between 2008 and 2012 and may be extended to cover other GHGs. Additionally, the integrated pollution prevention and control directive, or IPPC, which sets out a framework for the environmental regulation of industrial activities, will be implemented in March 2006. As Enfield Energy Centre is a latest design combined cycle gas turbine, implementing this directive is not expected to require any major changes or expenditures.

Risks Related to NRG Energy, Inc.

Future decreases in gas prices may adversely impact our financial performance.

Certain of our facilities, particularly our coal generation assets, are currently benefiting from higher electricity prices in their respective markets as a result of high gas prices compared to historical levels. Gas-fired facilities set the marginal cost of energy in most of our domestic markets. A decrease in gas prices may lead to a corresponding decrease in electricity prices in these markets, which could materially and adversely impact our financial performance.

Our revenues are unpredictable because most of our power generation facilities operate, wholly or partially, without long-term power purchase agreements. Further, because wholesale power prices are subject to significant volatility, the revenues that we generate are subject to significant fluctuations.

Most of our facilities operate as "merchant" facilities without long-term agreements. An oversupply of generating capacity has depressed wholesale power prices in many regions of the country and increased the difficulty of obtaining long-term contracts. Without the benefit of long-term power purchase agreements, we cannot be sure that we will be able to sell any or all of the power generated by our facilities at commercially attractive rates or that our facilities will be able to operate profitably. This could lead to future impairments of our property, plant and equipment or to the closing of certain of our facilities resulting in economic losses and liabilities.

We sell all or a portion of the energy, capacity and other products from many of our facilities to wholesale power markets, including energy markets operated by independent system operators, or ISOs, or regional transmission organizations, or RTOs. The prices of energy products in those markets are influenced by many factors outside of our control, including fuel prices, transmission constraints, supply and demand, weather, economic conditions and the rules, regulations and actions of the ISOs or RTOs and state and federal regulators. In addition, unlike most other commodities, electric power can only be stored on a very limited basis and generally must be produced concurrently with its use. As a result, the wholesale power markets are subject to significant and unpredictable price fluctuations over relatively short periods.

Competition in wholesale power markets may have a material adverse effect on our results of operations and cash flows.

We have numerous competitors in all aspects of our business, and additional competitors may enter the industry. Our wholesale energy operations compete with other providers of electric energy in the procurement of fuel and transportation services, and the sale of capacity, energy and related products. In order to successfully compete, we seek to aggregate fuel supplies at competitive prices from different sources and locations and to efficiently utilize transportation services from third-party pipelines, railways and other fuel transporters and transmission services from electric utilities.

We also compete against other energy merchants on the basis of our relative skills, financial position and access to credit sources. Energy customers, wholesale energy suppliers and transporters often seek financial guarantees and other assurances that their energy contracts will be satisfied. As a result, our business is constrained by our liquidity, our access to credit and the reduction in market liquidity. Other companies with which we compete may have greater resources in these areas.

Other factors may contribute to increased competition in wholesale power markets. The future of the wholesale power generation industry is unpredictable, but may include consolidation within the industry, the sale, bankruptcy or liquidation of certain competitors, the re-regulation of certain markets or a long-term reduction in new investment into the industry. New capital and competitors have entered the industry in the last three years, including financial investors who perceive that asset values may have bottomed out at levels below their true replacement value. A number of generation facilities in the United States are now in the hands of lenders. Under any scenario, we anticipate that we will continue to face competition from numerous companies in the industry. We anticipate that FERC will continue its efforts to facilitate the competitive energy marketplace throughout the country on several fronts but particularly by encouraging utilities to voluntarily participate in RTOs or ISOs.

Many companies in the regulated utility industry, with which the wholesale power industry is closely linked, are also restructuring or reviewing their strategies. Several of those companies are discontinuing their unregulated activities, seeking to divest their unregulated subsidiaries or attempting to have their regulated subsidiaries acquire assets out of their or other companies' unregulated subsidiaries. This may lead to increased competition between the regulated utilities and the unregulated power producers within certain markets.

A substantial portion of our historical cash flow has been derived from a CDWR contract in California and we do not expect to be able to enter into comparable agreements beyond 2004.

In March 2001, certain affiliates of West Coast Power entered into a contract with the California Department of Water Resources, or CDWR, pursuant to which the affiliates agreed to sell up to 2,300 MW from January 1, 2002 through December 31, 2004, any of which may be resold by the CDWR to utilities such as Southern California Edison Company, PG&E Corp. and San Diego Gas and Electric Company. This contract contributed $108.6 million for the year ended December 31, 2004 and $102.6 million for the full year 2003 to our reported equity earnings in West Coast Power, which were decreased by the non-cash impact of fresh start accounting of $115.8 million for the year ended December 31, 2004 and $8.8 million for the period December 6, 2003 through December 31, 2003. West Coast Power made distributions to NRG Energy of $114.2 million for the year ended December 31, 2004 and $122.2 million during calendar year 2003. The contract and the corresponding earnings and cash flow terminated on December 31, 2004. The CDWR contract accounted for a majority of West Coast Power's revenues during these periods. Beginning January 2005, all of the West Coast Power assets have been negotiated and will operate under reliability must-run, or RMR, agreements. In January 2005, the El Segundo generating facility entered into a tolling arrangement for its entire gross generating capacity of 670 MW commencing May 1, 2005 and extending through December 31, 2005. During the term of this agreement, the purchaser will be entitled to primary energy dispatch rights for the facility's generating capacity. The agreement is subject to the amendment of the El Segundo RMR agreement to switch to RMR Condition I and to otherwise allow the purchaser to exercise its primary dispatch rights under this agreement while preserving Cal ISO's ability to call on the El Segundo facility as a reliability resource under the RMR agreement, if necessary.

Construction, expansion, refurbishment and operation of power generation facilities involve significant risks that cannot always be covered by insurance or contractual protections and could have a material adverse effect on our revenues and results of operations.

Many of our facilities are old. Newer plants owned by our competitors are often more efficient than our aging plants, which may put some of our plants at a competitive disadvantage. Over time, our plants may be squeezed out of their markets, or be unable to compete, because of the construction of new, more efficient plants. Older equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to keep it operating at optimum efficiency. This equipment is also likely to require periodic upgrading and improvement. Any unexpected failure, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures could result in reduced profitability. In addition, if we make any "major modifications" to our power generation facilities, as defined under the new source review provisions of the federal Clean Air Act, we may be required to install "best available control technology" or to achieve the "lowest achievable emissions rate." Any such modifications would likely result in substantial additional capital expenditures.

In general, environmental laws and regulations, particularly with respect to air emissions, are becoming more stringent, which may require us to install expensive plant upgrades and/or restrict or modify our operations to meet more stringent standards. An example of this is RGGI, the regional greenhouse gas initiative in the Northeast, discussed previously in the Northeast section under Regional U.S. Regulatory Initiatives. There are many key unknowns with respect to this initiative, including the applicable baseline, initial allocations, required emissions reductions, availability of offsets, the extent to which states will adopt the program, and the timing for implementation. There can be no assurance at this time that a carbon dioxide cap-and-trade program, if implemented by the states in which we operate, would not have a material adverse effect on our operations in this region.

We cannot predict the level of capital expenditures that will be required due to frequently changing environmental and safety laws and regulations, deteriorating facility conditions and unexpected events (such as natural disasters or terrorist attacks). The unexpected requirement of large capital expenditures could have a material adverse effect on our financial performance and condition. Further, the construction, expansion, modification and refurbishment of power generation facilities involve many risks, including:

- interruptions to dispatch at our facilities;
- supply interruptions;
- work stoppages;
- labor disputes;
- weather interferences;
- unforeseen engineering, environmental and geological problems; and
- unanticipated cost overruns.

The ongoing operation of our facilities involves all of the risks described above, as well as risks relating to the breakdown or failure of equipment or processes, performance below expected levels of output or efficiency and the inability to transport our product to our customers in an efficient manner due to a lack of transmission capacity. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance, warranties or performance guarantees may not be adequate to cover our lost revenues, increased expenses or liquidated damages payments should we experience equipment breakdown or non-performance by contractors. Any of these risks could cause us to operate below expected capacity or availability levels, which in turn could result in lost revenues, increased expenses, higher maintenance costs and penalties.

We are exposed to the risk of fuel and fuel transportation cost increases and volatility and interruption in fuel supply because some of our facilities do not have long-term natural gas, coal or liquid fuel supply agreements.

Most of our domestic natural gas-, coal- and oil-fired power generation facilities purchase their fuel requirements under short-term contracts or on the spot market. Although we attempt to purchase fuel based on our known fuel requirements, we still face the risks of supply interruptions and fuel price volatility as fuel deliveries may not exactly match energy sales due in part to our need to prepurchase fuel inventories for reliability and dispatch requirements. The price we can obtain for the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel costs. This may have a material adverse effect on our financial performance. Moreover, changes in market prices for natural gas, coal and oil may result from the following:

- weather conditions;
- seasonality;
- demand for energy commodities and general economic conditions;

- disruption of electricity, gas or coal transmission or transportation, infrastructure or other constraints or inefficiencies;
- additional generating capacity;
- availability of competitively priced alternative energy sources;
- availability and levels of storage and inventory for fuel stocks;
- natural gas, crude oil, refined products and coal production levels;
- the creditworthiness or bankruptcy or other financial distress of market participants;
- changes in market liquidity;
- natural disasters, wars, embargoes, acts of terrorism and other catastrophic events; and
- federal, state and foreign governmental regulation and legislation.

The volatility of fuel prices could materially and adversely affect our financial results and operations.

The quality of fuel that we rely on at certain of our coal plants may not be available at times.

Our plant operating characteristics and equipment often dictate the specific fuel quality to be combusted. The availability and price of specific fuel qualities may vary due to supplier financial or operational disruptions, transportation disruptions and force majeure. At times, coal of specific quality may not be available at any price, or we may not be able to transport such coal to our facilities on a timely basis. In such case, we may not be able to run a coal facility even if it would be profitable. Operating a coal plant with lesser quality coal can lead to emission problems. If we had contracted the power from the facility, we could be required to supply or purchase power from alternate sources, perhaps at a loss. This could have a material adverse impact on the financial results of specific plants and on our results of operations.

We often rely on single suppliers and at times we rely on single customers at our facilities, exposing us to significant financial risks if either should fail to perform their obligations.

We often rely on a single contracted supplier for the provision of transportation of fuel and other services required for the operation of our facilities. If these suppliers cannot perform, we utilize the marketplace to provide these services. At times, we rely on a single customer or a few customers to purchase all or a significant portion of a facility's output, in some cases under long-term agreements that provide the support for any project debt used to finance the facility. For the year ended December 31, 2004, we derived 49.8% of our revenues from majority-owned operations from four customers: NYISO accounted for 28.5%, ISO New England accounted for 9.1%, National Electricity Market Management Co. Ltd (Australia) accounted for 6.8% and Vattenfall Europe (Germany) accounted for 5.4%. For the period December 6, 2003 through December 31, 2003, we derived 39.0% of our revenues from majority-owned operations from two customers: NYISO accounted for 26.5% and ISO New England accounted for 12.5%. During the period January 1, 2003 through December 5, 2003, we derived 33.4% of our revenues from majority-owned operations from NYISO. During 2002, we derived approximately 26.0% of our revenues from majority-owned operations from NYISO. The failure of any supplier or customer to fulfill its contractual obligations to a facility could have a material adverse effect on such facility's financial results. Consequently, the financial performance of any such facility is dependent on the credit quality of, and continued performance by, suppliers and customers.

Our operations are subject to hazards customary to the power generation industry. We may not have adequate insurance to cover all of these hazards.

Our operations are subject to many hazards associated with the power generation industry, which may expose us to significant liabilities for which we may not have adequate insurance coverage. Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks such as earthquake, flood, lightning, hurricane and wind, hazards, such as fire, explosion, collapse and machinery failure, are inherent risks in our operations. These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, including for environmental cleanup costs, personal injury and property damage and fines and/or penalties. We maintain an amount of insurance protection that we consider adequate, but we cannot assure you that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. A successful claim for which we are not fully insured could hurt our financial results and materially harm our financial condition. Further, due to rising insurance costs and changes in the insurance markets, we cannot assure you that insurance coverage will continue to be available at all or at rates or on terms similar to those presently available to us.

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

We are exposed to market risks through our power marketing business, which involves the sale of energy, capacity and related products and procurement of fuel, transmission services and emission allowances. These market risks include, among other risks, volatility arising from the timing differences associated with buying fuel, converting fuel into energy and delivering the energy to a buyer. We seek to manage this volatility by entering into forward and other contracts that hedge our exposure for our net transactions. The effectiveness of our hedging strategy may be dependent on the amount of collateral available to enter into these hedging contracts, and liquidity requirements may be greater than we anticipate or are able to meet. Without a sufficient amount of working capital to post as collateral in support of performance guarantees or as cash margin, we may not be able to effectively manage price volatility. Factors which could lead to an increase in our required collateral include volatile commodity prices, adverse changes in our industry, credit rating downgrades and the secured nature of our Amended Credit Facility. Under certain unfavorable commodity price scenarios, it is possible that we could experience inadequate liquidity as a result of the posting of additional collateral.

Further, if our facilities experience unplanned outages, we may be required to procure replacement power in the open market to minimize our exposure to liquidated damages. Without adequate liquidity to post margin and collateral requirements, we may be exposed to significant losses and may miss significant opportunities, and we may have increased exposure to the volatility of spot markets.

The 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 (i) electricity sales from our generation assets, (ii) fuel utilized by those assets and (iii) 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 in accordance with SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149. SFAS No. 133 requires us to record all derivatives on the balance sheet at fair value with changes in the fair value resulting from fluctuations in the underlying commodity prices immediately recognized in earnings, unless the derivative qualifies for hedge accounting treatment. Whether a derivative qualifies for hedge accounting depends upon it meeting specific criteria used to determine if hedge accounting is and will remain appropriate for the term of the derivative. Economic hedges will not necessarily qualify for hedge accounting treatment. As a result, we are unable to predict the impact that our risk management decisions may have on our quarterly operating results or financial position.

The value of our assets is subject to the nature and extent of decommissioning and remediation obligations applicable to us.

Our facilities and related properties may become subject to decommissioning and/or site remediation obligations that may require material unplanned expenditures or otherwise materially affect the value of those assets. While we meet all site remediation obligations currently applicable to our assets (largely through the provision of various forms of financial assurance. See Item 1 — Environmental Matters — Domestic Site Remediation Matters), more onerous obligations apply to sites where a plant is to be dismantled, which could negatively affect our ability to economically undertake power redevelopments or alternate uses at existing power plant sites. Further, laws and regulations may change to impose material additional decommissioning and remediation obligations on us in the future, negatively impacting the value of our assets and/or our ability to undertake redevelopment projects.

Our results are subject to quarterly and seasonal fluctuations.

Our quarterly operating results have fluctuated in the past and will continue to do so in the future as a result of a number of factors, including seasonal variations in demand and corresponding electricity and fuel price volatility and variations in levels of production.

Because we own less than a majority of some of our project investments, we cannot exercise complete control over their operations.

We have limited control over the operation of some project investments and joint ventures because our investments are in projects where we beneficially own less than a majority of the ownership interests. We seek to exert a degree of influence with respect to the management and operation of projects in which we own less than a majority of the ownership interests by negotiating to obtain positions on management committees or to receive certain limited governance rights such as rights to veto significant actions. However, we may not always succeed in such negotiations. We may be dependent on our co-venturers to operate such projects. Our co-venturers may not have the level of experience, technical expertise, human resources management and other attributes necessary to operate these projects optimally. The approval of co-venturers also may be required for us to receive distributions of funds from projects or to transfer our interest in projects.

Our access to the capital markets may be limited.

We may require additional capital from outside sources from time to time. Our ability to arrange financing, either at the corporate level or on a non-recourse project-level basis, and the costs of such capital are dependent on numerous factors, including:

- general economic and capital market conditions;
- covenants in our existing debt and credit agreements;
- credit availability from banks and other financial institutions;
- investor confidence in us, our partners and the regional wholesale power markets;
- our financial performance and the financial performance of our subsidiaries;
- our levels of indebtedness;
- maintenance of acceptable credit ratings;
- cash flow; and
- provisions of tax and securities laws that may impact raising capital.

We may not be successful in obtaining additional capital for these or other reasons. The failure to obtain additional capital from time to time may have a material adverse effect on our business and operations.

Our business is subject to substantial governmental regulation and permitting requirements and may be adversely affected by liability under, or any future inability to comply with, existing or future regulations or requirements.

Our business is subject to extensive foreign, federal, state and local energy, environmental and other laws and regulations. We generally are required to obtain and comply with a wide variety of licenses, permits and other approvals in order to construct, operate or modify our facilities. We may incur significant additional costs because of our need to comply with these requirements. If we fail to comply with these requirements, we could be subject to civil or criminal liability and the imposition of liens or fines. We could also be required to shut down any facilities that do not comply with these requirements. In addition, we are at risk for liability for past, current or future contamination at our former and existing facilities or with respect to off-site waste disposal sites that we have used in our operations. Existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to us or our facilities in a manner that may have a detrimental effect on our business. With the continuing trend toward stricter standards, greater regulation and more extensive permitting requirements, we expect that our environmental expenditures will be substantial in the future.

Our operations are potentially subject to the provisions of various energy laws and regulations, including the Public Utility Holding Company Act of 1935, or PUHCA, the Federal Power Act or FPA, and state and local utility laws and regulations. Under the FPA, FERC regulates our wholesale sales of electric power (other than sales by our qualifying facilities, which are exempt from FERC rate regulation). The ability to sell energy at market-based rates is predicated on the absence of market power in either generation or transmission, the inability to create barriers to entry and the inability to engage in abusive affiliate transactions and filing of certain reports with FERC. The market power analysis includes not only generation and transmission owned by a particular applicant but also assets owned by affiliated companies. Holders of market-based rate authority must comply with obligations imposed by FERC and with certain FERC filing requirements such as the requirement to file quarterly reports detailing wholesale sales. Although a number of our direct and indirect subsidiaries have obtained market-based rate authority from FERC, these authorizations could be revoked if we fail in the future to satisfy the applicable criteria, if FERC modifies the criteria, or if FERC eliminates or further restricts the ability of wholesale sellers to make sales at market-based rates.

In addition, under PUHCA, registered holding companies and their subsidiaries (i.e., companies with 10% or more of their voting securities held by registered holding companies) are subject to extensive regulation by the SEC. We will not be considered a holding company or subject to PUHCA as long as we do not become a subsidiary of another registered holding company and the projects in which we have an interest (1) qualify as a qualifying facility, or QF, under the Public Utility Regulatory Policies Act, or PURPA, (2) obtain and maintain exempt wholesale generator, or EWG, status under Section 32 of PUHCA, (3) obtain and maintain foreign utility company, or FUCO, status under Section 33 of PUHCA, or (4) are subject to another exemption or waiver. If our projects were to cease to be exempt and we were to become subject to SEC and FERC regulation under PUHCA, it would be difficult for us to comply with PUHCA absent a substantial corporate restructuring.

Our business faces regulatory risks related to the market rules and regulations imposed by transmission providers, independent system operators and regional transmission organizations.

We face regulatory risk imposed by the various transmission providers, ISOs and RTOs and their corresponding market rules. These market rules are subject to revisions, and such revisions may not benefit us. Transmission providers, ISOs and RTOs have FERC-approved tariffs that govern access to their transmission system. These tariffs may contain provisions that limit access to the transmission grid or allocate scarce transmission capacity in a particular manner.

We presently operate in the following ISO or RTO markets: California (through the West Coast Power joint venture and individually), New England, New York and PJM (the Pennsylvania, Jersey, Maryland Interconnection). The chief regulatory risk is the lack of, or uncertainty regarding, market mechanisms that effectively compensate generating units for providing reliability services and installed capacity.

Restrictions in transmission access and expansions in the transmission system could reduce revenues.

We are dependent on access to transmission systems to sell our energy. In the northeastern ISO and RTO markets, we have a significant amount of generation located in load pockets. Expansion of the transmission system to reduce or eliminate these load pockets could negatively impact our existing facilities in these areas.

Our facilities located in the Entergy franchise territory face a different transmission risk, in that restrictions on transmission access may limit our ability to sell energy or to service new customers.

We are subject to claims made after the date that we filed for bankruptcy and other claims that were not discharged in the bankruptcy cases, which could have a material adverse effect on our results of operations and profitability.

The nature of our business frequently subjects us to litigation. Many of the largest claims against us prior to the date of the bankruptcy filing were satisfied and discharged in accordance with the terms of the NRG plan of reorganization or the plan of reorganization for certain subsidiaries or in connection with settlement agreements that were approved by the bankruptcy court prior to our emergence from bankruptcy. Circumstances in which pre-bankruptcy filing claims have not been discharged include, among others, where we have agreed with a given claimant to preserve their claims, as well as, potentially, instances where a claimant had no notice of the bankruptcy filing. The ultimate resolution of certain remaining or future claims may have a material adverse effect on our results of operations and profitability. In addition, claims made against subsidiaries that did not file for chapter 11, and claims arising after the date of our bankruptcy filing, were not discharged in the bankruptcy cases. See Item 15 — Note 27 to the Consolidated Financial Statements included in our Annual Report on Form 10-K for the Year ended December 31, 2004, for a description of the significant legal proceedings and investigations in which we are presently involved.

Under the NRG plan of reorganization, we have established disputed claims reserves, which we will utilize to make distributions to holders of disputed claims in our bankruptcy cases as and when their claims are resolved. If these reserves prove inadequate, we will be required to finance any further cash distributions from other resources, and doing so could have a material adverse impact on our financial condition, and, in addition, we could be required to issue new common stock, which would dilute existing shareholders. In particular, the State of California's disputed claims against us are capped at $1.35 billion. There are also a number of private claims springing from the California energy crisis for which there is no cap. We have made no reserves for these claims, because we believe they are without merit; however, if the State of California or these private litigants prevail, then payment of the distributions to which the State of California or these private litigants would be entitled under the NRG plan of reorganization could have a material adverse impact on our financial condition.

Acts of terrorism could have a material adverse effect on our financial condition, results of operations and cash flows.

Our generation facilities and the facilities of third parties on which they rely may be targets of terrorist activities, as well as events occurring in response to or in connection with them, that could cause environmental repercussions and/or result in full or partial disruption of their ability to generate, transmit, transport or distribute electricity or natural gas. Strategic targets, such as energy-related facilities, may be at greater risk of future terrorist activities than other domestic targets. Any such environmental repercussions or disruption could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Our international investments face uncertainties.

We have investments in power projects in Australia, the United Kingdom, Germany and Brazil. International investments are subject to risks and uncertainties relating to the political, social and economic structures of the countries in which we invest. Risks specifically related to our investments in international projects may include:

- fluctuations in currency valuation;
- currency inconvertibility;
- expropriation and confiscatory taxation;
- increased regulation; and
- approval requirements and governmental policies limiting returns to foreign investors.

Cautionary Statement Regarding Forward Looking Information

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The words "believes," "projects," "anticipates," "plans," "expects," "intends," "estimates" and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statement. These factors, risks and uncertainties include, but are not limited to, the factors described under "Risks Related to NRG Energy, Inc." in this Item 1 and to the following:

- Lack of comparable financial data due to adoption of Fresh Start reporting;
- Our ability to successfully and timely close transactions to sell certain of our assets;
- The potential impact of our corporate relocation on workforce requirements including the loss of institutional knowledge and the inability to maintain existing processes;
- Hazards customary to the power production industry and power generation operations such as fuel and electricity price volatility, unusual weather conditions, catastrophic weather-related or other damage to facilities, unscheduled generation outages, maintenance or repairs, unanticipated changes to fossil fuel supply costs or availability due to higher demand, shortages, transportation problems or other developments, environmental incidents, or electric transmission or gas pipeline system constraints and the possibility that we may not have adequate insurance to cover losses as a result of such hazards;
- Our potential inability to enter into contracts to sell power and procure fuel on terms and prices acceptable to us;
- The liquidity and competitiveness of wholesale markets for energy commodities;
- Changes in government regulation, including but not limited to the pending changes of market rules, market structures and design, rates, tariffs, environmental laws and regulations and regulatory compliance requirements;
- Price mitigation strategies and other market structures employed by independent system operators, or ISOs, or regional transmission organizations, or RTOs, that result in a failure to adequately compensate our generation units for all of their costs;
- Our ability to borrow additional funds and access capital markets, as well as our substantial indebtedness and the possibility that we may incur additional indebtedness going forward; and
- Significant operating and financial restrictions placed on us contained in the indenture governing our 8% second priority senior secured notes due 2013, our amended and restated credit facility as well as in debt and other agreements of certain of our subsidiaries and project affiliates generally.

Forward-looking statements speak only as of the date they were made, and we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors that could cause our actual results to differ materially from those contemplated in any forward-looking statements included in this Annual Report on Form 10-K should not be construed as exhaustive.

Item 2 — *Properties*

Listed below are descriptions of our interests in facilities, operations and/or projects owned as of December 31, 2004.

Independent Power Production and Cogeneration Facilities

Name and Location of Facility	Purchaser/Power Market	Net Owned Capacity (MW)	NRG'S Percentage Ownership Interest	Fuel Type
Northeast Region:				
Oswego, New York	NYISO	1,700	100%	Oil/Gas
Huntley, New York	NYISO	760	100%	Coal
Dunkirk, New York	NYISO	600	100%	Coal
Arthur Kill, New York	NYISO	842	100%	Gas/Oil
Astoria Gas Turbines, New York	NYISO	600	100%	Gas/Oil
Somerset, Massachusetts	ISO-NE	136	100%	Coal/Oil
Middletown, Connecticut	ISO-NE	786	100%	Oil/Gas/Jet Fuel
Montville, Connecticut	ISO-NE	498	100%	Oil/Gas/Diesel
Devon, Connecticut	ISO-NE	401	100%	Gas/Oil/Jet Fuel
Norwalk Harbor, Connecticut	ISO-NE	353	100%	Oil
Connecticut Jet Power, Connecticut	ISO-NE	127	100%	Jet Fuel
Indian River, Delaware	PJM	784	100%	Coal/Oil
Vienna, Maryland	PJM	170	100%	Oil
Conemaugh, Pennsylvania	PJM	64	4%	Coal/Oil
Keystone, Pennsylvania	PJM	63	4%	Coal/Oil
South Central Region:				
Big Cajun II, Louisiana*	SERC-Entergy	1,489	86%	Coal
Big Cajun I, Louisiana	SERC-Entergy	458	100%	Gas/Oil
Bayou Cove, Louisiana	SERC-Entergy	320	100%	Gas
Sterlington, Louisiana	SERC-Entergy	202	100%	Gas
West Coast Region:				
El Segundo Power, California	Cal ISO	335	50%	Gas
Encina, California	Cal ISO	483	50%	Gas/Oil
Long Beach Generating, California**	Cal ISO	265	50%	Gas
San Diego Combustion Turbines, CA	Cal ISO	85	50%	Gas/Oil
Saguaro Power Co., Nevada***	WECC	53	50%	Gas/Oil
Chowchilla, California	Cal ISO	49	100%	Gas
Red Bluff, California	Cal ISO	45	100%	Gas
Other North America:				
Audrain***	MAIN	640	100%	Gas
Rockford I, Illinois	MAIN	342	100%	Gas

Name and Location of Facility	Purchaser/Power Market	Net Owned Capacity (MW)	NRG'S Percentage Ownership Interest	Fuel Type
Rockford II, Illinois	MAIN	171	100%	Gas
Rocky Road Power, Illinois	PJM	175	50%	Gas
Ilion, New York	NYISO	60	100%	Gas/Oil
Dover, Delaware	PJM	106	100%	Gas/Coal/Oil
James River***	SERC — TVA	55	50%	Coal
Paxton Creek Cogeneration	PJM	12	100%	Gas
Other — 3 projects***	Various	30	Various	Various
Australia:				
Flinders, South Australia	South Australian Pool	760	100%	Coal
Gladstone Power Station, Queensland	Enertrade/Boyne Smelters	630	38%	Coal
Other International:				
Europe:				
Enfield Energy Centre, UK***	UK Electricity Grid	95	25%	Gas
Schkopau Power Station, Germany	Vattenfall Europe	400	42%	Coal
MIBRAG mbH, Germany****	ENVIA/MIBRAG Mines	119	50%	Coal
Brazil:				
Itiquira Energetica, Brazil***	COPEL	154	99%	Hydro
NEO Corporation, Various	Various	41	Various	Various

* Units 1 and 2 owned 100%, Unit 3 owned 58%

** Retired effective January 1, 2005

*** May sell or dispose of in 2005

**** Primarily a coal mining facility

Thermal Energy Production and Transmission Facilities and Resource Recovery Facilities

Name and Location of Facility	Customers	Net Owned Capacity*	NRG's Percentage Ownership Interest	Fuel Type
Non-Generation Facilities:				
NRG Energy Center Minneapolis, Minnesota	Approx. 100 steam customers and 45 chilled water customers	Steam: 1,203 mm Btu/hr. (353 MWt) Chilled water: 41,630 tons (146 MWt)	100%	Gas/Oil
NRG Energy Center San Francisco, California	Approx. 170 steam customers	Steam: 482 mm Btu/hr. (141 MWt)	100%	Gas
NRG Energy Center Harrisburg, Pennsylvania	Approx. 270 steam customers and 3 chilled water customers	Steam: 440 mm Btu/hr. (129 MWt) Chilled water: 2,400 tons (8 MWt)	100%	Gas/Oil
NRG Energy Center Pittsburgh, Pennsylvania	Approx. 25 steam and 25 chilled water customers	Steam: 266 mm Btu/hr. (78 MWt) Chilled water: 12,580 tons (44 MWt)	100%	Gas/Oil
NRG Energy Center San Diego, California	Approx. 20 chilled water customers	Chilled water: 7,425 tons (26 MWt)	100%	Gas
NRG Energy Center St. Paul, Minnesota	Rock-Tenn Company	Steam: 430 mm Btu/hr. (126 MWt)	100%	Coal/Gas/Oil
Camas Power Boiler Washington	Georgia-Pacific Corp.	Steam: 200 mm Btu/hr. (59 MWt)	100%	Biomass
NRG Energy Center Dover, Delaware	Kraft Foods, Inc.	Steam: 190 mm Btu/hr. (56 MWt)	100%	Coal
NRG Energy Center Bayport, Minnesota	Andersen Corporation and Minnesota Correctional Facility	Steam: 200 mm Btu/hr. (59 MWt)	100%	Coal/Gas/Propane

* Thermal production and transmission capacity is based on 1,000 Btus per pound of steam production or transmission capacity. The unit mmBtu is equal to one million Btus.

Name and Location of Facility	Customers	Net Owned Capacity	NRG'S Percentage Ownership Interest
Alternative Energy:			
Resource Recovery Facilities			
Newport, Minnesota	Ramsey and Washington Counties	MSW: 1,500 tons/day	100%
Elk River, Minnesota	Anoka, Hennepin, and Sherburne Counties; Tri-County Solid Waste Management Commission	MSW: 1,275 tons/day	85%

Other Properties

In addition to the above, we lease our corporate offices at 211 Carnegie Center, Princeton, New Jersey 08540 and various other office spaces. We also own interests in other construction projects in various states of completion, as well as other properties not used for operational purposes.

Item 3 — *Legal Proceedings*

California Wholesale Electricity Litigation and Related Investigations

People of the State of California ex. rel. Bill Lockyer, Attorney General, v. Dynegy, Inc. et al., **U.S. District Court, Northern District of California, Case No. C-02-01854 VRW; U.S. Court of Appeals for the Ninth Circuit, Case No. 02-16619.** This action was filed in state court on March 11, 2002, against us, Dynegy, Dynegy Power Marketing, Inc., Xcel Energy, West Coast Power, or WCP, and WCP's four operating subsidiaries. Through our subsidiary, NRG West Coast LLC, we are a 50 percent beneficial owner with Dynegy of West Coast Power, which owns, operates, and markets the power of four California plants. Dynegy and its affiliates and subsidiaries are responsible for gas procurement and marketing and trading activities on behalf of West Coast Power. The complaint alleges that the defendants violated state unfair competition law by selling ancillary services to the state independent system operator, and subsequently selling the same capacity into the spot market. It seeks injunctive relief as well as restitution, disgorgement and unspecified civil penalties. On April 17, 2002, the defendants removed the case to the U.S. District Court for the Northern District of California in San Francisco. In a March 25, 2003, opinion, the court dismissed the Attorney General's action against Dynegy and us with prejudice, finding it was barred by the filed-rate doctrine and preempted by federal law. On July 6, 2004, the U.S. Court of Appeals for the Ninth Circuit rejected the Attorney General's appeal. Rehearing was sought and rejected on October 29, 2004. On January 27, 2005, the Attorney General filed a petition for writ of certiorari to the U.S. Supreme Court.

Public Utility District of Snohomish County v. Dynegy Power Marketing, Inc et al., **Case No. 02-CV-1993 RHW, U.S. District Court, Southern District of California (part of MDL 1405).** This action was filed against us, Dynegy, Xcel Energy and several other market participants on July 15, 2002. The complaint alleges violations of state anti-trust and unfair competition laws by means of price fixing, restriction of supply, and other market "gaming" activities. After the action was transferred to the U.S. District Court for the Southern District of California in San Diego and made a part of the Multi-District Litigation, or MDL, proceeding described below, it was dismissed on the grounds of federal preemption and filed-rate doctrine. The plaintiffs filed a notice of appeal and on September 10, 2004, the U.S. Court of Appeals for the Ninth Circuit affirmed the District Court's dismissal on the same legal grounds. On November 5, 2004, the plaintiff filed a petition for writ of certiorari to the U.S. Supreme Court and on February 22, 2005, the Supreme Court issued an order requesting the views of the U.S. Solicitor General on the petition.

***In re: Wholesale Electricity Antitrust Litigation,* MDL 1405, U.S. District Court, Southern District of California.** The cases included in this proceeding are as follows:

> ***Pamela R Gordon, on Behalf of Herself and All Others Similarly Situated v Reliant Energy, Inc. et al.,* Case No. 758487, Superior Court of the State of California, County of San Diego** (filed on November 27, 2000). ***Ruth Hendricks, On Behalf of Herself and All Others Similarly Situated and On Behalf of the General Public v. Dynegy Power Marketing, Inc. et al.,* Case No. 758565, Superior Court of the State of California, County of San Diego** (filed November 29, 2000). ***The People of the State of California, by and through San Francisco City Attorney Louise H. Renne v. Dynegy Power Marketing, Inc. et al.,* Case No. 318189, Superior Court of California, San Francisco County** (filed January 18, 2001). ***Pier 23 Restaurant, A California Partnership, On Behalf of Itself and All Others Similarly Situated v PG&E Energy Trading et al.,* Case No. 318343, Superior Court of California, San Francisco County** (filed January 24, 2001). ***Sweetwater Authority, et al. v. Dynegy, Inc. et al.,* Case No. 760743, Superior Court of California, County of San Diego** (filed January 16, 2001). ***Cruz M Bustamante, individually, and Barbara Matthews, individually, and on behalf of the general public and as a representative taxpayer suit, v. Dynegy Inc. et al., inclusive.* Case No. BC249705, Superior Court of California, Los Angeles County** (filed May 2, 2001).

NRG Energy is a defendant in all of the above referenced cases. Several of WCP's operating subsidiaries are also defendants in the ***Bustamante*** case. The cases allege unfair competition, market manipulation and price fixing and all seek treble damages, restitution and injunctive relief. In December 2002, the U.S. District Court for the Southern District of California issued an opinion finding that federal jurisdiction was absent in the district court, and remanding the cases back to state court. A notice of appeal was filed and on December 8, 2004, the U.S. Court of Appeals for the Ninth Circuit issued its published, unanimous decision affirming the District Court in most respects. On March 5, 2005, the Ninth Circuit denied a petition for rehearing. We anticipate that the cases will be remanded to state court in 2005 at which time the defendants will again raise filed-rate and federal preemption challenges.

"Northern California" cases against various market participants. **T&E Pastorino v. Duke Energy, et al., Case No. 02-CV-2176; RDJ Farms v. Allegheny Energy, et al., Case No. 02-2059; Century Theatres v. Allegheny Energy, et al., Case No. 02-CV-2177; Bronco Don v. Duke Energy, Case No. 02-CV-2178; El Super Burrito v. Allegheny Energy, et al., Case No. 02-CV-2180; Leo's Day & Night Pharmacy, Case No. 02-CV-2181; J&M Karsant V. Duke Energy, Case No. 02-CV-2182. (Part of MDL 1405).** We were not named in any of these cases, but in all of them, either WCP or one or more of its operating subsidiaries as well as Dynegy are named as defendants. These cases all allege violations of state unfair competition law. Dynegy's counsel is representing both Dynegy and the WCP subsidiaries in these cases with each side responsible for half of the defense costs. These cases all were removed to federal court and denied remand to state court. In late August 2003, the defendants' motions to dismiss were granted in these various cases. On February 25, 2005, the U.S. Court of Appeals for the Ninth Circuit approved the district court decision to dismiss the case.

***Bustamante v. McGraw-Hill Companies, Inc., et al.,* No. BC 235598, California Superior Court, Los Angeles County** (filed November 20, 2002, and amended in 2003). This putative class action alleges that the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades. Named defendants in the suit include several of WCP's operating subsidiaries. Dynegy is defending the WCP subsidiaries pursuant to a limited indemnification agreement. The complaint seeks restitution and disgorgement, civil fines, compensatory and punitive damages, attorneys' fees and declaratory and injunctive relief. Defendant's motion for summary judgment is pending.

Jerry Egger, et al. v. Dynegy, Inc., et al.,* Case No. 809822, Superior Court of California, San Diego County** (filed May 1, 2003). This putative class action alleges violations of California's antitrust law, as well as unlawful and unfair business practices and seeks treble damages, restitution and injunctive relief. The named defendants include WCP and several of its operating subsidiaries. NRG Energy is not named. This case was removed to the U.S. District Court for the Northern District of California, and the defendants have moved to have this case included as Multi-District Litigation along with the above referenced cases. Plaintiffs argued a motion to remand to state court on February 19, 2004, at which time the court stayed the case pending a decision from the U.S. Court of Appeals for the Ninth Circuit in the ***Pastorino appeal, referenced above. Dynegy's counsel is representing Dynegy and WCP and its subsidiaries in this case with each side responsible for half of the defense costs. With the Ninth Circuit's February 25, 2005, decision in the Northern California cases referenced above, a decision on the stay in this case is expected this year.

Texas-Ohio Energy, Inc., on behalf of Itself and all others similarly situated v. Dynegy, Inc. Holding Co., West Coast Power, LLC, et al., **Case No. CIV.S-03-2346 DFL GGH, U.S. District Court, Eastern District of California** (filed November 10, 2003). This putative class action alleges violations of the federal Sherman and Clayton Acts and state antitrust law. In addition to naming WCP and Dynegy, Inc. Holding Co., the complaint names numerous industry participants, as well as "unnamed co-conspirators." The complaint alleges that defendants conspired to manipulate the spot price and basis differential of natural gas with respect to the California market. The complaint seeks unspecified amounts of damages, including a trebling of plaintiff's and the putative class's actual damages. Dynegy is defending WCP pursuant to a limited indemnification agreement.

City of Tacoma, Department of Public Utilities, Light Division, v. American Electric Power Service Corporation, et al., **U.S. District Court, Western District of Washington, Case No. C04-5325 RBL** (filed June 16, 2004). The complaint names over 50 defendants, including WCP's four operating subsidiaries and various Dynegy entities. The complaint also names both us and WCP as "Non-Defendant Co-Conspirators." Plaintiff alleges a conspiracy to violate the federal Sherman Act by withholding power generation from, and/or inflating the apparent demand for power in markets in California and elsewhere. Plaintiff claims damages in excess of $175 million. Dynegy is defending WCP and its subsidiaries pursuant to a limited indemnification agreement.

Fairhaven Power Company v. Encana Corporation, et al., **Case No. CIV-F-04-6256 (OWW/LJO), U.S. District Court, Eastern District of California** (filed September 22, 2004), **Abelman v. Encana, U.S. District Court, Eastern District of California, Case No. 04-CV-6684** (filed December 13, 2004); **Utility Savings v. Reliant, et al., U.S. District Court, Eastern District of California,** (filed November 29, 2004). These putative class actions name WCP and Dynegy Holding Co., Inc. among the numerous defendants. The Complaints allege violations of the federal Sherman Act, and California's antitrust and unfair competition law as well as unjust enrichment. The Complaints seek a determination of class action status, a trebling of unspecified damages, statutory, punitive or exemplary damages, restitution, disgorgement, injunctive relief, a constructive trust, and costs and attorneys' fees. Dynegy is defending WCP pursuant to a limited indemnification agreement.

In Re: Natural Gas Commodity Litigation, **Master File No. 03 CV 6186(VM)(AJP), U.S. District Court, Southern District of New York.** West Coast Power, or WCP, and Dynegy Marketing and Trade are among numerous defendants accused of manipulating gas index publications and prices in violation of the federal Commodity Exchange Act, or CEA, in the following consolidated cases: ***Cornerstone Propane Partners, LP v. Reliant Energy Services, Inc., et al.,*** **Case No. 03 CV 6186** (S.D.N.Y. filed August 18, 2003); ***Calle Gracey v. American Electric Power Co., Inc., et al.,*** **Case No. 03 CV 7750** (S.D.N.Y. filed Oct. 1, 2003); ***Cornerstone Propane Partners, LP v. Coral Energy Resources, LP, et al.,*** **Case No. 03 CV 8320** (S.D.N.Y. filed Oct. 21, 2003); and ***Viola v. Reliant Energy Servs., et al.,*** **Case No. 03 CV 9039** (S.D.N.Y. filed Nov. 14, 2003). Plaintiffs, in their Amended Consolidated Class Action Complaint dated October 14, 2004, allege that the defendants engaged in a scheme to manipulate and inflate natural gas prices. The plaintiffs seek class action status for their lawsuit, unspecified actual damages for violations of the CEA and costs and attorneys' fees. Dynegy Marketing and Trade is defending WCP in these proceedings pursuant to a limited indemnification agreement.

ABAG Publicly Owned Energy Resources v. Sempra Energy, et al., Alameda County Superior Court, Case No. RG04186098, filed November 10, 2004; **Cruz Bustamante v. Williams Energy Services, et al., Los Angeles Superior Court, Case No. BC285598,** filed June 28, 2004; **City & County of San Francisco, et al. v. Sempra Energy, et al., San Diego County Superior Court, Case No. GIC832539,** filed June 8, 2004; **City of San Diego v. Sempra Energy, et al., San Diego County Superior Court, Case No. GIC839407,** filed December 1, 2004; **County of Alameda v. Sempra Energy, Alameda County Superior Court, Case**

No. RG041282878, filed October 29, 2004; **County of San Diego v. Sempra Energy, et al., San Diego County Superior Court, Case No. GIC833371,** filed July 28, 2004; **County of San Mateo v. Sempra Energy, et al., San Mateo County Superior Court, Case No. CIV443882,** filed December 23, 2004; **County of Santa Clara v. Sempra Energy, et al., San Diego County Superior Court, Case No. GIC832538,** filed July 8, 2004; **Nurserymen's Exchange, Inc. v. Sempra Energy, et al., San Mateo County Superior Court, Case No. CIV442605,** filed October 21, 2004; **Older v. Sempra Energy, et al., San Diego Superior Court, Case No. GIC835457,** filed December 8, 2004; **Owens-Brockway Glass Container, Inc. v. Sempra Energy, et al., Alameda County Superior Court, Case No. RG0412046,** filed December 30, 2004; **Sacramento Municipal Utility District v. Reliant Energy Services, Inc., Sacramento County Superior Court, Case No. 04AS04689,** filed November 19, 2004; **School Project for Utility Rate Reduction v. Sempra Energy, et al., Alameda County Superior Court, Case No. RG04180958,** filed October 19, 2004; **Tamco, et al. v. Dynegy, Inc., et al., San Diego County Superior Court, Case No. GIC840587,** filed December 29, 2004; **Utility Savings & Refund Services, LLP v. Reliant Energy Services, Inc., et al., U.S. District Court, Eastern District of California, Case No. 04-6626,** filed November 30, 2004.

The defendants in all of the above referenced cases include WCP and various Dynegy entities. NRG Energy is not a defendant. The Complaints allege that defendants attempted to manipulate natural gas prices in California, and allege violations of California's antitrust law, conspiracy, and unjust enrichment. The relief sought in all of these cases includes treble damages, restitution and injunctive relief. The Complaints assert that WCP is a joint venture between Dynegy and NRG Energy, but that Dynegy Marketing and Trade handled all of the administrative services and commodity related concerns of WCP. The cases are presently being consolidated for coordinated pretrial proceedings in San Diego County Superior Court. Dynegy is defending WCP pursuant to a limited indemnification agreement.

NRG Bankruptcy Cap on California Claims

On November 21, 2003, in conjunction with confirmation of the NRG plan of reorganization, we reached an agreement with the Attorney General and the State of California, generally, whereby for purposes of distributions, if any, to be made to the State of California under the NRG plan of reorganization, the liquidated amount of any and all allowed claims shall not exceed $1.35 billion in the aggregate. The agreement neither affects our right to object to these claims on any and all grounds nor admits any liability whatsoever. We further agreed to waive any objection to the liquidation of these claims in a non-bankruptcy forum having proper jurisdiction.

Investigations

FERC — California Market Manipulation

The FERC conducted an "Investigation of Potential Manipulation of Electric and Natural Gas Prices," which involved hundreds of parties, including our affiliate, West Coast Power, or WCP, and substantial discovery. In June 2001, FERC initiated proceedings related to California's demand for $8.9 billion in refunds from power sellers who allegedly inflated wholesale prices during the energy crisis. After two administrative law judge opinions and a March 26, 2003, FERC Order adopting in part and modifying in part the last of the two opinions, Dynegy, we and the WCP entities engaged in extensive settlement negotiations with FERC Staff; the People of the State of California *ex rel.* Bill Lockyer, Attorney General; the California Public Utility Commission, or CPUC staff; the California Department of Water Resources acting through its Electric Power Fund, the California Electricity Oversight Board; PG&E; Southern California Edison Company; and San Diego Gas and Electric Company. The parties entered into a definitive, comprehensive settlement, which FERC approved on October 25, 2004, (the FERC Settlement).

As part of the FERC Settlement, WCP placed into escrow for distribution to California energy consumers a total of $22.5 million, which includes the $3 million settlement with FERC respecting trading techniques, announced on January 20, 2004. In addition, WCP agreed to forego: (1) past due receivables from the California Independent System Operator and the California Power Exchange related to the settlement period; and (2) natural gas cost recovery claims against the settling parties related to the settlement period. In exchange, the various California settling parties agreed to forego: (1) all claims relating to refunds or other monetary damages for sales of electricity during the settlement period; (2) claims alleging that WCP received unjust or unreasonable rates for the sale of electricity during the settlement period; and (3) FERC dismissed numerous investigations respecting market transactions. For a two year period following FERC's acceptance of the settlement agreement, WCP will retain an independent engineering company to perform semi-annual audits of the technical and economic basis, justification and rationale for outages that occurred at its California generating plants during the previous six month period, and to have the results of such audits provided to the FERC Office of Market Oversight and Investigation without any prior review by WCP.

WCP previously established significant reserves on its balance sheet and will not incur any further loss associated with the FERC Settlement. We will pay no cash from corporate funds, nor will the FERC Settlement have any direct impact on our profit and loss statement.

Other FERC Proceedings

There are a number of additional, related proceedings in which WCP subsidiaries are parties, which are either pending before FERC or on appeal from FERC to various U.S. Courts of Appeal. These cases involve, among other things, allegations of physical withholding, a FERC-established price mitigation plan determining maximum rates for wholesale power transactions in certain spot markets, and the enforceability of, and obligations under, various contracts with, among others, the California Independent System Operator and the State of California and certain of its agencies and departments.

California Attorney General

The California Attorney General has undertaken an investigation entitled "In the Matter of the Investigation of Possibly Unlawful, Unfair, or Anti-Competitive Behavior Affecting Electricity Prices in California." In this connection, the Attorney General has issued subpoenas to Dynegy, served interrogatories on Dynegy and us, and informally requested documents and conducted interviews with Dynegy and Dynegy employees as well as us and our employees. We responded to the interrogatories in the summer of 2002, and again on September 3, 2002. We have also produced a large volume of documentation relating to the West Coast Power subsidiaries.

***Electricity Consumers Resource Council v. Federal Energy Regulatory Commission,* Docket No. 03-1449.** On December 19, 2003, the Electricity Consumers Resource Council, or ECRC, appealed to the U.S. Court of Appeals for the District of Columbia Circuit a 2003 FERC decision approving the implementation of a demand curve for the New York installed capacity, or ICAP, market. ECRC claims that the implementation of the ICAP demand curve violates section 205 of the Federal Power Act because it constitutes unreasonable ratemaking. On December 3, 2004, the Company filed a brief opposing the ECRC request.

***Consolidated Edison Co. of New York v. Federal Energy Regulatory Commission,* Docket No. 01-1503.** Consolidated Edison and others petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of certain FERC orders in which FERC refused to order a re-determination of prices in the New York Independent System Operator, or NYISO, operating reserve markets for the period January 29, 2000, to March 27, 2000. On November 7, 2003, the Court issued a decision which found that the NYISO's method of pricing spinning reserves violated the NYISO tariff. The Court also required FERC to determine whether the exclusion from the non-spinning market of a generating facility known as Blenheim-Gilboa and resources located in western New York also constituted a tariff violation and/or whether these exclusions enabled NYISO to use its Temporary Extraordinary Procedure, or TEP, authority to require refunds. On March 4, 2005, FERC issued an order stating that no refunds would be required for the tariff violation associated with the pricing of spinning reserves. In the order, FERC also stated that the exclusion of the Blenheim-Gilboa facility and western reserves from the non-spinning market was not a market flaw and NYISO was correct not to use its TEP authority to revise the prices in this market. Motions for rehearing of the Order must be filed by April 3, 2005. If the March 4, 2005 order is reversed and refunds are required, NRG entities which may be affected include NRG Power Marketing, Inc., Astoria Gas Turbine Power LLC and Arthur Kill Power LLC.

Although non-NRG-related entities would share responsibility for payment of any such refunds under the petitioners' theory the cumulative exposure to our above-listed entities could exceed $23 million.

Connecticut Light & Power Company v. NRG Power Marketing, Inc., **Docket No. 3:01-CV-2373 (AWT), U.S. District Court, District of Connecticut** (filed on November 28, 2001). Connecticut Light & Power Company, or CL&P, sought recovery of amounts it claimed it was owed for congestion charges under the terms of an October 29, 1999, contract between the parties. CL&P withheld approximately $30 million from amounts owed to NRG Power Marketing, Inc., or PMI, and PMI counterclaimed. CL&P filed its motion for summary judgment to which PMI filed a response on March 21, 2003. By reason of the stay issued by the bankruptcy court, the court has not ruled on the pending motion. On November 6, 2003, the parties filed a joint stipulation for relief from the stay in order to allow the proceeding to go forward that was promptly granted. PMI cannot estimate at this time the overall exposure for congestion charges for the full term of the contract.

Connecticut Light & Power Company v. NRG Energy, Inc., **Federal Energy Regulatory Commission Docket No. EL03-10-000-Station Service Dispute** (filed October 9, 2002); **Binding Arbitration.** On July 1, 1999, Connecticut Light & Power Company, or CL&P, and the Company agreed that we would purchase certain CL&P generating facilities. The transaction closed on December 14, 1999, whereupon NRG Energy took ownership of the facilities. CL&P began billing NRG Energy for station service power and delivery services provided to the facilities and NRG Energy refused to pay asserting that the facilities self-supplied their station service needs. On October 9, 2002, Northeast Utilities Services Company, on behalf of itself and CL&P, filed a complaint at FERC seeking an order requiring NRG Energy to pay for station service and delivery services. On December 20, 2002, FERC issued an Order finding that at times when NRG Energy is not able to self-supply its station power needs, there is a sale of station power from a third-party and retail charges apply. CL&P renewed its demand for payment which was again refused by NRG Energy. In August 2003, the parties agreed to submit the dispute to binding arbitration. The parties each selected one respective arbitrator. A neutral arbitrator cannot be selected until the party-appointed arbitrators have been given a mutually agreed upon description of the dispute, which has yet to occur. Once the neutral arbitrator is selected, a decision is required within 90 days unless otherwise agreed by the parties. The potential loss inclusive of amounts paid to CL&P and accrued could exceed $6 million.

The State of New York and Erin M. Crotty, as Commissioner of the New York State Department of Environmental Conservation v. Niagara Mohawk Power Corporation et al., **U.S. District Court for the Western District of New York, Civil Action No. 02-CV-002S.** In January 2002, the New York State Department of Environmental Conservation, or NYSDEC, sued Niagara Mohawk Power Corporation, or NiMo, and us in federal court in New York. The complaint asserted that projects undertaken at our Huntley and Dunkirk plants by NiMo, the former owner of the facilities, required preconstruction permits pursuant to the Clean Air Act and that the failure to obtain these permits violated federal and state laws. On January 11, 2005, we reached agreement with the State of New York and the NYSDEC to settle this matter. The settlement requires the reduction of sulfur dioxide (SO_2) by over 86 percent and nitrogen oxide by over 80 percent in aggregate at the Huntley and Dunkirk plants. To do so, units 63 and 64 at Huntley will be retired after receiving the appropriate regulatory approvals. Units 65 and 66 will be retired eighteen months later. We also agreed to limits on the transfer of certain federal SO_2 allowances. We are not subject to any penalty as a result of the settlement. Through the end of the decade, we expect that our ongoing compliance with the emissions limits set out in the settlement will be achieved through capital expenditures already planned. This includes conversion to low sulfur western coal at the Huntley and Dunkirk plants that will be completed by spring 2006.

Niagara Mohawk Power Corporation v. NRG Energy, Inc., Huntley Power, LLC, and Dunkirk Power, LLC, **Supreme Court, State of New York, County of Onondaga, Case No. 2001-4372** (filed on July 13, 2001). NiMo filed suit in state court in New York seeking a declaratory judgment with respect to its obligations to indemnify us under the asset sales agreement. We asserted that NiMo is obligated to indemnify us for any related compliance costs associated with resolution of the above referenced NYSDEC enforcement action. On October 18, 2004, the parties reached a confidential settlement.

Niagara Mohawk Power Corporation v. Dunkirk Power LLC, NRG Dunkirk Operations, Inc., Huntley Power LLC, NRG Huntley Operations, Inc., Oswego Power LLC and NRG Oswego Operations, Inc., **Supreme Court, Erie County, Index No. 1-2000-8681 — Station Service Dispute** (filed October 2, 2000). NiMo seeks to recover damages less payments received through the date of judgment, as well as any additional amounts due and owing, for electric service provided to the Dunkirk Plant after September 18, 2000. NiMo claims that we failed to pay retail tariff amounts for utility services commencing on or about June 11, 1999, and continuing to September 18, 2000, and thereafter. NiMo alleged breach of contract, suit on account, violation of statutory duty and unjust enrichment claims. Prior to trial, the parties entered into a Stipulation and Order filed August 9, 2002, consolidating this action with two other actions against the Huntley and Oswego subsidiaries, both of which cases assert the same claims and legal theories. On October 8, 2002, a Stipulation and Order was filed staying this action pending submission to FERC of some or all of the disputes in the action. The potential loss inclusive of amounts paid to NiMo and accrued is approximately $23.2 million.

Niagara Mohawk Power Corporation v. Huntley Power LLC, NRG Huntley Operations, Inc., NRG Dunkirk Operations, Inc., Dunkirk Power LLC, Oswego Harbor Power LLC, and NRG Oswego Operations, Inc., **Case Filed November 26, 2002 in Federal Energy Regulatory Commission Docket No. EL 03-27-000.** This is the companion action to the above referenced action filed by NiMo at FERC asserting the same claims and legal theories. On November 19, 2004, FERC denied NiMo's petition and ruled that the Huntley, Dunkirk and Oswego plants could net their service station obligations over a 30 calendar day period from the day NRG Energy acquired the facilities. In addition, FERC ruled that neither NiMo nor the New York Public Service Commission could impose a retail delivery charge on the NRG facilities because they are interconnected to transmission and not to distribution. NiMo filed a motion for rehearing, on which FERC has not ruled.

U.S. Environmental Protection Agency Request for Information under Section 114 of the Clean Air Act. On January 27, 2004, Louisiana Generating, LLC and Big Cajun II received a request under Section 114 of the federal Clean Air Act from U.S. EPA Region 6 seeking information primarily relating to physical changes made at Big Cajun II. Louisiana Generating, LLC and Big Cajun II submitted several responses to the EPA. On February 15, 2005, Louisiana Generating, LLC received a Notice of Violation alleging violations of the New Source Review provisions of the Clean Air Act from 1998 through the Notice of Violation date. We cannot predict the outcome of this matter at this time.

Itiquira Energetica, S.A. Our Brazilian project company, Itiquira Energetica S.A., the owner of a 156 MW hydro project in Brazil, is in arbitration with the former EPC contractor for the project, Inepar Industria e Construcoes, or "Inepar." The dispute was commenced by Itiquira in September of 2002 and pertains to certain matters arising under the former EPC contract. Itiquira seeks U.S. $40 million and asserts that Inepar breached the contract and caused damages to Itiquira by (i) failing to meet milestones for substantial completion; (ii) failing to provide adequate resources to meet such milestones; (iii) failing to pay subcontractors amounts due; and (iv) being insolvent. Inepar seeks U.S. $10 million and alleges that Itiquira breached the contract and caused damages to Inepar by failing to recognize events of force majeure as grounds for excused delay and extensions of scope of services and material under the contract. An expert investigation was ordered by an arbitration panel to cover technical and accounting issues and expert testimony was presented at two subsequent hearings. Final written arguments from the parties were submitted on January 28, 2005. The court of arbitration is expected to issue a decision by the close of the second quarter of 2005.

CFTC Trading Inquiry. On July 1, 2004, the CFTC filed a civil complaint against us in Minnesota federal district court, alleging false reporting of natural gas trades from August 2001 to May 2002, and seeking an injunction against future violations of the Commodity Exchange Act. On July 23, 2004, we filed a motion with the bankruptcy court to enforce the injunction provisions of the NRG plan of reorganization against the CFTC. Thereafter, we filed with the Minnesota federal district court a motion to dismiss. On November 17, 2004, a Bankruptcy Court hearing was held on the CFTC's motion to reinstate its expunged bankruptcy claim, and on our motion to enforce the injunction contained in our plan of reorganization in order to preclude the CFTC from continuing its Minnesota federal court action. On December 6, 2004, a federal magistrate judge in Minnesota issued a report and recommendation that our motion to dismiss be granted by the district court. On March 16, 2005, the federal district court in Minnesota adopted the magistrate judge's report and recommendations and dismissed the case. The Bankruptcy Court has yet to schedule for a hearing or rule on the CFTC's pending motion to reinstate its expunged claim.

Additional Litigation

In addition to the foregoing, we are parties to other litigation or legal proceedings. See "Market Developments" in the various regions in Item 1 — Business — Power Generation for additional discussion on regulatory legal proceedings.

The Company believes that it has valid defenses to the legal proceedings and investigations described above and intends to defend them vigorously. However, litigation is inherently subject to many uncertainties. There can be no assurance that additional litigation will not be filed against the Company or its subsidiaries in the future asserting similar or different legal theories and seeking similar or different types of damages and relief. Unless specified above, the Company is unable to predict the outcome these legal proceedings and investigations may have or reasonably estimate the scope or amount of any associated costs and potential liabilities. An unfavorable outcome in one or more of these proceedings could have a material impact on the Company's consolidated financial position, results of operations or cash flows. The Company also has indemnity rights for some of these proceedings to reimburse the Company for certain legal expenses and to offset certain amounts deemed to be owed in the event of an unfavorable litigation outcome.

Disputed Claims Reserve

As part of the NRG plan of reorganization, we have funded a disputed claims reserve for the satisfaction of certain general unsecured claims that were disputed claims as of the effective date of the plan. Under the terms of the plan, to the extent such claims are resolved now that we have emerged from bankruptcy, the claimants will be paid from the reserve on the same basis as if they had been paid out in the bankruptcy. That means that their allowed claims will be reduced to the same recovery percentage as other creditors would have received and will be paid in pro rata distributions of cash and common stock. We believe we have funded the disputed claims reserve at a sufficient level to settle the remaining unresolved proofs of claim we received during the bankruptcy proceedings. However, to the extent the aggregate amount of these payouts of disputed claims ultimately exceeds the amount of the funded claims reserve, we are obligated to provide additional cash, notes and common stock to the claimants. We will continue to monitor our obligation as the disputed claims are settled. If excess funds remain in the disputed claims reserve after payment of all obligations, such amounts will be reallocated to the creditor pool. We have contributed common stock and cash to an escrow agent to complete the distribution and settlement process. Since we have surrendered control over the common stock and cash provided to the disputed claims reserve, we recognized the issuance of the common stock as of December 6, 2003 and removed the cash amounts from our balance sheet. Similarly, we removed the obligations relevant to the claims from our balance sheet when the common stock was issued and cash contributed.

Item 4 — *Submission of Matters to a Vote of Security Holders*

No matters were considered during the fourth quarter of 2004.

PART II

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

Market Information and Holders

In connection with the consummation of our reorganization, on December 5, 2003, all shares of our old common stock were canceled and 100,000,000 shares of new common stock of NRG Energy were distributed pursuant to such plan in accordance with Section 1145 of the bankruptcy code to the holders of certain classes of claims. We received no proceeds from such issuance. A certain number of shares of common stock were issued and placed in the Disputed Claims Reserve for distribution to holders of disputed claims as such claims are resolved or settled. See Item 3 — Legal Proceedings — Disputed Claims Reserve. In the event our disputed claims reserve is inadequate, it is possible we will have to issue additional shares of our common stock to satisfy such pre-petition claims or contribute additional cash proceeds. Our authorized capital stock consists of 500,000,000 shares of NRG Energy common stock and 10,000,000 shares of preferred stock. A total of 4,000,000 shares of our common stock are available for issuance under our long-term incentive plan. We have also filed with the Secretary of State of Delaware a Certificate of Designation of our 4% Convertible Perpetual Preferred Stock, or Preferred Stock.

Our common stock is listed on the New York Stock Exchange and has been assigned the symbol: NRG. We have submitted to the New York Stock Exchange our annual certificate from our Chief Executive Officer certifying that he is not aware of any violation by us of New York Stock Exchange corporate governance listing standards. The high and low sales prices, as well as the closing price for our common stock on a per share basis for 2004 and the period December 6, 2003 to December 31, 2003 are set forth below:

Common Stock Price	Fourth Quarter 2004	Third Quarter 2004	Second Quarter 2004	First Quarter 2004	For the Period December 6 - December 31, 2003
High	$36.18	$28.43	$24.80	$22.50	$23.05
Low	$26.00	$24.10	$19.17	$18.10	$18.10
Closing	$36.05	$26.94	$24.80	$22.20	$21.90

NRG Energy had 87,041,935 shares outstanding as of December 31, 2004. As of March 10, 2005, there were 11,182 common shareholders of record.

Dividends

We have not declared or paid dividends on our common stock and the amount of dividends is currently limited by our credit agreements.

Recent Sale of Unregistered Securities; Repurchase of Common Stock

Upon emergence from chapter 11, investment partnerships managed by MatlinPatterson LLC, or MatlinPatterson, owned approximately 21.5 million (21.5%) of our common shares. On December 21, 2004, using existing cash we purchased 13 million shares of common stock from MatlinPatterson at a purchase price of $31.16 per share. In addition to a reduction in total shares of common stock outstanding by 13 million, the share repurchase resulted in (i) the reduction of MatlinPatterson's share ownership to less than 10% from the prior 21.5%, (ii) termination of MatlinPatterson's registration rights, and (iii) resignation from our Board of Directors of three directors affiliated with MatlinPatterson. Our Board's Governance and Nominating Committee is in the process of identifying appropriate independent directors to fill the vacancies.

The following table summarizes the stock repurchased by NRG Energy.

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares that May Yet Be Purchased Under the Plans
December 27, 2004	13,000,000*	$31.16	none	N/A

* 13,000,000 shares were purchased other than through a publicly announced plan. The purchase was made in a negotiated transaction.

Redemption and Repurchase of Second Priority Notes

Proceeds from the sale of the Preferred Stock were used to redeem $375.0 million of our Second Priority Notes on February 4, 2005. In January 2005 and in March 2005, we used existing cash to purchase, at market prices, $25 million and $15.8 million, respectively, in face value of our Second Priority Notes. These notes were assumed by NRG Energy and therefore remain outstanding.

Securities Authorized for Issuance Under Equity Compensation Plans

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by security holders	1,904,026	$22.34	2,053,294*
Equity compensation plans not approved by security holders	—	n/a	—
Total	1,904,026	$22.34	2,053,294*

* The NRG Energy, Inc. Long-Term Incentive Plan became effective upon our emergence from bankruptcy. The Long-Term Incentive Plan, which was adopted in connection with the NRG plan of reorganization, was approved by our stockholders on August 4, 2004. The Long-Term Incentive Plan provides for grants of stock options, stock appreciation rights, restricted stock, performance awards, deferred stock units and dividend equivalent rights. Our directors, officers and employees, as well as other individuals performing services for, or to whom an offer of employment has been extended by us, are eligible to receive grants under the Long-Term Incentive Plan. A total of 4,000,000 shares of our common stock are available for issuance under the Long-Term Incentive Plan. The purpose of the Long-Term Incentive Plan is to promote our long-term growth and profitability by providing these individuals with incentives to maximize stockholder value and otherwise contribute to our success and to enable us to attract, retain and reward the best available persons for positions of responsibility. The Compensation Committee of our Board of Directors administers the Long-Term Incentive Plan. There were 2,053,294 and 3,367,249 shares of common stock remaining available for grants of stock options under our Long-Term Incentive Plan as of December 31, 2004 and 2003, respectively.

Item 6 — *Selected Financial Data*

The following table presents our selected financial data. The data included in the following table has been restated to reflect the assets, liabilities and results of operations of certain projects that have met the criteria for treatment as discontinued operations. For additional information refer to Item 15 — Note 6 to the Consolidated Financial Statements. This historical data should be read in conjunction with the Consolidated Financial Statements and the related notes thereto in Item 15 and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7. Due to the adoption of Fresh Start reporting as of December 5, 2003, the Successor Company's post Fresh Start balance sheet and statement of operations have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of Fresh Start reporting.

	Reorganized NRG		Predecessor Company			
	Year Ended December 31, 2004	December 6 - December 31, 2003	January 1 - December 5, 2003	Year Ended December 31, 2002	2001	2000
	(In thousands, except per share amounts)					
Revenues from majority-owned operations	$2,361,424	$ 138,490	$ 1,798,387	$ 1,938,293	$ 2,085,350	$1,664,980
Corporate relocation charges	16,167	—	—	—	—	—
Reorganization, restructuring and impairment charges	31,271	2,461	435,400	2,563,060	—	—
Fresh start reporting adjustments	—	—	(4,118,636)	—	—	—
Legal settlement	—	—	462,631	—	—	—
Total operating costs and expenses	1,962,309	122,328	(1,475,523)	4,321,385	1,703,531	1,308,589
Write downs and losses on equity method investments	(16,270)	—	(147,124)	(200,472)	—	—
Income/(loss) from continuing operations	162,145	11,405	2,949,078	(2,788,452)	210,502	149,729
Income/(loss) from discontinued operations, net	23,472	(380)	(182,633)	(675,830)	54,702	33,206
Net income/(loss)	185,617	11,025	2,766,445	(3,464,282)	265,204	182,935
Income/(loss) from continuing operations per weighted average share — basic and diluted	$ 1.62	$ .11				
Total assets	7,830,028	9,244,987	N/A	10,896,851	12,915,222	5,986,289
Long-term debt, including current maturities	$3,766,118	$4,129,011	N/A	$ 7,782,648	$ 6,857,055	$3,194,340

The following table provides the detail of our revenues from majority-owned operations:

	Reorganized NRG		Predecessor Company			
	Year Ended December 31, 2004	December 6 - December 31, 2003	January 1 - December 5, 2003	Year Ended December 31, 2002	2001	2000
			(In thousands)			
Energy and energy-related	$1,378,490	$ 78,018	$ 992,626	$1,183,514	$1,376,044	$1,091,115
Capacity	612,294	39,955	565,965	553,321	490,315	405,697
Alternative energy	175,715	12,064	115,911	97,712	161,845	92,671
O & M fees	20,852	1,135	12,942	14,413	15,789	10,073
Other	174,073	7,318	110,943	89,333	41,357	65,424
Total revenues from majority-owned operations	$2,361,424	$138,490	$1,798,387	$1,938,293	$2,085,350	$1,664,980

Energy and energy-related revenue consists of revenues received from third parties for sales in the day-ahead and real-time markets, as well as bilateral sales. In addition, this category includes day-ahead and real-time operating revenues.

Capacity revenue consists of revenues received from a third party at either the market or negotiated contract rates for making installed generation capacity available in order to satisfy system integrity and reliability requirements. In addition, capacity revenues includes revenues received under tolling arrangements which entitle third parties to dispatch our facilities and assume title to the electrical generation produced from that facility.

Alternative energy revenue consists of revenues received from the sale of steam, hot and chilled water generally produced at a central district energy plant and sold to commercial, governmental and residential buildings for space heating, domestic hot water heating and air conditioning. Alternative energy revenue includes the sale of high-pressure steam produced and delivered to industrial customers that is used as part of an industrial process. In addition, alternative revenue includes revenues received from the processing of municipal solid waste into refuse derived fuel that is sold to a third party to be used as fuel in the generation of electricity.

Operations and management, or O&M, fees consist primarily of revenues received from providing certain unconsolidated affiliates with management and operational services generally under long-term operating agreements.

Other revenues consist of miscellaneous other revenues derived from the sale of natural gas, recovery of incurred costs under reliability agreements and revenues received under leasing arrangements. In addition, we also generate revenues from maintenance, the sale of ancillary services excluding day-ahead and real-time operating revenues and by entering into certain financial transactions. Ancillary revenues are derived from the sale of energy related products associated with the generation of electrical energy such as spinning reserves, reactive power and other similar products. Also included in other revenues are revenues derived from financial transactions (derivatives) relating to the sale of energy or fuel which do not require the physical delivery of the underlying commodity.

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

Overview

NRG Energy, Inc., or "NRG Energy", the "Company", "we", "our", or "us" is a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities, the transacting in and trading of fuel and transportation services and the marketing and trading of energy, capacity and related products in the United States and internationally. We have a diverse portfolio of electric generation facilities in terms of geography, fuel type and dispatch levels. Our principal domestic generation assets consist of a diversified mix of natural gas-, coal- and oil-fired facilities, representing approximately 40%, 31% and 29% of our total domestic generation capacity, respectively. In addition, 23% of our domestic generating facilities have dual or multiple fuel capacity, which allows plants to dispatch with the lowest cost fuel option.

Our two principal objectives are to maximize the operating performance of our entire portfolio, and to protect and enhance the market value of our physical and contractual assets through the execution of asset-based risk management, marketing and trading strategies within well-defined risk and liquidity guidelines. We aggregate the assets in our core regions into integrated businesses to serve the requirements of the load-serving entities in our core markets. Our business involves the reinvestment of capital in our existing assets for reasons of repowering, expansion, environmental remediation, operating efficiency, reliability programs, greater fuel optionality, greater merit order diversity, enhanced portfolio effect or for alternative use, among other reasons. Our business also may involve acquisitions intended to complement the asset portfolios in our core regions, and from time to time we may also consider and undertake other merger and acquisition transactions that are consistent with our strategy.

The wholesale energy industry entered a prolonged slump in 2001, from which it is only beginning to emerge. We expect that generally weak market conditions will continue for the foreseeable future in many U.S. markets. We further expect that the merchant power industry will continue to see corporate restructuring, debt restructuring, and consolidation over the coming years.

Asset Sales. We have substantially completed our divestment of major non-core assets; however, as part of our strategy, we plan to continue the selective divestment of certain non-core assets. We have no current plans to market actively any of our core assets, although our intention to maximize over time the value of all of our assets could lead to additional assets sales.

Discontinued Operations. We have classified certain business operations, and gains/losses recognized on sale, as discontinued operations for projects that were sold or have met the required criteria for such classification pending final disposition. Accounting regulations require that continuing operations be reported separately in the income statement from discontinued operations, and that any gain or loss on the disposition of any such business be reported along with the operating results of such business. Assets classified as discontinued operations on our balance sheet as of December 31, 2004 consist of the McClain project. All other projects have been sold as of December 31, 2004.

Independent Registered Public Accounting Firm; Audit Committee. PricewaterhouseCoopers LLP served as our independent auditors from 1995 through 2003. On May 3, 2004, we announced that PricewaterhouseCoopers LLP had decided not to stand for re-election as our independent auditor for the year ended December 31, 2004. On May 24, 2004 the Audit Committee of our Board of Directors appointed KPMG LLP as our independent registered public accounting firm going forward, and on August 4, 2004 our stockholders ratified the appointment. PricewaterhouseCoopers LLP has consented to the inclusion of their reports for the periods January 1, 2003 to December 5, 2003 and December 6, 2003 to December 31, 2003 and for the year ended December 31, 2002. The Company intends to continue to request the consent of PricewaterhouseCoopers LLP in future filings with the SEC when deemed necessary.

Fresh Start Reporting. In connection with our emergence from bankruptcy, we adopted Fresh Start Reporting on December 5, 2003, in accordance with the requirements of Statement of Position 90-7, *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code"*, or SOP 90-7. The application of SOP 90-7 resulted in the creation of a new reporting entity. Under Fresh Start, our reorganization value was allocated to our assets and liabilities on a basis substantially consistent with purchase accounting in accordance with SFAS No. 141. Accordingly, our assets' recorded values were adjusted to reflect their estimated fair values upon adoption of Fresh Start. Any portion of the reorganization value not attributable to specific assets is an indefinite-lived intangible asset referred to as "reorganization value in excess of value of identifiable assets" and reported as goodwill. We did not record any such amounts. As a result of adopting Fresh Start and emerging from bankruptcy, our historical financial information is not comparable to financial information for periods after our emergence from bankruptcy.

Results of Operations

Upon our emergence from bankruptcy, we adopted the Fresh Start provisions of SOP 90-7. Accordingly, the Reorganized NRG statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of Fresh Start, therefore, the Predecessor Company's and the Reorganized NRG's amounts are discussed separately for comparison and analysis purposes, herein.

The following table shows the percent of total revenue each segment contributes to our total revenue:

Segments	Reorganized NRG				Predecessor Company			
	For the Year Ended December 31, 2004	Percent of Total Revenue	For the Period December 6-December 31, 2003	Percent of Total Revenue	For the Period January 1-December 5, 2003	Percent of Total Revenue	For the Year Ended December 31, 2002	Percent of Total Revenue
	(In thousands)		(In thousands)		(In thousands)		(In thousands)	
Wholesale Power Generation								
Northeast	$1,251,153	53.0%	$ 69,191	50.0%	$ 861,452	47.9%	$ 964,196	49.7%
South Central	418,145	17.6%	26,609	19.2%	356,534	19.8%	388,023	20.0%
West Coast	2,469	0.1%	(268)	(0.2)%	23,956	1.3%	30,796	1.6%
Other North America	105,644	4.5%	5,377	3.9%	85,388	4.8%	81,521	4.2%
Australia	181,065	7.7%	11,947	8.6%	151,494	8.4%	170,761	8.8%
All Other								
Other International	157,220	6.7%	13,082	9.4%	137,384	7.6%	108,379	5.6%
Alternative Energy	65,872	2.8%	3,852	2.8%	60,871	3.4%	69,030	3.6%
Non-Generation	186,425	7.9%	9,860	7.1%	129,063	7.2%	135,403	7.0%
Other	(6,569)	(0.3)%	(1,160)	(0.8)%	(7,755)	(0.4)%	(9,816)	(0.5)%
Total Revenue	$2,361,424	100.0%	$138,490	100.0%	$1,798,387	100.0%	$1,938,293	100.0%

The following table provides operating income by segment for the year ended December 31, 2004.

	Northeast	South Central	West Coast	Other North America	Australia	All Other	Total
				(In thousands)			
Energy revenue	$ 853,454	$219,112	$ 9,276	$ 27,816	$159,381	$109,451	$1,378,490
Capacity revenue	264,624	183,483	(3,709)	84,097	—	83,799	612,294
Alternative revenue	49	—	—	1,748	—	173,918	175,715
O & M fees	—	—	(2)	186	—	20,668	20,852
Other revenue	133,026	15,550	(3,096)	(8,203)	21,684	15,112	174,073
Operating revenues	1,251,153	418,145	2,469	105,644	181,065	402,948	2,361,424
Operating expenses	859,769	294,215	10,842	57,686	161,960	321,104	1,705,576
Depreciation and amortization	72,665	62,458	800	21,842	24,027	27,503	209,295
Corporate relocation charges	11	1	—	—	—	16,155	16,167
Reorganization items	180	976	—	142	—	(14,688)	(13,390)
Restructuring and impairment charges	247	2,909	—	26,505	—	15,000	44,661
Operating income/(loss)	$ 318,281	$ 57,586	$(9,173)	$ (531)	$ (4,922)	$ 37,874	$ 399,115

For the Year Ended December 31, 2004 Compared to the Year Ended December 31, 2003

Net Income/(Loss)

Reorganized NRG

For the year ended December 31, 2004, we recorded net income of $185.6 million, or $1.85 per weighted average share of diluted common stock. These favorable results occurred despite a challenging market environment in 2004. Unseasonably mild weather, high volatility on forward markets and disappointing spot power prices summarize 2004's events. The year started with colder than normal weather arriving in January but unseasonably mild weather characterized the period from March thru December which dampened energy prices in North America. The National Oceanic Atmospheric Agency, or NOAA, has ranked the mean average temperatures over the past 110 years by season for each of the lower 48 states. The year 2004 started with the winter being colder than normal in the east coast followed by a spring, summer and fall which were among the mildest in the last 110 years throughout most of the United States. Although mild weather in the North America market kept spot market on-peak power prices low throughout most of the year, relatively high gas and oil prices kept spark spreads on coal-based assets positive.

The overall perception that there would be significant production losses due to Hurricane Ivan ignited a strong pre-heating season rally in natural gas futures during the early fourth quarter. While power prices tracked changes in natural gas prices, this movement was not one for one. As a result, our spark spreads on coal-based generation increased dramatically with the fall 2004 changes in gas prices. During this period we sold forward 2005 power locking in these spark spreads. Forward power prices have fallen considerably from the highs set in October, and many of those forward sales, which were marked-to-market through earnings, significantly contributed to the $57.3 million unrealized gain recorded in revenue for the year ended December 31, 2004 and as more fully described in Note 16 to the financial statements.

As indicated above, our 2004 results were favorably impacted by the cold weather in January. Additionally, the Northeast's income results for the year were positively impacted by the $57.3 million of unrealized gains associated with forward sale transactions supporting our Northeast assets. The majority of the unrealized gains relate to forward sales of electricity which will be realized in 2005. These gains were offset by our South Central region's results, which were negatively impacted by an unplanned outage in the fourth quarter forcing us to purchase power to meet our contract supply obligations. Impairment charges of $44.7 million negatively impacted net income; of which $26.5 million relates to the Kendall asset. Our results were also favorably impacted by the FERC-approved settlement agreement between NRG Energy and Connecticut Light & Power, or CL&P, and others concerning the congestion and losses obligation associated with a prior standard offer service contract, whereby we received $38.4 million in settlement proceeds in July 2004. The 2004 results were also positively impacted by $159.8 million in equity earnings of unconsolidated affiliates including $68.9 million from our interest in West Coast Power which benefited from warmer than normal temperatures during the year.

During the period December 6, 2003 through December 31, 2003, we recognized net income of $11.0 million or $0.11 per share of common stock. Net income was directly attributable to a number of factors some of which are discussed below. From an overall operational perspective our facilities were profitable during this period. Our results were adversely impacted by our having to continue to satisfy the standard offer service contract that we entered into with CL&P in 2000. As a result of our inability to terminate this contract during our bankruptcy proceeding, we continued to be exposed to losses under this contract. These losses were incurred, as we were unable to satisfy the requirements of this contract at a price/cost below the contracted sales price. Upon our adoption of Fresh Start, we recorded at fair value, all assets and liabilities on our opening balance sheet and accordingly we recorded as an obligation the fair value of the CL&P contract. During the period December 6, 2003 through December 31, 2003, we recognized as revenues the entire fair value of this contract effectively offsetting the actual losses incurred under this contract. The CL&P contract terminated on December 31, 2003.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded net income of $2.8 billion. Net income for the period is directly attributable to our emerging from bankruptcy and adopting the Fresh Start provisions of SOP 90-7. Upon the confirmation of our Plan of Reorganization and our emergence from bankruptcy, we were able to remove significant amounts of long-term debt and other pre-petition obligations from our balance sheet. Accordingly, as part of net income, we recorded a net gain of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) as the impact of our adopting Fresh Start in our statement of operations. $6.0 billion of this amount is directly related to the forgiveness of debt and settlement of substantial amounts of our pre-petition obligations upon our emergence from bankruptcy. In addition to the removal of substantial amounts of pre-petition debt and other obligations from our balance sheet, we also revalued our assets and liabilities to fair value. Accordingly, we substantially wrote down the value of our fixed assets. We recorded a net $1.6 billion charge related to the revaluation of our assets and liabilities within the Fresh Start Reporting adjustment line of our consolidated statement of operations. In addition to our adjustments related to our emergence from bankruptcy, we also recorded substantial charges related to other items such as the settlement of certain outstanding litigation in the amount of $462.6 million, write downs and losses on the sale of equity investments of $147.1 million, advisor costs and legal fees directly attributable to our being in bankruptcy of $197.8 million and $237.6 million of other asset impairment and restructuring costs incurred prior to our filing for bankruptcy. Net income for the period January 1, 2003 through December 5, 2003 was favorably impacted by our not recording interest expense on substantial amounts of corporate level debt while we were in bankruptcy and by the continued favorable results experienced by our equity investments.

Revenues from Majority-Owned Operations

Reorganized NRG

Our revenues from majority-owned operations were $2.4 billion for the year ended December 31, 2004 which included $1.4 billion of energy revenues, $612.3 million of capacity revenues, $175.7 million of alternative energy revenues, $20.8 million of O&M fees and $174.1 million of other revenues, which include $57.3 million of unrealized gains associated with financial sales transactions of electricity, which are marked to market, $22.4 million from ancillary service revenues and the remainder related to financial and physical gas sales and non-cash contract amortization resulting from fresh start accounting and other miscellaneous revenue items.

Revenues from majority-owned operations for the year ended December 31, 2004, were driven primarily by our North American operations, primarily our Northeast facilities. Our wholly-owned domestic Northeast power generation operations significantly contributed to our energy revenues. Our wholly-owned North America assets generated approximately 29.0 million megawatt hours during the year 2004 with the Northeast region representing 45.6% of these megawatt hours. Of the total $1.4 billion in energy revenues, the Northeast region represented 62%. Our energy revenues were favorably impacted by the FERC-approved settlement agreement between us and CL&P and others, whereby we received $38.4 million in settlement proceeds in July 2004. These settlement proceeds are included in the All Other segment in the energy revenue category. South Central's energy revenues are driven by our ability to sell merchant energy, which is dependent upon available generation from our coal-based Louisiana Generating company after serving our co-op customer and long-term customer load obligations. Since our load obligation is primarily residential load, our merchant opportunities are largely available in the off-peak hours of the day. Our Australian operations were favorably impacted by strong market prices driven by gas restrictions in January, record high temperatures in February and March, and favorable foreign exchange movements. Our capacity revenues are largely driven by our Northeast and South Central facilities. Our South Central and New York City assets earned 30% and 26% of our total capacity revenues, respectively. In the Northeast, our Connecticut facilities continue to benefit from the cost-based reliability must-run, or RMR agreements, which were authorized by FERC as of January 17, 2004 and approved by FERC on January 27, 2005. The agreements entitle us to approximately $7.1 million of capacity revenues per month until January 1, 2006, the LICAP implementation date. In the South Central region, our long-term contracts provide for capacity payments. Other North American capacity revenues were generated by our Kendall operation, which had a long-term tolling agreement. During this period we also experienced a favorable impact on our revenues due to the mark-to-market on certain of our derivative contracts wherein we have recognized $57.3 million in unrealized gains. This gain is related to our Northeast assets and is included in Other Revenue. Also included in Other Revenue in the Northeast are the cost reimbursement funds under the RMR agreement for our Connecticut assets. Our revenues during this period include net charges of $35.3 million of non-cash amortization of the fair values of various executory contracts recorded on our balance sheet upon our adoption of the Fresh Start provisions of SOP 90-7 in December 2003.

Our revenues from majority-owned operations were $138.5 million for the period December 6, 2003 through December 31, 2003.

Predecessor Company

Revenues from majority-owned operations were $1.8 billion for the period January 1, 2003 through December 5, 2003 and include $992.6 million of energy revenues, $566.0 million of capacity revenues, $115.9 million of alternative energy, $12.9 million of O&M fees and $110.9 million of other revenues which include financial and physical gas sales, sales from our Schkopau facility and NEPOOL expense reimbursements. Revenues from majority-owned operations during the period ended December 5, 2003, were driven primarily by our North American operations and to a lesser degree by our international operations, primarily Australia. Our domestic Northeast and South Central power generation operations significantly contributed to our revenues due primarily to favorable market prices resulting from strong fuel and electricity prices. Our Australian operations were favorably impacted by foreign exchange rates. During this period we also experienced an unfavorable impact on our revenues due to continued losses on our CL&P standard offer contract and the mark-to-market on certain of our derivatives.

Cost of Majority-Owned Operations

Reorganized NRG

Our cost of majority-owned operations for the year ended December 31, 2004 was $1.5 billion or 63.3% of revenues from majority-owned operations. Cost of majority-owned operations consist of $1.008 billion of cost of energy (primarily fuel and purchased energy costs), or 42.7% of revenues from majority-owned operations and $486.1 million of operating expenses, or 20.6% of revenues from majority-owned operations. Operating expenses consist of $208.5 million of labor related costs, $236.7 million of operating and maintenance costs, $38.2 million of non-income based taxes and $2.9 million of asset retirement obligation accretion.

Cost of Energy

Fuel related costs include $478.3 million in coal costs, $233.0 million in natural gas costs, $104.7 million in fuel oil costs, $38.8 million in transmission and transportation expenses, $100.4 million of purchased energy costs, $35.0 million in other costs and $17.8 million in non-cash SO_2 emission credit amortization resulting from Fresh Start accounting. The Northeast region consumed 50%, 64% and 92% of total coal, natural gas and oil expenditures, respectively. The South Central region, which is comprised mainly of our Louisiana base-loaded coal plant, consumed 32% of our total coal expenditures.

Operating Expenses

Operating expenses related to continuing operations for the year ended December 31, 2004 were $486.1 million or 20.6% of revenues from majority-owned operations. Operating expenses include labor, normal and major maintenance costs, environmental and safety costs, utilities costs, and non-income based taxes. Labor costs include regular, overtime and contract costs at our plants and totaled $208.5 million. The Northeast region, where the majority of our assets reside, represents 52% of total labor costs; Australia represents 18%, while our South Central region represents 11%. Of the total O&M costs, normal and major maintenance at our plants accounted for $176.7 million, or 36.3% of total operating costs. Maintenance costs were largely driven by planned outages across our fleet, and the low-sulfur coal conversion in western New York. The Northeast region represented over half of the normal and major maintenance, with a total of $98.6 million in costs in 2004 while Australia had $38.8 million in normal and major maintenance, or 22%. Operating expenses were positively impacted by a $7 million favorable settlement with a vendor regarding auxiliary power charges. Non-income based taxes totaled $38.2 million net of $34.6 million in property tax credits, primarily associated with an enterprise zone program.

Cost of majority-owned operations was $95.5 million, or 69.0% of revenues from majority-owned operations for the period December 6, 2003 through December 31, 2003. Cost of energy for this period was $62.3 million or 45.0% of revenues from majority-owned operations and operating expenses were $33.2 million, or 24.0% of revenues from majority-owned operations. Labor during this period totaled $11.1 million. Normal and major maintenance was $12 million with 70% of the total normal and major maintenance for this time period coming from our Northeast region.

Predecessor Company

Cost of majority-owned operations was $1.4 billion, or 75.4% of revenues from majority-owned operations for the period January 1, 2003 through December 5, 2003. Cost of majority-owned operations was unfavorably impacted by increased generation in the Northeast region, partially offset by a reduction in trading and hedging activity resulting from a reduction in our power marketing activities. Our international operations were impacted by an unfavorable movement in foreign exchange rates and continued mark-to-market of the Osborne contract at Flinders resulting from lower pool prices.

Depreciation and Amortization

Reorganized NRG

Our depreciation and amortization expense related to continuing operations for the year ended December 31, 2004 was $209.3 million. Depreciation and amortization consists primarily of the allocation of our historical depreciable fixed asset costs over the remaining lives of such property. Upon adoption of Fresh Start, we were required to revalue our fixed assets to fair value and determine new remaining lives for such assets. Our fixed assets were written down substantially upon our emergence from bankruptcy. We also determined new remaining depreciable lives, which are, on average, shorter than what we had previously used primarily due to the age and condition of our fixed assets.

Depreciation and amortization expense for the period December 6, 2003 through December 31, 2003 was $11.8 million. Depreciation and amortization expense consists of the allocation of our newly valued basis in our fixed assets over newly determined remaining fixed asset lives.

Predecessor Company

Our depreciation and amortization expense related to continuing operations for the period January 1, 2003 through December 5, 2003 was $218.8 million. During this period, depreciation expense was unfavorably impacted by the shortening of the depreciable lives of certain of our domestic power generation facilities located in the Northeast region and the impact of recently completed construction projects. The depreciable lives of certain of our Northeast facilities, primarily our Connecticut facilities, were shortened to reflect economic developments in that region. Certain capitalized development costs were written-off in connection with the Loy Yang project resulting in increased expense. Amortization expense increased due to reducing the life of certain software costs.

General, Administrative and Development

Reorganized NRG

Our general, administrative and development costs related to continuing operations for the year ended December 31, 2004 were $211.2 million. Of this total, $111.1 million or 4.7% of revenues from majority-owned operations represents our corporate costs, with the remaining $100.1 million representing costs at our plant operations. Corporate costs are primarily comprised of corporate labor, external professional support, such as legal, accounting and audit fees, and office expenses. Corporate general, administrative and development expenses were negatively impacted this year by increased legal fees, increased audit costs and increased consulting costs due to our Sarbanes Oxley testing and implementation. Plant general, administrative and development costs primarily include insurance and external consulting costs. Plant insurance costs were $40.6 million. Additionally, we recorded $11.7 million in bad debt expense related to notes receivable.

General, administrative and development costs were $12.5 million, or 9.0% of revenues from continuing operations for the period December 6, 2003 to December 31, 2003. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees.

Predecessor Company

Our general, administrative and development costs related to continuing operations for the period January 1, 2003 to December 5, 2003 were $170.3 million or 9.5% of revenues from majority-owned operations. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees.

Other Charges (Credits)

Reorganized NRG

For the year ended December 31, 2004, we recorded other charges of $47.4 million, which consisted of $16.2 million of corporate relocation charges, $13.4 million of reorganization credits and $44.6 million of restructuring and impairment charges.

For the period December 6, 2003 through December 31, 2003 we recorded $2.5 million of reorganization charges.

Predecessor Company

During the period January 1, 2003 to December 5, 2003, we recorded other credits of $3.2 billion, which consisted primarily of $228.9 million related to asset impairments, $462.6 million related to legal settlements, $197.8 million related to reorganization charges and $8.7 million related to restructuring charges. We also incurred a $4.1 billion credit related to Fresh Start adjustments.

Other charges (credits) consist of the following:

	Reorganized NRG		Predecessor Company
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In thousands)		
Corporate relocation charges	$16,167	$ —	$ —
Reorganization items	(13,390)	2,461	197,825
Impairment charges	44,661	—	228,896
Restructuring charges	—	—	8,679
Fresh Start adjustments	—	—	(4,118,636)
Legal settlement	—	—	462,631
Total	$47,438	$2,461	$(3,220,605)

Corporate Relocation Charges

On March 16, 2004, we announced plans to implement a new regional business strategy and structure. The new structure called for a reorganized leadership team and a corporate headquarters relocation to Princeton, New Jersey. The corporate headquarters staff were streamlined as part of the relocation, as functions were either reduced or shifted to the regions. The transition of the corporate headquarters is substantially complete. During the year ended December 31, 2004, we recorded $16.2 million for charges related to our corporate relocation activities, primarily for employee severance and termination benefits and employee related transition costs. These charges are classified separately in our statement of operations, in accordance with SFAS No. 146, *"Accounting for Costs Associated with Exit or Disposal Activities"*. We expect to incur an additional $7.7 million of SFAS No. 146-classified expenses in connection with corporate relocation charges for a total of $23.9 million. Of this total, relocating, recruiting and other employee-related transition costs are expected to be approximately $11.9 million and have been and will continue to be expensed as incurred. These costs and cash payments are expected to be incurred through the second quarter of 2005. Severance and termination benefits of $7.2 million are expected to be incurred through the second quarter of

2005 with cash payments being made through the fourth quarter of 2005. Building lease termination costs are expected to be $4.8 million. These costs are expected to be incurred through the first quarter of 2005 with cash payments being made through the fourth quarter of 2006. Costs not classified separately as relocation charges include rent expense of our temporary office in Princeton, construction costs of our new office and certain labor costs. All costs relating to the corporate relocation that are not classified separately as relocation charges, except for approximately $5.7 million of related capital expenditures will be expensed as incurred and included in general, administrative and development expenses. Cash expenditures for 2004, including capital expenditures, were $22.4 million. We currently estimate total costs associated with the corporate relocation to be approximately $40.0 million.

We recognized a curtailment gain of $750,000 on our defined benefit pension plan in the fourth quarter of 2004, as a substantial number of our current headquarters staff left the Company in this period.

Reorganization Items

For the year ended December 31, 2004, we recorded a net credit of $13.4 million related primarily to the settlement of obligations recorded under Fresh Start. We incurred $7.4 million of professional fees associated with the bankruptcy which offset $20.8 million of credits associated with creditor settlements. For the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, we incurred $2.5 million and $197.8 million, respectively, in reorganization costs. All reorganization costs have been incurred since we filed for bankruptcy in May 2003. The following table provides the detail of the types of costs incurred.

	Reorganized NRG		Predecessor Company
	Year Ended December 31, 2004	For the period December 6 - December 31, 2003	For the period January 1 - December 5, 2003
		(In thousands)	
Reorganization items			
Professional fees	$ 7,383	$2,461	$ 82,186
Deferred financing costs	—	—	55,374
Pre-payment settlement	—	—	19,609
Interest earned on accumulated cash	—	—	(1,059)
Contingent equity obligation	—	—	41,715
Settlement of obligations	(20,773)	—	—
Total reorganization items	$(13,390)	$2,461	$197,825

Impairment Charges

We review the recoverability of our long-lived assets in accordance with the guidelines of SFAS No. 144. As a result of this review, we recorded impairment charges of $44.7 million and $228.9 million for the year ended December 31, 2004 and the period January 1, 2003 through December 5, 2003, respectively, as shown in the table below. Of the $44.7 million total in 2004, Kendall and the Meriden turbine accounted for $26.5 million and $15.0 million, respectively. Both of these charges were based on indicative market valuations. We successfully completed the sale of Kendall in November 2004 and expect to complete the sale of the Meriden turbine in the first quarter of 2005. There were no impairment charges for the period December 6, 2003 through December 31, 2003.

To determine whether an asset was impaired, we compared asset carrying values to total future estimated undiscounted cash flows. Separate analyses were completed for assets or groups of assets at the lowest level for which identifiable cash flows were largely independent of the cash flows of other assets and liabilities. The estimates of future cash flows included only future cash flows, net of associated cash outflows, directly associated with and expected to arise as a result of our assumed use and eventual disposition of the asset. Cash flow estimates associated with assets in service were based on the asset's existing service potential. The cash flow estimates may include probability weightings to consider possible alternative courses of action and outcomes, given the uncertainty of available information and prospective market conditions.

If an asset was determined to be impaired based on the cash flow testing performed, an impairment loss was recorded to write down the asset to its fair value. Estimates of fair value were based on prices for similar assets and present value techniques. Fair values determined by similar asset prices reflect our current estimate of recoverability from expected marketing of project assets. For fair values determined by projected cash flows, the fair value represents a discounted cash flow amount over the remaining life of each project that reflects project-specific assumptions for long-term power pool prices, escalated future project operating costs, and expected plant operation given assumed market conditions.

Impairment charges (credits) included the following asset impairments (realized gains) for the year ended December 31, 2004 and the period January 1, 2003 to December 5, 2003.

Project Name	Project Status	Reorganized NRG Year Ended December 31, 2004	Predecessor Company For the Period January 1 - December 5, 2003	Basis of Impairment Charge
		(In thousands)		
Louisiana Generating LLC	Office building and land being marketed	$ 493	$ —	Estimated market price
New Roads Holding LLC (turbine)	Non-operating asset — abandoned	2,416	—	Projected cash flows
Devon Power LLC	Operating at a loss in 2003	247	64,198	Projected cash flows
Middletown Power LLC	Operating at a loss	—	157,323	Projected cash flows
Arthur Kill Power, LLC	Terminated construction project	—	9,049	Projected cash flows
Langage (UK)	Terminated	—	(3,091)	Estimated market price
Turbines	Sold	—	(21,910)	Realized gain
Berrians Project	Terminated	—	14,310	Realized loss
TermoRio	Terminated	—	6,400	Realized loss
Meriden	Sold	15,000	—	Similar asset prices
Kendall and other expansion projects	Sold	26,505	—	Projected cash flows, sales contracts
Other		—	2,617	
Total impairment charges		$44,661	$228,896	

Restructuring Charges

We incurred $8.7 million of employee separation costs and advisor fees during the period January 1, 2003 until we filed for bankruptcy in May 2003. Subsequent to that date we recorded all advisor fees as reorganization costs.

Fresh Start Adjustments

During the fourth quarter of 2003, we recorded a net credit of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) in connection with fresh start adjustments. Following is a summary of the significant effects of the reorganization and Fresh Start:

	(In millions)
Discharge of corporate level debt	$ 5,162
Discharge of other liabilities	811
Establishment of creditor pool	(1,040)
Receivable from Xcel	640
Revaluation of fixed assets	(1,392)
Revaluation of equity investments	(207)
Valuation of SO_2 emission credits	374
Valuation of out of market contracts, net	(400)
Fair market valuation of debt	108
Valuation of pension liabilities	(61)
Other valuation adjustments	(100)
Total Fresh Start adjustments	3,895
Less discontinued operations	(224)
Total Fresh Start adjustments — continuing operations	$ 4,119

Legal Settlement Charges

During the period January 1, 2003 to December 5, 2003, we recorded $462.6 million of legal settlement charges which consisted of the following. We recorded $396.0 million in connection with the resolution of an arbitration claim asserted by FirstEnergy Corp. As a result of this resolution, FirstEnergy retained ownership of the Lake Plant Assets and received an allowed general unsecured claim of $396.0 million under NRG Energy's Plan of Reorganization. In November 2003, we settled litigation with Fortistar Capital in which Fortistar Capital released us from all litigation claims in exchange for a $60.0 million pre-petition bankruptcy claim and an $8.0 million post-petition bankruptcy claim. We had previously recorded $10.8 million in connection with various legal disputes with Fortistar Capital; accordingly, we recorded an additional $57.2 million during November 2003. In November 2003, we settled our dispute with Dick Corporation in connection with Meriden Gas Turbines LLC through the payment of a general unsecured claim and a post-petition pre-confirmation payment. This settlement resulted in our recording an additional liability of $8.0 million in November 2003.

In August 1995, we entered into a Marketing, Development and Joint Proposing Agreement, or the Marketing Agreement, with Cambrian Energy Development LLC, or Cambrian. Various claims arose in connection with the Marketing Agreement. In November 2003, we entered into a settlement agreement with Cambrian where we agreed to transfer our 100% interest in three gasco projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville) and our 50% interest in two genco projects (MM Phoenix and MM Woodville) to Cambrian. In addition, we paid approximately $1.8 million in settlement of royalties incurred in connection with the Marketing Agreement. We had previously recorded a liability for royalties owed to Cambrian, therefore, we recorded an additional $1.4 million during November 2003.

Other Income (Expense)

Reorganized NRG

During the year ended December 31, 2004, we recorded other expense of $171.9 million. Other expense consisted primarily of $269.4 million of interest expense, $71.6 million of refinancing-related expenses, $1.0 million of minority interest in earnings of consolidated subsidiaries and $16.3 million of write downs and losses on sales of equity method investments, offset by $159.8 million of equity in earnings of unconsolidated affiliates (including $68.9 million from our investment in West Coast Power LLC) and $26.6 million of other income, net.

Other income (expense) for the period December 6, 2003 through December 31, 2003, was an expense of $5.4 million and consisted primarily of $18.9 million of interest expense, partially offset by $13.5 million of equity in earnings of unconsolidated affiliates.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded other expense of $286.9 million. Other expense consisted primarily of $329.9 million of interest expense and $147.1 million of write downs and losses on sales of equity method investments, partially offset by equity in earnings of unconsolidated affiliates of $170.9 million and $19.2 million of other income, net.

Minority Interest in Earnings of Consolidated Subsidiaries

For the year ended December 31, 2004, minority interest in earnings of consolidated subsidiaries was $1.0 million which relates primarily to our ownership interests in Northbrook Energy, LLC and Northbrook New York, LLC, partnerships which hold a portfolio of small hydro projects. For the period December 6, 2003 through December 31, 2003, minority interest in earnings of consolidated subsidiaries was $134,000 and relates primarily to Northbrook New York and Northbrook Energy.

Equity in Earnings of Unconsolidated Affiliates

Reorganized NRG

For the year ended December 31, 2004, we recorded $159.8 million of equity earnings from our investments in unconsolidated affiliates. Our equity in earnings of West Coast Power comprised $68.9 million of this amount with our equity in earnings of Enfield, Mibrag, and Gladstone comprising $28.5 million, $20.9 million, and $17.5 million, respectively. Our investment in West Coast Power generated favorable results due to the pricing under the California Department of Water Resources contract. Additionally, revenues from ancillary services revenue and minimum load cost compensation power positively contributed to West Coast Power's operating results. However, our equity earnings in the project as reported in our results of operations have been reduced by a net $115.8 million to reflect a non-cash basis adjustment for in the money contracts resulting from adoption of Fresh Start.

NRG Energy's equity earnings were also favorably impacted by $23.3 million of unrealized gain related to our Enfield investment. This gain is associated with changes in the fair value of energy-related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

Equity in earnings of unconsolidated affiliates of $13.5 million for the period December 6, 2003 through December 31, 2003 consists primarily of equity earnings from our 50% ownership in West Coast Power of $9.4 million.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded $170.9 million of equity earnings from investments in unconsolidated affiliates. Our 50% investment in West Coast Power comprised $98.7 million of this amount with our investments in the Mibrag, Loy Yang, Gladstone and Rocky Road projects comprising $21.8 million, $17.9 million, $12.4 million and $6.9 million, respectively, with the remaining amounts attributable to various domestic and international equity investments.

Equity in earnings of unconsolidated affiliates consists of the following:

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
West Coast Power	$ 68,895	$ 9,362	$ 98,741	$ 19,044
MIBRAG	20,938	102	21,818	28,750
Enfield	28,505	481	5,975	(6,017)
Gladstone	17,528	997	12,440	7,237
Rocky Road	6,904	305	6,864	6,868
James River	7,750	543	(1,893)	9,713
NRG Saguaro	5,480	617	3,940	4,968
Scudder LA Trust	1,521	150	2,653	1,043
NRG National	846	190	2,010	1,695
MWPC — RDF	200	8	123	259
NRG Cadillac	(421)	(2)	280	195
Central and Eastern European Energy Power Fund	(47)	(22)	(260)	(331)
Loy Yang	—	—	17,924	8,443
Other	1,726	790	286	(12,871)
Total Equity in Earnings of Unconsolidated Affiliates	$159,825	$13,521	$170,901	$ 68,996

Write Downs and Losses on Sales of Equity Method Investments

As part of our periodic review of our equity method investments for impairments, we have taken write downs and losses on sales of equity method investments during the year ended December 31, 2004 of $16.3 million and $147.1 million for the period January 1, 2003 through December 5, 2003. Our Commonwealth Atlantic Limited Partnership (CALP) and James River investments were written down based on indicative market bids. The sale of CALP closed in the fourth quarter of 2004, while the sale agreement for James River has been terminated. There were no write downs and losses on sales of equity method investments for the period December 6, 2003 through December 31, 2003.

Write downs and losses (gains) on sales of equity method investments recorded in the consolidated statement of operations include the following:

	Reorganized NRG	Predecessor Company
	Year Ended December 31, 2004	For the Period January 1 - December 5, 2003
	(In thousands)	
Commonwealth Atlantic Limited Partnership	$ 4,614	$ —
James River Power LLC	7,293	—
NEO Corporation	3,830	—
Calpine Cogeneration	(735)	—
NLGI — Minnesota Methane	—	12,257
NLGI — MM Biogas	—	2,613
Kondapalli	—	(519)
ECKG	—	(2,871)
Loy Yang	1,268	146,354
Mustang	—	(12,124)
Other	—	1,414
Total write downs and losses of equity method investments	$16,270	$147,124

Commonwealth Atlantic Limited Partnership (CALP) — In June 2004, we executed an agreement to sell our 50% interest in CALP. During the third quarter of 2004, we recorded an impairment charge of approximately $3.7 million to write down the value of our investment in CALP to its fair value. The sale closed in November 2004, resulting in net cash proceeds of $14.9 million. Total impairment charges as a result of the sale were $4.6 million.

James River Power LLC — In September 2004, we executed an agreement with Colonial Power Company LLC to sell all of our outstanding shares of stock in Capistrano Cogeneration Company, a wholly-owned subsidiary of NRG Energy which owns a 50% interest in James River Cogeneration Company. During the third quarter of 2004, we recorded an impairment charge of approximately $6.0 million to write down the value of our investment in James River to its fair value. During the fourth quarter of 2004, the sale agreement was terminated. We continue to impair any additional equity earnings based on its fair value. Total impairment charges for 2004 were $7.3 million.

NEO Corporation — On September 30, 2004, we completed the sale of several NEO investments — Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC to Algonquin Power of Canada. The sale also included four wholly-owned NEO subsidiaries (see Item 15 — Note 6). We received cash proceeds of $6.1 million. The sale resulted in a loss of approximately $3.8 million attributable to the equity investment entities sold.

Calpine Cogeneration — In January 2004, we executed an agreement to sell our 20% interest in Calpine Cogeneration Corporation to Calpine Power Company. The transaction closed in March 2004 and resulted in net cash proceeds of $2.5 million and a net gain of $0.2 million. During the second quarter of 2004, we received additional consideration on the sale of $0.5 million, resulting in an adjusted net gain of $0.7 million.

NLGI — Minnesota Methane — We recorded an impairment charge of $12.3 million during 2002 to write-down our 50% investment in Minnesota Methane. We recorded an additional impairment charge of $14.5 million during the first quarter of 2003. These charges were related to a revised project outlook and management's belief that the decline in fair value was other than temporary. In May 2003, the project lenders to the wholly-owned subsidiaries of NEO Landfill Gas, Inc. and Minnesota Methane LLC foreclosed on our membership interest in the NEO Landfill Gas, Inc. subsidiaries and our equity interest in Minnesota Methane LLC. Upon completion of the foreclosure, we recorded a gain of $2.2 million, resulting in a net impairment charge of $12.3 million for the period January 1, 2003 to December 5, 2003. This gain resulted from the release of certain obligations.

NLGI — MM Biogas — We recorded an impairment charge of $3.2 million during 2002 to write-down our 50% investment in MM Biogas. This charge was related to a revised project outlook and management's belief that the decline in fair value was other than temporary. In November 2003, we entered into a sales agreement with Cambrian Energy Development to sell our 50% interest in MM Biogas. We recorded an additional impairment charge of $2.6 million during the fourth quarter of 2003 due to developments related to the sale that indicated an impairment of our book value that was considered to be other than temporary.

Kondapalli — In the fourth quarter of 2002, we wrote down our investment in Kondapalli by $12.7 million due to recent estimates of sales value, which indicated an impairment of our book value that was considered to be other than temporary. On January 30, 2003, we signed a sale agreement with the Genting Group of Malaysia, or Genting, to sell our 30% interest in Lanco Kondapalli Power Pvt Ltd, or Kondapalli, and a 74% interest in Eastern Generation Services (India) Pvt Ltd (the O&M company). Kondapalli is based in Hyderabad, Andhra Pradesh, India, and is the owner of a 368 MW natural gas fired combined cycle gas turbine. In the first quarter of 2003, we wrote down our investment in Kondapalli by $1.3 million based on the final sale agreement. The sale closed on May 30, 2003 resulting in net cash proceeds of approximately $24 million and a gain of approximately $1.8 million, resulting in a net gain of $0.5 million. The gain resulted from incurring lower selling costs than estimated as part of the first quarter impairment.

ECKG — In September 2002, we announced that we had reached agreement to sell our 44.5% interest in the ECKG power station in connection with our Csepel power generating facilities, and our interest in Entrade, an electricity trading business, to Atel, an independent energy group headquartered in Switzerland. The transaction closed in January 2003 and resulted in cash proceeds of $65.3 million and a net loss of less than $1.0 million. In accordance with the purchase agreement, we were to receive additional consideration if Atel purchased shares held by our partner. During the second quarter of 2003, we received approximately $3.7 million of additional consideration, resulting in a net gain of $2.9 million.

Loy Yang — Based on a third party market valuation and bids received in response to marketing Loy Yang for possible sale, we recorded a write down of our investment of approximately $111.4 million during 2002. This write-down reflected management's belief that the decline in fair value of the investment was other than temporary. In May 2003, we entered into negotiations that culminated in the completion of a Share Purchase Agreement to sell 100% of the Loy Yang project. Consequently, we recorded an additional impairment charge of approximately $146.4 million during 2003. In April 2004, we completed the sale of Loy Yang which resulted in net cash proceeds of $26.7 million and a loss of $1.3 million.

Mustang Station — On July 7, 2003, we completed the sale of our 25% interest in Mustang Station, a gas-fired combined cycle power generating plant located in Denver City, Texas, to EIF Mustang Holdings I, LLC. The sale resulted in net cash proceeds of approximately $13.3 million and a net gain of approximately $12.1 million.

Other Income, net

Reorganized NRG

During the year ended December 31, 2004, we recorded $26.6 million of other income, net, consisting primarily of interest income earned on notes receivable and cash balances. For the period December 6, 2003 through December 31, 2003 we recorded other income of $97,000.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded $19.2 million of other income, net. During this period other income, net consisted primarily of interest income earned on notes receivable and cash balances, offset in part by the unfavorable mark-to-market on our corporate level £160 million note that was cancelled in connection with our bankruptcy proceedings.

Interest Expense

Reorganized NRG

Interest expense for the year ended December 31, 2004 was $269.4 million, consisting of interest expense on both our project- and corporate-level interest-bearing debt. Significant amounts of our corporate-level debt were forgiven upon our emergence from bankruptcy and we refinanced significant amounts of our project-level debt with corporate level high yield notes and term loans in December 2003. Also included in interest expense is the amortization of debt financing costs of $9.2 million related to our corporate level debt and $13.3 million of amortization expense related primarily to debt discounts and premiums recorded as part of Fresh Start. Interest expense also includes the impact of any interest rate swaps that we have entered in order to manage our exposure to changes in interest rates.

Interest expense for the period December 6, 2003 through December 31, 2003 of $18.9 million consists primarily of interest expense at the corporate level, primarily related to the Second Priority Notes, term loan facility and revolving line of credit used to refinance certain project-level financings. In addition, interest expense includes the amortization of deferred financing costs incurred as a result of our refinancing efforts and the amortization of discounts and premiums recorded upon the marking of our debt to fair value upon our adoption of the Fresh Start provision of SOP 90-7.

Predecessor Company

Interest expense for the period January 1, 2003 through December 5, 2003 of $329.9 million consisted of interest expense on both our project and corporate level interest bearing debt. In addition, interest expense includes the amortization of debt issuance costs and any interest rate swap termination costs. Interest expense during this period was favorably impacted by our ceasing to record interest expense on debt where it was probable that such interest would not be paid, such as the NRG Energy corporate level debt (primarily bonds) and the NRG Finance Company debt (construction revolver) due to our entering into bankruptcy in May 2003. We did not however cease to record interest expense on the project-level debt outstanding at our Northeast Generating and South Central Generating facilities even though these entities were also in bankruptcy as these claims were deemed to be most likely not impaired and not subject to compromise. We also recorded substantial amounts of fees and costs related to our acquiring a debtor in possession financing arrangement while we were in bankruptcy. In addition, upon our emergence from bankruptcy we wrote off any remaining deferred finance costs related to our corporate and project-level debt including our Northeast and South Central project-level debt as it was probable that they would be refinanced upon our emergence from bankruptcy. Interest expense was unfavorably impacted by an adverse mark-to-market on certain interest rate swaps that we have entered in order to manage our exposure to changes in interest rates. Due to our deteriorating financial condition during such period, hedge accounting treatment was ceased for certain of our interest rate swaps, causing changes in fair value to be recorded as interest expense.

Refinancing Expense

Refinancing expense was $71.6 million for the year ended December 31, 2004. This amount includes $15.1 million of prepayment penalties and a $15.3 million write-off of deferred financing costs related to refinancing certain amounts of our term loans with additional corporate level high yield notes in January 2004 and $13.8 million of prepayment penalties and a $26.8 million write-off of deferred financing costs related to refinancing the senior credit facility in December 2004.

Income Tax Expense

Reorganized NRG

Our income tax provision from continuing operations was $65.1 million for the year ended December 31, 2004 and an income tax benefit of ($0.7) million for the period December 6, 2003 through December 31, 2003. The overall effective tax rate in 2004 and the short period in 2003 was 28.7% and (6.2%), respectively.

The change in our effective tax rate was primarily due to a state tax refund received from Xcel Energy in 2003 and foreign income taxed in jurisdictions with tax rates different from the U.S. statutory rate.

Our net deferred tax assets at December 31, 2004 were offset by a full valuation allowance in accordance with SFAS No. 109. Under SOP 90-7, any future benefits from reducing a valuation allowance from preconfirmation deferred tax assets are required to be reported first as an adjustment of identifiable intangible assets and then as a direct addition to paid in capital versus a benefit on our statement of operations.

The effective tax rate may vary from year to year depending on, among other factors, the geographic and business mix of earnings and losses. These same and other factors, including history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Predecessor Company

Income tax expense for the period January 1, 2003 through December 5, 2003 was $37.9 million. The overall effective tax rate for the period ended December 5, 2003 was 1.3%. The rate is lower than the U.S. statutory rate primarily due to a release in valuation allowance for net operating loss carryforwards that were utilized following our emergence from bankruptcy to offset the current tax on cancellation of debt income.

Income taxes have been recorded on the basis that our U.S. subsidiaries and we would file separate federal income tax returns for the period January 1, 2003 through December 5, 2003. Since our U.S. subsidiaries and we were not included in the Xcel Energy consolidated tax group, each of our U.S. subsidiaries that is classified as a corporation for U.S. income tax purposes filed a separate federal income tax return. It is uncertain if, on a stand-alone basis, we would be able to fully realize deferred tax assets related to net operating losses and other temporary differences, therefore a full valuation allowance has been established.

Income From Discontinued Operations, net of Income Taxes

Reorganized NRG

We classified as discontinued operations the operations and gains/losses recognized on the sale of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. During the year ended December 31, 2004, we recorded income from discontinued operations, net of income taxes, of $23.5 million. During the year ended December 31, 2004 and for the period December 6, 2003 to December 31, 2003, discontinued operations consisted of the results of our NRG McClain LLC, Penobscot Energy Recovery Company, or PERC, Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee, Hsin Yu, LSP Energy (Batesville) and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC). All other discontinued operations were disposed of in prior periods. The $23.5 million income from discontinued operations includes a gain of $22.4 million, net of income taxes of $7.9 million, related primarily to the dispositions of Batesville, Cobee and Hsin Yu.

Discontinued operations for the period December 6, 2003 through December 31, 2003 is comprised of a loss of $0.4 million attributable to the on going operations of our McClain, PERC, Cobee, LSP Energy, Hsin Yu and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC).

Predecessor Company

As of December 5, 2003, we classified as discontinued operations the operations and gains/losses recognized on the sales of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. For the period January 1, 2003 through December 5, 2003, discontinued operations consist of the historical operations and net gains/losses related to our Killingholme, McClain, PERC, Cobee, NEO Landfill Gas, Inc., or NLGI, seven NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC, NEO Tajiguas LLC, NEO Ft. Smith LLC, NEO

Woodville LLC and NEO Phoenix LLC), Timber Energy Resources, Inc., or TERI, Cahua, Energia Pacasmayo, LSP Energy and Hsin Yu projects.

For the period January 1, 2003 through December 5, 2003, the results of operations related to such discontinued operations was a net loss of $182.6 million due to a loss on the sale of our Peru projects, impairment charges of $100.7 million and $23.6 million, respectively, recorded at McClain and NLGI and fresh start adjustments at LSP Energy.

For the Year Ended December 31, 2003 Compared to the Year Ended December 31, 2002

Net Income

Reorganized NRG

During the period December 6, 2003 through December 31, 2003, we recognized net income of $11.0 million or $0.11 per share of common stock. Net income was directly attributable to a number of factors some of which are discussed below. From an overall operational perspective our facilities were profitable during this period. Our results were adversely impacted by our having to continue to satisfy the standard offer service contract that we entered into with Connecticut Light & Power, or CL&P, in 2000. As a result of our inability to terminate this contract during our bankruptcy proceeding, we continued to be exposed to losses under this contract. These losses were incurred, as we were unable to satisfy the requirements of this contract at a price/cost below the contracted sales price. Upon our adoption of Fresh Start, we recorded at fair value all assets and liabilities on our opening balance sheet and accordingly we recorded as an obligation the fair value of the CL&P contract. During the period December 6, 2003 through December 31, 2003, we recognized as revenues the entire fair value of this contract effectively offsetting the actual losses incurred under this contract. The CL&P contract terminated on December 31, 2003.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded net income of $2.8 billion. Net income for the period is directly attributable to our emerging from bankruptcy and adopting the Fresh Start provisions of SOP 90-7. Upon the confirmation of our Plan of Reorganization and our emergence from bankruptcy we were able to remove significant amounts of long-term debt and other pre-petition obligations from our balance sheet. Accordingly, as part of net income, we recorded a net gain of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) as the impact of our adopting Fresh Start in our statement of operations. $6.0 billion of this amount is directly related to the forgiveness of debt and settlement of substantial amounts of our pre-petition obligations upon our emergence from bankruptcy. In addition to the removal of substantial amounts of pre-petition debt and other obligations from our balance sheet, we have also revalued our assets and liabilities to fair value. Accordingly, we have substantially written down the value of our fixed assets. We have recorded a net $1.6 billion charge related to the revaluation of our assets and liabilities within the Fresh Start Reporting adjustment line of our consolidated statement of operations. In addition to our recording adjustments related to our emergence from bankruptcy, we also recorded substantial charges related to other items such as the settlement of certain outstanding litigation in the amount of $462.6 million, write downs and losses on the sale of equity investments of $147.1 million, advisor costs and legal fees directly attributable to our being in bankruptcy of $197.8 million and $237.6 million of other asset impairment and restructuring costs incurred prior to our filing for bankruptcy. Net income for the period January 1, 2003 through December 5, 2003 was favorably impacted by our not recording interest expense on substantial amounts of corporate level debt while we were in bankruptcy and by the continued favorable results experienced by our equity investments.

During the year ended December 31, 2002, we recognized a net loss of $3.5 billion. The loss from continuing operations incurred during 2002 primarily consisted of $2.6 billion of other charges consisting primarily of asset impairments.

Revenues from Majority-Owned Operations

Reorganized NRG

Our operating revenues from majority-owned operations were $138.5 million for the period December 6, 2003 through December 31, 2003.

Predecessor Company

Revenues from majority-owned operations were $1.8 billion for the period January 1, 2003 through December 5, 2003 and include $992.6 million of energy revenues, $566.0 million of capacity revenues, $115.9 million of alternative energy, $12.9 million of O&M fees and $110.9 million of other revenues which include financial and physical gas sales, sales from our Schkopau facility and NEPOOL expense reimbursements. Revenues from majority-owned operations during the period year ended December 5, 2003, were driven primarily by our North American operations and to a lesser degree by our international operations, primarily Australia. Our domestic Northeast and South Central power generation operations significantly contributed to our revenues due primarily to favorable market prices resulting from strong fuel and electricity prices. Our Australian operations were favorably impacted by favorable foreign exchange rates. During this period we also experienced an unfavorable impact on our revenues due to continued losses on our CL&P standard offer contract and the mark-to-market on certain of our derivatives.

Revenues from majority-owned operations were $1.9 billion for the year ended December 31, 2002.

Cost of Majority-Owned Operations

Reorganized NRG

Our cost of majority-owned operations for the period December 6, 2003 through December 31, 2003 was $95.5 million or 69.0% of revenues from majority-owned operations.

Predecessor Company

Cost of majority-owned operations was $1.4 billion, or 75.4% of revenues from majority-owned operations for the period January 1, 2003 through December 5, 2003. Cost of majority-owned operations was unfavorably impacted by increased generation in the Northeast region, partially offset by a reduction in trading and hedging activity resulting from a reduction in our power marketing activities. Our international operations were unfavorably impacted due to an unfavorable movement in foreign exchange rates and continued mark-to-market of the Osborne contract at Flinders resulting from lower pool prices.

Our cost of majority-owned operations related to continuing operations was $1.3 billion for 2002, or 68.7% of revenues from majority-owned operations. Cost of majority-owned operations, consists primarily of cost of energy (primarily fuel costs), labor, operating and maintenance costs and non-income based taxes related to our majority-owned operations. Cost of energy for the year ended December 31, 2002 was $900.9 million or 46.5% of revenue from majority-owned operations.

Depreciation and Amortization

Reorganized NRG

Our depreciation and amortization expense related to continuing operations was $11.8 million for the period December 6, 2003 through December 31, 2003. Depreciation and amortization expense consists of the allocation of our newly valued basis in our fixed assets over newly determined remaining fixed asset lives. As part of adopting the Fresh Start concepts of SOP 90-7, our tangible fixed assets were recorded at fair value as determined by a third party valuation expert who we also consulted with in determining the appropriate remaining lives for our tangible depreciable property. Depreciation expense for this period was based on preliminary depreciable lives and asset balances.

Predecessor Company

Our depreciation and amortization expense related to continuing operations was $218.8 million for the period January 1, 2003 through December 5, 2003 and $207.0 million for the year ended December 31, 2002. During the period January 1, 2003 to December 5, 2003, depreciation expense was unfavorably impacted by the shortening of the depreciable lives of certain of our domestic power generation facilities located in the Northeast region and the impact of completed construction projects. Depreciation and amortization consists of the allocation of our historical depreciable fixed asset costs over the remaining lives of such property as well as the amortization of certain contract based intangible assets.

General, Administrative and Development

Reorganized NRG

Our general, administrative and development costs for the period December 6, 2003 through December 31, 2003 was $12.5 million or 9.0% of revenues from majority-owned operations. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees.

Predecessor Company

Our general, administrative and development costs for the period January 1, 2003 through December 5, 2003 were $170.3 million, or 9.5% of revenues from majority-owned operations. Our general, administrative and development costs for 2002 were $218.9 million, or 11.3% of revenues from majority-owned operations. General, administrative and development costs for the period January 1, 2003 through December 5, 2003 were favorably impacted by decreased costs related to work force reduction efforts, cost reductions due to the closure of certain international offices and reduced legal costs. Outside services also decreased, due to less non-restructuring legal activities.

Other Charges (Credits)

Reorganized NRG

During the period December 6, 2003 through December 31, 2003 we recorded $2.5 million of other charges related to reorganization items.

Predecessor Company

During the period January 1, 2003 to December 5, 2003, we recorded other credits of $3.2 billion, which consisted primarily of $228.9 million related to asset impairments, $462.6 million related to legal settlements, $197.8 million related to reorganization charges and $8.7 million related to restructuring charges. We also incurred a $4.1 billion credit related to Fresh Start adjustments. During 2002, we recorded other charges of $2.6 billion, which consisted primarily of $2.5 billion related to asset impairments and $111.3 million related to restructuring charges.

We review the recoverability of our long-lived assets on a periodic basis and if we determined that an asset was impaired, we compared asset-carrying values to total future estimated undiscounted cash flows. Separate analyses are completed for assets or groups of assets at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The estimates of future cash flows included only future cash flows, net of associated cash outflows, directly associated with and expected to arise as a result of our assumed use and eventual disposition of the asset. Cash flow estimates associated with assets in service are based on the asset's existing service potential. The cash flow estimates may include probability weightings to consider possible alternative courses of action and outcomes, given the uncertainty of available information and prospective market conditions.

If an asset was determined to be impaired based on the cash flow testing performed, an impairment loss was recorded to write down the asset to its fair value. Estimates of fair value were based on prices for similar assets and present value techniques. Fair values determined by similar asset prices reflect our current estimate of recoverability from expected marketing of project assets. For fair values determined by projected cash flows, the fair value represents a discounted cash flow amount over the remaining life of each project that reflects project-specific assumptions for long-term power pool prices, escalated future project operating costs, and expected plant operation given assumed market conditions.

Impairment charges (credits) included the following for the period January 1, 2003 to December 5, 2003 and the year ended December 31, 2002. There were no impairment charges for the period December 6, 2003 through December 31, 2003.

		Predecessor Company		
Project Name	**Project Status**	**For the Period January 1 - December 5, 2003**	**Year Ended December 31, 2002**	**Fair Value Basis**
		(In thousands)		
Devon Power LLC	Operating at a loss	$ 64,198	$ —	Projected cash flows
Middletown Power LLC	Operating at a loss	157,323	—	Projected cash flows
Arthur Kill Power, LLC	Terminated construction project	9,049	—	Projected cash flows
Langage (UK)	Terminated	(3,091)	42,333	Estimated market price/Realized gain
Turbine	Sold	(21,910)	—	Realized gain
Berrians Project	Terminated	14,310	—	Realized loss
Termo Rio	Terminated	6,400	—	Realized loss
Nelson	Terminated	—	467,523	Similar asset prices
Pike	Terminated	—	402,355	Similar asset prices
Bourbonnais	Terminated	—	264,640	Similar asset prices
Meriden	Terminated	—	144,431	Similar asset prices
Brazos Valley	Foreclosure completed in January 2003	—	102,900	Projected cash flows
Kendall and other expansion projects	Terminated	—	55,300	Projected cash flows
Turbines & other costs	Equipment being marketed	—	701,573	Similar asset prices
Audrain	Operating at a loss	—	66,022	Projected cash flows
Somerset	Operating at a loss	—	49,289	Projected cash flows
Bayou Cove	Operating at a loss	—	126,528	Projected cash flows
Other		2,617	28,851	
Total impairment charges (credits)		$228,896	$2,451,745	

Reorganization Items

For the period from December 6, 2003 to December 31, 2003 we incurred $2.5 million in reorganization costs. For the period from January 1, 2003 to December 5, 2003, we incurred $197.8 million in reorganization costs. All reorganization costs have been incurred since we filed for bankruptcy in May 2003. The following table provides the detail of the types of costs incurred (in thousands):

	Reorganized NRG	Predecessor Company
	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In thousands)	
Reorganization items		
Professional fees	$2,461	$ 82,186
Deferred financing costs	—	55,374
Pre-payment settlement	—	19,609
Interest earned on accumulated cash	—	(1,059)
Contingent equity obligation	—	41,715
Total reorganization items	$2,461	$197,825

Restructuring Charges

We incurred $8.7 million of employee separation costs and advisor fees during the period January 1, 2003 until we filed for bankruptcy in May 2003. Subsequent to that date we recorded all advisor fees as reorganization costs. We incurred total restructuring charges of approximately $111.3 million for the year ended December 31, 2002. These costs consisted of employee separation costs and advisor fees.

Legal Settlement Charges

During the period January 1, 2003 to December 5, 2003, we recorded $462.6 million of legal settlement charges which consisted of the following. We recorded $396.0 million in connection with the resolution of an arbitration claim asserted by FirstEnergy Corp. As a result of this resolution, FirstEnergy retained ownership of the Lake Plant Assets and received an allowed general unsecured claim of $396.0 million under NRG Energy's plan of reorganization. In November 2003, we settled litigation with Fortistar Capital in which Fortistar Capital released us from all litigation claims in exchange for a $60.0 million pre-petition bankruptcy claim and an $8.0 million post-petition bankruptcy claim. We had previously recorded $10.8 million in connection with various legal disputes with Fortistar Capital; accordingly, we recorded an additional $57.2 million during November 2003. In November 2003, we settled our dispute with Dick Corporation in connection with Meriden Gas Turbines LLC through the payment of a general unsecured claim and a post-petition pre-confirmation payment. This settlement resulted in our recording an additional liability of $8.0 million in November 2003.

In August 1995, we entered into a Marketing, Development and Joint Proposing Agreement, or the Marketing Agreement, with Cambrian Energy Development LLC, or Cambrian. Various claims arose in connection with the Marketing Agreement. In November 2003, we entered into a settlement agreement with Cambrian where we agreed to transfer our 100% interest in three gasco projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville) and our 50% interest in two genco projects (MM Phoenix and MM Woodville) to Cambrian. In addition, we paid approximately $1.8 million in settlement of royalties incurred in connection with the Marketing Agreement. We had previously recorded a liability for royalties owed to Cambrian, therefore, we recorded an additional $1.4 million during November 2003.

Fresh Start Adjustments

During the fourth quarter of 2003, we recorded a net credit of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) in connection with fresh start adjustments. Following is a summary of the significant effects of the reorganization and Fresh Start:

	(In millions)
Discharge of corporate level debt	$ 5,162
Discharge of other liabilities	811
Establishment of creditor pool	(1,040)
Receivable from Xcel	640
Revaluation of fixed assets	(1,392)
Revaluation of equity investments	(207)
Valuation of SO_2 emission credits	374
Valuation of out of market contracts, net	(400)
Fair market valuation of debt	108
Valuation of pension liabilities	(61)
Other valuation adjustments	(100)
Total Fresh Start adjustments	3,895
Less discontinued operations	(224)
Total Fresh Start adjustments — continuing operations	$ 4,119

Other Income (Expense)

Reorganized NRG

Other income (expense) for the period December 6, 2003 through December 31, 2003, was an expense of $5.4 million and consisted primarily of $18.9 million of interest expense, partially offset by $13.5 million of equity in earnings of unconsolidated affiliates.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded other expense of $286.9 million. Other expense consisted primarily of $329.9 million of interest expense and $147.1 million of write downs and losses on sales of equity method investments, partially offset by equity in earnings of unconsolidated affiliates of $170.9 million and $19.2 million of other income.

For the year ended December 31, 2002, other expenses were $572.2 million, which consisted primarily of $452.2 million of interest expense and $200.5 million of write downs and losses on sales of equity method investments, partially offset by equity in earnings of unconsolidated affiliates of $69.0 million and other income, net of $11.5 million.

Minority Interest in Earnings of Consolidated Subsidiaries

For the period December 6, 2003 through December 31, 2003, minority interest in earnings of consolidated subsidiaries was $134,000 and relates primarily to Northbrook New York and Northbrook Energy.

Equity in Earnings of Unconsolidated Affiliates

Reorganized NRG

Equity in earnings of unconsolidated affiliates of $13.5 million for the period December 6, 2003 through December 31, 2003 consists primarily of equity earnings from our 50% ownership in West Coast Power of $9.4 million.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded $170.9 million of equity earnings from investments in unconsolidated affiliates. Our 50% investment in West Coast Power comprised $98.7 million of this amount with our investments in the Mibrag, Loy Yang, Gladstone and Rocky Road projects comprising $21.8 million, $17.9 million, $12.4 million and $6.9 million, respectively, with the remaining amounts attributable to various domestic and international equity investments. Our investment in West Coast Power continues to generate favorable earnings as well as our investments in Mibrag, Loy Yang, Gladstone and Rocky Road. For the year ended December 31, 2002, equity earnings from investments in unconsolidated affiliates was $69.0 million.

Write-Downs and Losses on Sales of Equity Method Investments

As we periodically review our equity method investments for impairments, we have taken substantial write-downs and losses on sales of equity method investments during the period January 1, 2003 through December 5, 2003 and for the year 2002. During the period January 1, 2003 to December 5, 2003, we recorded impairments and losses on the sales of investments of $147.1 million compared to $200.5 million in 2002. The $147.1 million recorded in 2003 consists primarily of the write down of our investment in the Loy Yang project of $146.4 million, our investment in the NEO Corporation — Minnesota Methane project of $12.3 million and our investment in NEO Corporation — MM Biogas of $2.6 million. These losses were partially offset by gains on the sale of our investment in the ECKG and Mustang projects of $2.9 million and $12.1 million, respectively. During 2002 we recorded write-downs and losses on sales of equity method investments of $200.5 million. The $200.5 million recorded in 2002 consists primarily of a write down of our investment in the Loy Yang project of $111.4 million, a loss of $48.4 million on the transfer of our interest in the Sabine River Works project to our partner, a $14.2 million write down related to our investment in our EDL project, a write down of our investment in our Kondapalli project of $12.7 million and a write down of our investment in NEO Corporation — Minnesota Methane and MM Biogas of $12.3 million and $3.2 million, respectively among others, offset by a $9.9 million gain on sale of our Kingston project.

Other income, net

Other income, net consists primarily of interest income earned on notes receivable and cash balances. We recorded $97,000, $19.2 million and $11.4 million of other income, net for the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003 and for the year ended December 31, 2002, respectively.

Interest expense

Reorganized NRG

Interest expense for the period December 6, 2003 through December 31, 2003 of $18.9 million consists primarily of interest expense at the corporate level, primarily related to the Second Priority Notes, term loan facility and revolving line of credit used to refinance certain project-level financings. In addition, interest expense includes the amortization of deferred financing costs incurred as a result of our refinancing efforts and the amortization of discounts and premiums recorded upon the marking of our debt to fair value upon our adoption of the Fresh Start provision of SOP 90-7.

Predecessor Company

Interest expense for the period January 1, 2003 through December 5, 2003 of $329.9 million consisted of interest expense on both our project and corporate level interest bearing debt. In addition, interest expense includes the amortization of debt issuance costs and any interest rate swap termination costs. Subsequent to our entering into bankruptcy we ceased the recording of interest expense on our corporate level debt as these pre-petition claims were deemed to be impaired and subject to compromise. We did not however cease to record interest expense on the project-level debt outstanding at our Northeast Generating and South Central Generating facilities even though these entities were also in bankruptcy as these claims were deemed to be most likely not impaired and not subject to compromise. We also recorded substantial amounts of fees and costs related to our acquiring a debtor in possession financing arrangement while we were in bankruptcy. In addition, upon our emergence from bankruptcy we wrote off any remaining deferred finance costs related to our corporate and project-level debt including our Northeast and South Central project-level debt as it was probable that they would be refinanced upon our emergence from bankruptcy.

Interest expense was $452.2 million for the year ended December 31, 2002.

Income Tax

Reorganized NRG

Income tax benefit for the period December 6, 2003 through December 31, 2003 was ($0.7) million and the overall effective tax rate was (6.2%). The rate is lower than the U.S. statutory rate primarily due to a state tax refund received from Xcel Energy in 2003, foreign income taxed in jurisdictions with tax rates different from the U.S. statutory rate and a decrease in unfavorable permanent differences.

Our deferred tax assets at December 31, 2003 were offset by a full valuation allowance in accordance with SFAS No. 109. Under SOP 90-7, any future benefits from reducing a valuation allowance from preconfirmation deferred tax assets are required to be reported as a direct addition to paid in capital versus a benefit on our income statement. Consequently, our effective tax rate in post-bankruptcy emergence years will not benefit from the realization of our deferred tax assets, which were fully valued as of the date of our emergence from bankruptcy. The adoption of this Statement of Position will result in a disallowance of a future income statement benefit of $1.3 billion as a result of a reduction to the intangible asset for realization of benefits of fully valued deferred tax assets as of December 5, 2003 (date of emergence from bankruptcy).

The effective tax rate may vary from year to year depending on, among other factors, the geographic and business mix of earnings and losses. These same and other factors, including history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Predecessor Company

Income tax expense (benefit) for the period January 1, 2003 through December 5, 2003 was a tax expense of $37.9 million and a tax benefit of ($166.9) million for the year ended December 31, 2002. The overall effective tax rate for the short period ended December 5, 2003 and the year ended December 31, 2002 was 1.3% and 5.6%, respectively. The change in our effective tax rate was primarily due to a release in valuation allowance for net operating loss carryforwards that were utilized following our emergence from bankruptcy to offset the current tax on cancellation of debt income.

Discontinued Operations

Reorganized NRG

Discontinued operations for the period December 6, 2003 through December 31, 2003 is comprised of a loss of $0.4 million attributable to the on going operations of our McClain, PERC, Cobee, LSP Energy, Hsin Yu and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC).

Predecessor Company

As of December 5, 2003, we classified as discontinued operations the operations and gains/losses recognized on the sales of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. For the period January 1, 2003 through December 5, 2003, discontinued operations consist of the historical operations and net gains/losses related to our Killingholme, McClain, PERC, Cobee, NLGI, seven NEO Corporation projects, TERI, Cahua, Energia Pacasmayo, LSP Energy and Hsin Yu projects. Discontinued operations for the year ended December 31, 2002 consisted of our Crockett Cogeneration, Entrade, Killingholme, Csepel, Bulo Bulo, McClain, PERC, Cobee, NLGI, seven NEO Corporation projects, TERI, Cahua, Energia Pacasmayo, LSP Energy and Hsin Yu projects.

For the period January 1, 2003 through December 5, 2003, the results of operations related to such discontinued operations was a net loss of $182.6 million due to a loss on the sale of our Peru projects, impairment charges of $100.7 million and $23.6 million, respectively, recorded at McClain and NLGI and fresh start adjustments at LSP Energy.

During 2002, we recognized a loss on discontinued operations of $675.8 million due primarily to asset impairments recorded at Killingholme, NLGI, TERI, LSP Energy and Hsin Yu projects.

Reorganization and Emergence from Bankruptcy

On May 14, 2003, we and 25 of our U.S. affiliates, filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code, or the Bankruptcy Code, in the United States Bankruptcy Court for the Southern District of New York, or the bankruptcy court.

On May 15, 2003, NRG Energy, PMI, NRG Finance Company I LLC, NRGenerating Holdings (No. 23) B.V. and NRG Capital LLC, collectively the Plan Debtors, filed the NRG plan of reorganization and the related Disclosure Statement for Reorganizing Debtors' Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code, as subsequently amended, or the Disclosure Statement. The Bankruptcy Court held a hearing on the Disclosure Statement on June 30, 2003, and instructed the Plan Debtors to include certain additional disclosures. The Plan Debtors amended the Disclosure Statement and obtained Bankruptcy Court approval for the Third Amended Disclosure Statement for Debtors' Second Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code.

On November 24, 2003, the bankruptcy court issued an order confirming the NRG plan of reorganization, and the plan became effective on December 5, 2003. On September 17, 2003, the Northeast/South Central plan of reorganization was proposed after we secured the necessary financing commitments. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/South Central plan of reorganization and the plan became effective on December 23, 2003.

Financial Reporting by Entities in Reorganization under the Bankruptcy Code and Fresh Start

Between May 14, 2003 and December 5, 2003, we operated as a debtor-in-possession under the supervision of the bankruptcy court. Our financial statements for reporting periods within that timeframe were prepared in accordance with the provisions of Statement of Position 90-7, *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code"*, or SOP 90-7.

For financial reporting purposes, the close of business on December 5, 2003, represents the date of emergence from bankruptcy. As used herein, the following terms refer to the Company and its operations:

"Predecessor Company"	The Company, pre-emergence from bankruptcy The Company's operations prior to December 6, 2003
"Reorganized NRG"	The Company, post-emergence from bankruptcy The Company's operations from December 6, 2003-December 31, 2004

The implementation of the NRG plan of reorganization resulted in, among other things, a new capital structure, the satisfaction or disposition of various types of claims against the Predecessor Company, the assumption or rejection of certain contracts, and the establishment of a new board of directors.

In connection with the emergence from bankruptcy, we adopted Fresh Start in accordance with the requirements of SOP 90-7. The application of SOP 90-7 resulted in the creation of a new reporting entity. Under Fresh Start, the enterprise value of our company was allocated among our assets and liabilities on a basis substantially consistent with purchase accounting in accordance with SFAS No. 141 *"Business Combinations"*, or SFAS No. 141. Accordingly, we pushed down the effects of this allocation to all of our subsidiaries.

Under the requirements of Fresh Start, we have adjusted our assets and liabilities, other than deferred income taxes, to their estimated fair values as of December 5, 2003. As a result of marking our assets and liabilities to their estimated fair values, we determined that there was no excess reorganization value that was reallocated back to our tangible and intangible assets. Deferred taxes were determined in accordance with SFAS No. 109, *"Accounting for Income Taxes."* The net effect of all Fresh Start adjustments resulted in a gain of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations), which is reflected in the Predecessor Company's results of operations for the period January 1, 2003 through December 5, 2003. The application of the Fresh Start provisions of SOP 90-7 created a new reporting entity having no retained earnings or accumulated deficit.

As part of the bankruptcy process we engaged an independent financial advisor to assist in the determination of our reorganized enterprise value. The fair value calculation was based on management's forecast of expected cash flows from our core assets. Management's forecast incorporated forward commodity market prices obtained from a third party consulting firm. A discounted cash flow calculation was used to develop the enterprise value of Reorganized NRG, determined in part by calculating the weighted average cost of capital of the Reorganized NRG. The Discounted Cash Flow, or DCF, valuation methodology equates the value of an asset or business to the present value of expected future economic benefits to be generated by that asset or business. The DCF methodology is a "forward looking" approach that discounts expected future economic benefits by a theoretical or observed discount rate. The independent financial advisors prepared a 30-year cash flow forecast using a discount rate of approximately 11%. The resulting reorganization enterprise value as included in the Disclosure Statement ranged from $5.5 billion to $5.7 billion. The independent financial advisor then subtracted our project-level debt and made several other adjustments to reflect the values of assets held for sale, excess cash and collateral requirements to estimate a range of Reorganized NRG equity value of between $2.2 billion and $2.6 billion.

In constructing our Fresh Start balance sheet upon our emergence from bankruptcy, we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Our NRG plan of reorganization provided for the issuance of 100,000,000 shares of NRG common stock to the various creditors resulting in a calculated price per share of $24.04. Our reorganization value of approximately $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. The reorganization value represents the fair value of an entity before liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after restructuring. This value is consistent with the voting creditors and bankruptcy court's approval of the NRG plan of reorganization.

We recorded approximately $3.9 billion of net reorganization income (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) in the Predecessor Company's statement of operations for 2003, which includes the gain on the restructuring of equity and the discharge of obligations subject to compromise for less than recorded amounts, as well as adjustments to the historical carrying values of our assets and liabilities to fair market value.

Due to the adoption of Fresh Start as of December 5, 2003, the Reorganized NRG post-Fresh Start statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are therefore not comparable in certain respects to the financial statements prior to the application of Fresh Start. The accompanying Consolidated Financial Statements have been prepared to distinguish between Reorganized NRG and the Predecessor Company.

APB No. 18, *"The Equity Method of Accounting for Investments in Common Stock,"* requires us to effectively push down the effects of Fresh Start reporting to our unconsolidated equity method investments and to recognize an adjustment to our share of the earnings or losses of an investee as if the investee were a consolidated subsidiary. As a result of pushing down the impact of Fresh Start to our West Coast Power affiliate, we determined that a contract based intangible asset with a one year remaining life, consisting of the value of West Coast Power's California Department of Water Resources energy sales contract, must be established and recognized as a basis adjustment to our share of the future earnings generated by West Coast Power. This adjustment reduced our equity earnings in the amount of $115.8 million for the year ended December 31, 2004. This contract expired in December 2004.

Liquidity and Capital Resources

Reorganized Capital Structure

In connection with the consummation of our reorganization, on December 5, 2003, all shares of our old common stock were canceled and 100,000,000 shares of new common stock of NRG Energy were distributed pursuant to such plan in accordance with Section 1145 of the bankruptcy code to the holders of certain classes of claims. We received no proceeds from such issuance. A certain number of shares of common stock were issued and placed in the Disputed Claims Reserve for distribution to holders of disputed claims as such claims are resolved or settled. See Item 3 — Legal Proceedings — Disputed Claims Reserve. In the event our disputed claims reserve is inadequate, it is possible we will have to issue additional shares of our common stock to satisfy such pre-petition claims or contribute additional cash proceeds. Our authorized capital stock consists of 500,000,000 shares of NRG Energy common stock and 10,000,000 shares of preferred stock. A total of 4,000,000 shares of our common stock are available for issuance under our long-term incentive plan.

In addition to our issuance of new common stock, on December 23, 2003, we completed a note offering consisting of $1.25 billion of 8% Second Priority Senior Secured Notes due 2013, or the Second Priority Notes, and we entered into a new $1.45 billion credit facility consisting of a $950.0 million term loan facility, a $250.0 million funded letter of credit facility and a $250.0 million revolving credit facility. In connection with the consummation of the NRG plan of reorganization, we issued to Xcel Energy a $10.0 million non-amortizing promissory note, which accrues interest at a rate of 3% per annum and matures 2.5 years after the effective date of the NRG plan of reorganization. In January 2004, we completed a supplementary note offering whereby we issued an additional $475.0 million of the Second Priority Notes at a premium and used the proceeds to repay a portion of the $950.0 million term loan. On December 24, 2004, we amended and restated our existing $1.45 billion credit facility, recasting it as a $950 million secured credit facility made up of a $450.0 million seven-year senior secured term loan, a $350.0 million funded letter of credit facility and a three-year $150.0 million revolving line of credit. In December 2004, we also issued $420 million of convertible preferred stock and used the proceeds from such issuance to redeem $375 million of the Second Priority Notes in February 2005. Also in January 2005 and in March 2005, we used existing cash to purchase, at market prices, $25 million and $15.8 million, respectively, in face value of our Second Priority Notes. These notes were assumed by NRG Energy and therefore remain outstanding. As of March 21, 2005, we had $1.35 billion in aggregate principal amount of Second Priority Notes outstanding, $450.0 million principal amount outstanding under the term loan and $350 million of the funded letter of credit facility outstanding. $178.3 million of undrawn letters of credit remain available under the funded letter of credit facility. As of March 21, 2005, we had not drawn down on our revolving credit facility.

The following table summarizes the debt transactions:

	Date of Transaction	Original Amount	Outstanding at December 31, 2003	Activity	Outstanding at December 31, 2004	Activity	Outstanding at March 21, 2005
				(In thousands)			
Xcel Promissory Note	Dec. 6, 2003	$ 10,000	$ 10,000		$ 10,000		$ 10,000
NRG 8% Senior Secured Notes	Dec. 23, 2003	$1,250,000	$1,250,000		$1,250,000		
Tack-on offering	Jan. 28, 2004			$475,000	$ 475,000		
					$1,725,000		$1,725,000
Repurchase of Notes*	Jan. 21-27, 2005					$ (25,000)	
Early Redemption	Feb. 4, 2005					$(375,000)	(375,000)
Repurchase of Notes*	March 28, 2005					$ (15,838)	
							$1,350,000
NRG Credit Facility Term loan	Dec. 23, 2003	$ 950,000	$ 950,000				
Letter of Credit facility	Dec. 23, 2003	250,000	$ 250,000				
Corporate Revolver	Dec. 23, 2003	250,000	—				
NRG New Credit Facility		$1,450,000	$1,200,000				
Refinancing of the Credit Facility							
Amended Credit Facility							
Term loan	Dec. 24, 2004	$ 450,000			$ 450,000		$ 450,000
Letter of Credit facility	Dec. 24, 2004	350,000			350,000		350,000
Corporate Revolver	Dec. 24, 2004	150,000			—		—
NRG Amended Credit Facility		$ 950,000			$ 800,000		$ 800,000
Total Corporate Level Debt			$2,460,000		$2,535,000		$2,160,000

* The notes were assumed by NRG Energy and remain outstanding.

As part of the NRG plan of reorganization, we eliminated approximately $5.2 billion of corporate level bank and bond debt and approximately $1.3 billion of additional claims and disputes through our distribution of new common stock and $1.04 billion in cash among our unsecured creditors. In addition to the debt reduction associated with the restructuring, we used the proceeds of the Second Priority Notes and borrowings under our credit facility to retire approximately $1.7 billion of project-level debt.

For additional information on our short-term and long-term borrowing arrangements, see Item 15 — Note 18 to the Consolidated Financial Statements.

Historical Cash Flows

Reorganized NRG

We have obtained cash from operations, Xcel Energy's contribution net of distributions to creditors, proceeds from the sale of certain assets, borrowings under our Second Priority Notes and credit facilities and the proceeds from the sale of preferred stock. We have used these funds to finance operations, service debt obligations, finance capital expenditures, repurchase common stock and meet other cash and liquidity needs.

Predecessor Company

Historically, we have obtained cash from operations, issuance of debt and equity securities, borrowings under credit facilities, capital contributions from Xcel Energy, reimbursement by Xcel Energy of tax benefits pursuant to a tax sharing agreement and proceeds from non-recourse project financings. We used these funds to finance operations, service debt obligations, fund the acquisition, development and construction of generation facilities, finance capital expenditures and meet other cash and liquidity needs.

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	For the Period December 6-December 31, 2003	For the Period January 1-December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
Net cash provided (used) by operating activities	$ 643,993	$(588,875)	$ 238,509	$ 430,042
Net cash (used) provided by investing activities	184,685	363,372	(185,679)	(1,681,467)
Net cash provided (used) by financing activities	(283,734)	393,273	(29,944)	1,449,330

Net Cash Provided (Used) By Operating Activities

Reorganized NRG

For the year ended December 31, 2004, net cash provided by operating activities was $644.0 million. Net income of $185.6 million and adjustments of $383.3 million accounted for $568.9 million of the total cash provided by operating activities. Non-cash adjustments consist primarily of depreciation, amortization and impairment charges offset by unrealized gains on derivatives. Cash provided by working capital of $75.0 million reflects a $100 million net resolution of a bankruptcy-related receivable and payable offset by other working capital changes of $25.0 million.

For the period December 6, 2003 through December 31, 2003, net cash used by operating activities was $588.9 million. This was primarily a result of payments made to creditors upon our emergence from bankruptcy.

Predecessor Company

For the period January 1, 2003 through December 5, 2003, net cash provided by operating activities was $238.5 million. Operating activities consisted of a net loss before Fresh Start adjustments of $1.1 billion, offset by non-cash charges of $567.5 million and cash provided by working capital of $800.1 million. The non-cash charges consisted primarily of the write-down of our investment in Loy Yang, asset impairments and legal settlement charges. The favorable change in working capital was primarily due to reduced cash expenditures throughout the bankruptcy period resulting in increased accounts payable.

For the year ended December 31, 2002, net cash provided by operating activities was $430.0 million. Operating activities consisted of a net loss before restructuring and impairment charges of $319.8 million offset by non-cash charges of $144.5 million and cash provided by working capital of $605.3 million.

Net Cash Provided (Used) By Investing Activities

Reorganized NRG

For the year ended December 31, 2004, net cash provided by investing activities was $184.7 million due primarily to sales proceeds, net of cash on hand, of $252.7 million on the sale of discontinued operations and sale proceeds of $50.7 million from the sale of investments, offset by capital expenditures of $114.4 million.

For the period December 6, 2003 through December 31, 2003, net cash provided by investing activities was $363.4 million. In connection with the refinancing transaction, approximately $375.3 million of restricted cash was released upon payment of the Northeast Generating and South Central Generating note. This increase was offset by funds used for capital expenditures and investments in projects.

Predecessor Company

For the period January 1, 2003 through December 5, 2003, net cash used in investing activities was $185.7 million. This was primarily a result of capital expenditures and an increase in restricted cash, offset by cash proceeds received upon the sale of investments.

For the year ended December 31, 2002, net cash used by investing activities was $1.7 billion due primarily to $1.4 billion of capital expenditures.

Net Cash Provided (Used) By Financing Activities

Reorganized NRG

For the year ended December 31, 2004, net cash used by financing activities was $283.7 million primarily due to reduction of long-term debt by $159.3 million, which was primarily related to the McClain sale. Financing activities were also driven by an increase in the funded letter of credit asset balance of $100.0 million. In December 2004, the Company issued preferred stock for net proceeds of $406.4 million which enabled us to redeem $375.0 million of senior secured notes in 2005. Available cash balances were used to purchase 13 million shares of common stock owned by MatlinPatterson for a price of $405.3 million.

For the period December 6, 2003 through December 31, 2003, net cash provided by financing activities was $393.3 million. We entered into refinancing transactions on December 23, 2003, where we issued $1.25 billion of Second Priority Notes and entered into the New Credit Facility, which consisted of a $950.0 million senior secured term loan facility, a $250.0 million funded letter of credit facility and a $250.0 million unfunded revolving line of credit. Upon completion of the refinancing transactions, we repaid the Northeast Generating and South Central Generating notes and the Mid-Atlantic Generating obligations.

Predecessor Company

For the period January 1, 2003 through December 5, 2003, net cash used by financing activities was $29.9 million, which consisted primarily of principal payments offset by the issuance of additional debt.

For the year ended December 31, 2002, net cash provided by financing activities was $1.4 billion which consisted primarily of increased debt of $945.3 and a capital contribution from Xcel Energy in the amount of $500.0 million.

Sources of Funds

The principal sources of liquidity for our future operations and capital expenditures are expected to be: (i) existing cash on hand and cash flows from operations and (ii) proceeds from the sale of certain assets and businesses. Additionally, we have approximately $192.9 million of undrawn letter of credit capacity under our senior credit facility as of December 31, 2004.

On December 24, 2004, we amended our corporate bank facility, which at December 31, 2004 consists of a $450.0 million, seven-year senior secured term loan, a $350.0 million funded letter of credit facility, and a three-year $150.0 million revolving line of credit, or the revolving credit facility. With the refinancing, we lowered the interest rate on the term loan to LIBOR plus 1.875% from LIBOR plus 4.0%. Portions of the revolving credit facility are available as a swing-line facility and as a revolving letter of credit sub-facility. As of December 31, 2004, the corporate revolver was undrawn.

On December 27, 2004, we completed the sale of $420 million of convertible perpetual preferred stock with a dividend coupon rate of 4%. The Preferred Stock has a liquidation preference of $1,000 per share of Preferred Stock. Holders of Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors, out of funds legally available therefore, cash dividends at the rate of 4% per annum, payable quarterly in arrears on March 15, June 15, September 15 and December 15 of each year, commencing on March 15, 2005. The Preferred Stock is convertible, at the option of the holder, at any time into shares of our common stock at an initial conversion price of $40.00 per share, which is equal to an approximate conversion rate of 25 shares of common stock per share of Preferred Stock, subject to specified adjustments. On or after

December 20, 2009, we may redeem, subject to certain limitations, some or all of the Preferred Stock with cash at a redemption price equal to 100% of the liquidation preference, plus accumulated but unpaid dividends, including liquidated damages, if any, to the redemption date.

Proceeds of $406.4 million from the sale of the preferred securities are net of securities issuance costs of approximately $13.6 million, and on February 4, 2005, these proceeds along with cash on hand were used to redeem $375.0 million in Second Priority Notes, pay an early redemption penalty of $30.0 million and pay accrued interest of $4.1 million on the redeemed notes.

Cash Flows. Our operating cash flows are expected to be impacted by, among other things: (i) spark spreads generally; (ii) commodity prices (including demand for natural gas, coal, oil and electricity); (iii) the cost of ordinary course operations and maintenance expenses including margin and collateral calls for our trading operation; (iv) planned and unplanned outages; (v) contraction of terms by trade creditors; (vi) cash requirements for closure and restructuring of certain facilities; (vii) restrictions in the declaration or payments of dividends or similar distributions from our subsidiaries; and (viii) the timing and nature of asset sales.

A principal component of the NRG plan of reorganization is a settlement with Xcel Energy in which Xcel Energy agreed to make a contribution to us consisting of cash (and, under certain circumstances, its common stock) in an aggregate amount of up to $640.0 million to be paid in three separate installments. Xcel Energy contributed $288.0 million on February 20, 2004, $328.5 million on April 30, 2004 and $23.5 million on May 28, 2004. We distributed $540.0 million of cash we received from Xcel Energy to our creditors pursuant to our plan of reorganization. We retained the remaining $100.0 million, which we used for general corporate purposes.

Asset Sales. We received $303.4 million, $196.5 million and $229.3 million in cash proceeds from the sale of certain assets and businesses in the fiscal years ended 2004, 2003 and 2002, respectively. The Amended Credit Facility and the indenture governing the notes place restrictions on the use of any proceeds we may receive from certain asset sales in the future.

Letter of Credit Sub-facility and Revolving Credit Facility. The Amended Credit Facility includes a letter of credit sub-facility in the amount of $350.0 million. As of December 31, 2004, we had issued $157.1 million in letters of credit under this facility, leaving $192.9 million available for future issuance. The Amended Credit Facility also includes a revolving credit facility in the amount of $150.0 million to be used for general corporate purposes. On December 31, 2004 our revolving credit facility was undrawn. For additional information regarding our debt see Item 15 — Note 18 to the Consolidated Financial Statements.

Uses of Funds

Our requirements for liquidity and capital resources, other than for operating our facilities, can generally be categorized by the following: (i) PMI activities; (ii) capital expenditures; (iii) corporate financial restructuring and (iv) project finance requirements for cash collateral.

PMI. PMI activities comprise the single largest requirement for liquidity and capital resources. PMI liquidity requirements are primarily driven by: (i) margin and collateral posted with counter-parties; (ii) initial collateral required to establish trading relationships; (iii) timing of disbursements and receipts (i.e., buying fuel before receiving energy revenues); and (iv) initial collateral for large structured transactions. As of December 31, 2004, PMI had total collateral outstanding of $47.8 million in margin, prepayments and cash deposits and $83.1 million outstanding in letters of credit to third parties.

Future liquidity requirements may change based on our hedging activity, fuel purchases, future market conditions, including forward prices for energy and fuel and market volatility. In addition, liquidity requirements are dependent on our credit ratings and general perception of creditworthiness. We do not assume that we will be given unsecured credit from third parties in budgeting our working capital requirements.

Capital Expenditures. Capital expenditures were $114.4 million for the year ended December 31, 2004, $10.6 million for the period December 6, 2003 through December 31, 2003, $113.5 million for the period

January 1, 2003 through December 5, 2003 and $1.4 billion for the year ended 2002. Capital expenditures in 2004 relate primarily to the conversion of our western New York plants to low-sulfur coal, the Playford 2 refurbishment at our Flinders operation in Australia and planned outages across our fleet. Capital expenditures in 2003 relate primarily to operations and maintenance of our existing generating facilities whereas capital expenditures in 2002 related primarily to new plant construction. In 2005, we anticipate we will spend approximately $133.3 million in capital expenditures and an additional $109.5 million in major maintenance expense related primarily to the operation and maintenance of our existing generating facilities.

Corporate Financial Restructuring. We may elect periodically to modify our corporate financial structure in order to increase near-term or long-term cash flows or to reduce exposure to financial risks. On December 21, 2004, we purchased 13 million shares of common equity interest in NRG Energy from investment partnerships managed by MatlinPatterson. Total costs associated with the repurchase, including fees and expenses, was $405.3 million. On February 4, 2005, we used proceeds from our Preferred Stock issuance to redeem early $375.0 million of our Second Priority Notes at par value plus 8%. We also paid outstanding accrued interest and liquidated damage penalties attributable to the redeemed notes. In January 2005 and March 2005, we repurchased $25.0 million and $15.8 million, respectively, of our notes, which remain outstanding. As of March 21, 2005, $1.35 billion in Second Priority Notes remain outstanding.

Preferred Dividend Payment. On March 15, 2005, we made a $3.9 million dividend payment to our preferred shareholders of record as of March 1, 2005. This represents the first quarterly dividend payment we anticipate making to our preferred shareholders.

Project Finance Requirements. We are a holding company and conduct our operations through subsidiaries. Historically, we have utilized project-level debt to fund a significant portion of the capital expenditures and investments required to construct our power plants and related assets. Consistent with our strategy, we may seek, where available on commercially reasonable terms, project-level debt in connection with the assets or businesses that our affiliates or we may develop, construct or acquire. Project-level borrowings are substantially non-recourse to other subsidiaries, affiliates and us, and are generally secured by the capital stock, physical assets, contracts and cash flow of the related project subsidiary or affiliate being financed. Some of these project financings may require us to post collateral in the form of cash or an acceptable letter of credit.

In February 2005, Flinders amended its debt facility of AUD 279.4 million (approximately US $218.5 million) in floating-rate debt. The amendment extended the maturity to February 2017, reduced borrowing costs and reserve requirements, minimized debt service coverage ratios, removed mandatory cash sharing arrangements, and made other minor modifications to terms and conditions. The facility includes an AUD 20 million (approximately US $15.7 million) working capital and performance bond facility. NRG Flinders is required to maintain interest-rate hedging contracts on a rolling 5-year basis at a minimum level of 60% of principal outstanding. Upon execution of the amendment, a voluntary principal prepayment of AUD 50 million (approximately US $39.1 million) was made, reducing the principal balance to AUD 229.2 million (approximately $179.4 million).

Principal on short-term debt, long-term debt and capital leases as of December 31, 2004 are due and payable in the following periods (in thousands):

Subsidiary/Description	Total	2005	2006	2007	2008	2009	Thereafter
Xcel Energy Note	$ 10,000	$ —	$ 10,000	$ —	$ —	$ —	$ —
Credit Facility Due Dec. 2011	800,000	8,000	8,000	8,000	8,000	8,000	760,000
8% Second Priority Notes due Dec. 2013	1,725,000	400,000	—	—	—	—	1,325,000
NRG Energy Center Minneapolis, due 2013 and 2017	118,950	7,877	8,465	9,097	9,776	10,507	73,228
NRG Peaker Finance Co LLC	300,876	4,312	6,768	11,164	12,903	14,758	250,971
Flinders Power Finance Pty	202,856	11,564	13,443	14,633	15,931	14,083	133,202
NRG Energy Center San Francisco	129	32	31	37	29	—	—
Camas Pwr BLR LP Bank facility	6,275	2,442	2,533	1,300	—	—	—
Camas Pwr BLR LP Bonds	4,475	1,385	1,485	1,605	—	—	—
Itiquira Energetica S.A., due January 2012	20,078	2,845	2,845	2,845	2,845	2,845	5,853
Itiquira Energetica S.A., due April 2011	31,002	—	3,875	3,875	3,875	3,875	15,502
Northbrook New York	16,900	500	600	700	800	850	13,450
Northbrook Carolina	2,375	100	100	150	150	150	1,725
Northbrook STS HydroPower	24,329	477	523	572	627	807	21,323
Subtotal Debt, Bonds and Notes	3,263,245	439,534	58,668	53,978	54,936	55,875	2,600,254
Saale Energie GmbH, Schkopau (capital lease)	303,803	69,904	51,785	38,612	31,693	23,786	88,023
Audrain Generating (capital lease)	239,930	—	—	—	—	—	239,930
Conemaugh Fuels LLC (capital lease)	218	16	18	19	20	22	123
Subtotal Capital Leases	543,951	69,920	51,803	38,631	31,713	23,808	328,076
Total Debt	$3,807,196	$509,454	$110,471	$92,609	$86,649	$79,683	$2,928,330

These amounts reflect scheduled amortization of principal as of December 31, 2004, with the exception of the 8% Senior Secured Notes, for which 2005 amounts reflect early redemption and repurchases made through March 21, 2005. See Item 15 — Note 18 to the Consolidated Financial Statements for further discussion on events that may affect debt payment schedules.

On December 24, 2004, we amended and restated our senior credit facility, which now consists of a $450.0 million, seven-year senior secured term loan facility, a $350.0 million funded letter of credit facility, and a three-year revolving credit facility in an amount up to $150.0 million. At that time, we paid $13.8 million in prepayment breakage costs, $3.2 million in accrued but unpaid interest and fees, and $16.7 million in other costs associated with the amendment. The balance outstanding under this facility was $800.0 million as of December 31, 2004. Other expenses include commitment fees on the undrawn portion of the revolving credit facility, participation fees for the credit-linked deposit and other fees.

As of December 31, 2004, the $350.0 million letter of credit facility was fully funded and reflected as a funded letter of credit on the December 31, 2004 balance sheet. As of December 31, 2004, $157.1 million in letters of credit had been issued under this facility, leaving $192.9 million available for future issuances.

If we decide not to provide any additional funding or credit support to our subsidiaries, the inability of any of our subsidiaries that have near-term debt payment obligations to obtain non-recourse project financing may result in such subsidiary's insolvency and the loss of our investment in such subsidiary. Additionally, the loss of a significant customer at any of our subsidiaries could result in the need to restructure the non-recourse project financing at that subsidiary, and the inability to successfully complete a restructuring of the non-recourse project financing may result in a loss of our investment in such subsidiary. Certain of our projects are subject to restrictions regarding the movement of cash. For additional information see Item 15 — Note 18 to the Consolidated Financial Statements.

Liquidity Estimates

For 2005, we anticipate utilizing $300 million of our letter of credit facility. In addition, PMI may require additional capital resources depending upon our hedging activity, fuel purchases and future market conditions. As part of our refinancing transactions, we have a $150.0 million revolving credit facility. The revolving credit facility was established to satisfy short-term working capital requirements, which may arise from time to time. It is not our current intention to draw funds under the revolving credit facility.

On February 4, 2005, utilizing net proceeds of $406.4 million from the sale of preferred securities in December 2004, we redeemed $375.0 million in Second Priority Notes. At the same time, we paid $30.0 million for the early redemption premium on the redeemed notes, $4.1 million in accrued but unpaid interest on the redeemed notes and $0.4 million in accrued but unpaid liquidated damages on the redeemed notes.

On March 15, 2005, we made a $3.9 million dividend payment to our preferred shareholders of record as of March 1, 2005. This represents the first quarterly dividend payment we anticipate making to our preferred shareholders.

Other Liquidity Matters

We expect our capital requirements to be met with existing cash balances, cash flows from operations, borrowings under our Second Priority Notes and Amended Credit Facility, and asset sales. We believe that our current level of cash availability and asset sales, along with our future anticipated cash flows from operations, will be sufficient to meet the existing operational and collateral needs of our business for the next 12 months. Subject to restrictions in our Second Priority Notes and our Amended Credit Facility, if cash generated from operations is insufficient to satisfy our liquidity requirements, we may seek to sell assets, obtain additional credit facilities or other financings and/or issue additional equity or convertible instruments. We cannot assure you, however, that our business will generate sufficient cash flow from operations, such that currently anticipated cost savings and operating improvements will be realized on schedule or that future borrowings will be available to us under our credit facilities in an amount sufficient to enable us to pay our indebtedness, or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness, on or before maturity. We cannot assure you that we will be able to refinance any of our indebtedness, on commercially reasonable terms or at all. To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control.

Net Operating Loss Carryforwards

For the year ended December 31, 2004, we generated a net operating loss carryforward of $102.1 million which will expire through 2024. We believe that it is more likely than not that no benefit will be realized on the deferred tax assets relating to the net operating loss carryforwards. This assessment included consideration of positive and negative factors, including our current financial position and results of operations, projected future taxable income, including projected operating and capital gains, and available tax planning strategies. Therefore, as of December 31, 2004, a valuation allowance of $707.9 million was recorded against the net deferred tax assets, including net operating loss carryforwards in accordance with SFAS No. 109.

Off-Balance Sheet Items

As of December 31, 2004, we have not entered into any financing structure that is designed to be off-balance sheet that would create liquidity, financing or incremental market risk or credit risk to us. However, we have numerous investments with an ownership interest percentage of 50% or less in energy and energy related entities that are accounted for under the equity method of accounting as disclosed in Item 15 —

Note 13 to the Consolidated Financial Statements. Our pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $251.7 million as of December 31, 2004. The decline was largely a result of sales of our interest in Calpine Cogeneration, Loy Yang and Commonwealth Atlantic. In the normal course of business we may be asked to loan funds to the unconsolidated affiliates on both a long and short-term basis. Such transactions are generally accounted for as accounts payable and receivable to/from affiliates and notes payable/receivable to/from affiliates and if appropriate, bear market-based interest rates. See Item 15 — Note 11 to the Consolidated Financial Statements for additional information regarding amounts accounted for as notes receivable — affiliates.

Contractual Obligations and Commercial Commitments

We have a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to our capital expenditure programs. The following is a summarized table of contractual obligations. See additional discussion in Item 15 — Notes 18, 27 and 29 to the Consolidated Financial Statements.

	Payments Due by Period as of December 31, 2004				
Contractual Cash Obligations	Total	Short-term	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Long-term debt	$4,783,626	$614,573	$461,833	$460,372	$3,246,848
Capital lease obligations (including estimated interest)	1,263,658	115,558	177,436	136,940	833,724
Operating leases	140,324	16,176	32,383	28,822	62,943
Coal purchase and transportation obligations	351,182	118,679	135,176	75,628	21,699
Total contractual cash obligations	$6,538,790	$864,986	$806,828	$701,762	$4,165,214

	Amount of Commitment Expiration per Period as of December 31, 2004				
Other Commercial Commitments	Total Amounts Committed	Short-term	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Funded standby letters of credit	$157,144	$157,144	$ —	$ —	$ —
Unfunded standby letters of credit	16,103	16,103	—	—	—
Surety bonds	4,467	4,467	—	—	—
Asset sales guarantee obligations	73,515	1,000	250	12,500	59,765
Commodity sales guarantee obligations	57,600	24,100	—	—	33,500
Other guarantees	94,126	—	778	—	93,348
Total commercial commitments	$402,955	$202,814	$1,028	$12,500	$186,613

In December 2004, we entered into a long-term coal transport agreement with the Burlington Northern and Santa Fe Railway Company and affiliates of American Commercial Lines LLC to deliver low sulfur coal to our Big Cajun II facility in New Roads, Louisiana beginning April 1, 2005. In December 2004, we also entered into coal purchase contracts extending through 2007. In March 2005, we entered into an agreement to purchase 23.75 million tons of coal over a period of four years and nine months from Buckskin Mining Company or Buckskin. The coal will be sourced from Buckskin's mine in the Powder River Basin, Wyoming, and will be used primarily in NRG Energy's coal-burning generation plants in the South Central region.

In August 2004, we entered into a contract to purchase 1,540 aluminum railcars from Johnston America Corporation to be used for the transportation of low sulfur coal from Wyoming to NRG Energy's coal burning generating plants, including the Cajun Facilities. On February 18, 2005, we entered into a ten-year operating lease agreement with GE Railcar Services Corporation, or GE, for the lease of 1,500 railcars and delivery commenced in February 2005. We have assigned certain of our rights and obligations for 1,500 railcars under the purchase agreement with Johnston America to GE. Accordingly, the railcars which we lease from GE under the arrangement described above will be purchased by GE from Johnston America in lieu of our purchase of those railcars.

Interdependent Relationships

We do not have any significant interdependent relationships.

Derivative Instruments

We may enter into long-term power sales contracts, long-term gas purchase contracts and other energy related commodities financial instruments to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect fuel inventories. In addition, in order to mitigate interest rate risk associated with the issuance of our variable rate and fixed rate debt, we enter into interest rate swap agreements.

The tables below disclose the trading activities that include non-exchange traded contracts accounted for at fair value. Specifically, these tables disaggregate realized and unrealized changes in fair value; identify changes in fair value attributable to changes in valuation techniques; disaggregate estimated fair values at December 31, 2004 based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at December 31, 2004.

Derivative Activity Gains/(Losses)

	Reorganized NRG
	(In thousands)
Fair value of contracts at December 31, 2003	$(93,253)
Contracts realized or otherwise settled during the period	17,298
Changes in fair value	32,284
Fair value of contracts at December 31, 2004	$(43,671)

Sources of Fair Value Gains/(Losses)

	Reorganized NRG Fair Value of Contracts at Period End as of December 31, 2004				
	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess of 5 Years	Total Fair Value
	(In thousands)				
Prices actively quoted	$47,131	$ 1,296	$ —	$ —	$ 48,427
Prices based on models and other valuation methods	1,371	(19,451)	(16,354)	(37,913)	(72,347)
Prices provided by other external sources	13,245	(1,643)	(6,500)	(24,853)	(19,751)
Total	$61,747	$(19,798)	$(22,854)	$(62,766)	$(43,671)

We may use a variety of financial instruments to manage our exposure to fluctuations in foreign currency exchange rates on our international project cash flows, interest rates on our cost of borrowing and energy and energy related commodities prices.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements and related disclosures in compliance with generally accepted accounting principles, or GAAP, requires the application of appropriate technical accounting rules and guidance as well as the use of estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies have not changed.

On an ongoing basis, we evaluate our estimates, utilizing historic experience, consultation with experts and other methods we consider reasonable. In any case, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Our significant accounting policies are summarized in Item 15 — Note 2 to the Consolidated Financial Statements. The following table identifies certain of the significant accounting policies listed in Item 15 — Note 2 to the Consolidated Financial Statements. The table also identifies the judgments required, uncertainties involved in the application of each and estimates that may have a material impact on our results of operations and statement of financial position. These policies, along with the underlying assumptions and judgments made by our management in their application, have a significant impact on our consolidated financial statements. We identify our most critical accounting policies as those that are the most pervasive and important to the portrayal of our financial position and results of operations, and that require the most difficult, subjective and/or complex judgments by management regarding estimates about matters that are inherently uncertain.

Accounting Policy	Judgments/Uncertainties Affecting Application
Fresh Start Reporting	• The determination of the enterprise value and the allocation to the underlying assets and liabilities are based on a number of estimates and assumptions, which are inherently subject to significant uncertainties and contingencies • Determination at Fresh Start date • Consolidation of entities remaining in bankruptcy • Valuation of emission credit allowances and power sales contracts • Valuation of debt instruments • Valuation of equity investments
Capitalization Practices	• Determination of beginning and ending of capitalization periods • Allocation of purchase prices to identified assets
Asset Valuation and Impairment	• Recoverability of investment through future operations • Regulatory and political environments and requirements • Estimated useful lives of assets • Environmental obligations and operational limitations • Estimates of future cash flows • Estimates of fair value (fresh start) • Judgment about triggering events
Revenue Recognition	• Customer/counter-party dispute resolution practices

Accounting Policy	Judgments/Uncertainties Affecting Application
	• Market maturity and economic conditions • Contract interpretation
Uncollectible Receivables	• Economic conditions affecting customers, counter-parties, suppliers and market prices • Regulatory environment and impact on customer financial condition • Outcome of litigation and bankruptcy proceedings
Derivative Financial Instruments	• Market conditions in the energy industry, especially the effects of price volatility on contractual commitments • Assumptions used in valuation models • Documentation requirements • Counter-party credit risk • Market conditions in foreign countries • Regulatory and political environments and requirements
Litigation Claims and Assessments	• Impacts of court decisions • Estimates of ultimate liabilities arising from legal claims
Income Taxes and Valuation Allowance for Deferred Tax Assets	• Ability of tax authority decisions to withstand legal challenges or appeals • Anticipated future decisions of tax authorities • Application of tax statutes and regulations to transactions. • Ability to utilize tax benefits through carrybacks to prior periods and carryforwards to future periods.
Discontinued Operations	• Consistent application • Determination of fair value (recoverability) • Recognition of expected gain or loss prior to disposition
Pension	• Accuracy of management assumptions • Accuracy of actuarial consultant assumptions
Stock-Based Compensation	• Accuracy of management assumptions used to determine the fair value of the stock options

Of all of the accounting policies identified in the above table, we believe that the following policies and the application thereof to be those having the most direct impact on our financial position and results of operations.

Fresh Start Reporting

In connection with the emergence from bankruptcy, we adopted Fresh Start in accordance with the requirements of SOP 90-7. The application of SOP 90-7 resulted in the creation of a new reporting entity. Under Fresh Start, the reorganization value of our company was allocated among our assets and liabilities on a basis substantially consistent with purchase accounting in accordance with SFAS No. 141, *"Business Combinations."*

The bankruptcy court in its confirmation order approved our plan of reorganization on November 24, 2003. Under the requirements of SOP 90-7, the Fresh Start date is determined to be the confirmation date unless significant uncertainties exist regarding the effectiveness of the bankruptcy order. Our plan of reorganization required completion of the Xcel Energy settlement agreement prior to emergence from bankruptcy. We believe this settlement agreement was a significant contingency and thus delayed the Fresh Start date until the Xcel Energy settlement agreement was finalized on December 5, 2003.

Under the requirements of Fresh Start, we adjusted our assets and liabilities, other than deferred income taxes, to their estimated fair values as of December 5, 2003. As a result of marking our assets and liabilities to their estimated fair values, we determined that there was no excess reorganization value to recognize as an intangible asset. Deferred taxes were determined in accordance with SFAS No. 109, *"Accounting for Income Taxes."* The net effect of all Fresh Start adjustments resulted in a gain of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations), which is reflected in the Predecessor Company's results for the period January 1, 2003 through December 5, 2003. The application of the Fresh Start provisions of SOP 90-7 created a new reporting entity having no retained earnings or accumulated deficit.

As part of the bankruptcy process we engaged an independent financial advisor to assist in the determination of the fair value of our reorganized enterprise value. The fair value calculation was based on management's forecast of expected cash flows from our core assets. Management's forecast incorporated forward commodity market prices obtained from a third party consulting firm. A discounted cash flow calculation was used to develop the enterprise value of Reorganized NRG, determined in part by calculating the weighted average cost of capital of the Reorganized NRG. The Discounted Cash Flow, or DCF, valuation methodology equates the value of an asset or business to the present value of expected future economic benefits to be generated by that asset or business. The DCF methodology is a "forward looking" approach that discounts all expected future economic benefits by a theoretical or observed discount rate. The independent financial advisor prepared a 30-year cash flow forecast using a discount rate of approximately 11%. The resulting reorganization enterprise value ranged from $5.5 billion to $5.7 billion. The independent financial advisor then subtracted our project-level debt and made several other adjustments to reflect the values of assets held for sale, excess cash and collateral requirements to estimate a range of Reorganized NRG equity value of between $2.2 billion and $2.6 billion.

In constructing our Fresh Start balance sheet upon our emergence from bankruptcy, we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Our reorganization value of approximately $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. The reorganization value represents the fair value of an entity before liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after restructuring. This value is consistent with the voting creditors and Court's approval of the Plan of Reorganization.

A separate plan of reorganization was filed for our Northeast Generating and South Central Generating entities that was confirmed by the bankruptcy court on November 25, 2003, and became effective on December 23, 2003, when the final conditions of the plan were completed. In connection with Fresh Start on December 5, 2003, we have accounted for these entities as if they had emerged from bankruptcy at the same time that we emerged, as we believe that we continued to maintain control over the Northeast Generating and South Central Generating facilities throughout the bankruptcy process.

Due to the adoption of Fresh Start upon our emergence from bankruptcy, the Reorganized NRG's post-fresh start balance sheet, statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are therefore not comparable in certain respects to the financial statements prior to the application of Fresh Start.

Capitalization Practices

Reorganized NRG

In connection with the emergence from bankruptcy, we adopted Fresh Start in accordance with the requirements of SOP 90-7. The application of SOP 90-7 resulted in the creation of a new reporting entity.

Under Fresh Start, the reorganization value of our company was allocated to our assets and liabilities on a basis substantially consistent with purchase accounting in accordance with SFAS No. 141. We engaged a valuation specialist to help us determine the fair value of our fixed assets. The valuations were based on forecast power prices and operating costs determined by us. The valuation specialist also determined the estimated remaining useful lives of our fixed assets.

Predecessor Company

For those assets that were being constructed by us, the carrying value reflects the application of our property, plant and equipment policies which incorporate estimates, assumptions and judgments by management relative to the capitalized costs and useful lives of our generating facilities. Interest incurred on funds borrowed to finance projects expected to require more than three months to complete is capitalized. Capitalization of interest is discontinued when the asset under construction is ready for our intended use or when construction is terminated. An insignificant amount of interest was capitalized during 2003. Development costs and capitalized project costs include third party professional services, permits and other costs that are incurred incidental to a particular project. Such costs are expensed as incurred until an acquisition agreement or letter of intent is signed, and our board of directors has approved the project. Additional costs incurred after this point are capitalized.

Impairment of Long Lived Assets

We evaluate property, plant and equipment and intangible assets for impairment whenever indicators of impairment exist. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the assets to the future net cash flows expected to be generated by the asset, through considering project specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operations. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets by factoring in the probability weighting of different courses of action available to us. Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. Assets to be disposed of are reported at the lower of the carrying amount or fair value less the cost to sell. For the year ended December 31, 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003 and for the year ended December 31, 2002, net income from continuing operations was reduced by $44.7 million, $0 million, $228.9 million and $2.5 billion, respectively, due to asset impairments. Asset impairment evaluations are by nature highly subjective.

Revenue Recognition and Uncollectible Receivables

We are primarily an electric generation company, operating a portfolio of majority-owned electric generating plants and certain plants in which our ownership is 50% or less which are accounted for under the equity method of accounting. We also produce thermal energy for sale to customers. Both physical and financial transactions are entered into to optimize the financial performance of our generating facilities. Electric energy revenue is recognized upon transmission to the customer. In regions where bilateral markets exist and physical delivery of electricity is common from our plants, we record revenue on a gross basis. In certain markets, which are operated/controlled by an independent system operator and in which we have entered into a netting agreement with the ISO, which results in our receiving a netted invoice, we have recorded purchased energy as an offset against revenues received upon the sale of such energy. Revenues derived from the buying and selling of electricity not sourced from our facilities are reported net. Capacity and ancillary revenue is recognized when contractually earned. Revenues from operations and maintenance services are recognized when the services are performed. We continually assess the collectibility of our receivables, and in the event we believe a receivable to be uncollectible, an allowance for doubtful accounts is recorded or, in the event of a contractual dispute, the receivable and corresponding revenue may be considered unlikely of recovery and not recorded in the financial statements until management is satisfied that it will be collected.

Derivative Financial Instruments

In January 2001, we adopted FAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities,"* or SFAS No. 133, as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149. SFAS No. 133, as amended, requires us to record all derivatives on the balance sheet at fair value. In some cases hedge accounting may apply. The criteria used to determine if hedge accounting treatment is appropriate are a) the designation of the hedge to an underlying exposure, b) whether or not the overall risk is being reduced and c) if there is correlation between the value of the derivative instrument and the underlying obligation. Formal documentation of the hedging relationship, the nature of the underlying risk, the risk management objective, and the means by which effectiveness will be assessed is created at the inception of the hedge. Changes in the fair value of non-hedge derivatives are immediately recognized in earnings. Changes in the fair value of derivatives accounted for as hedges are either recognized in earnings as an offset to the changes in the fair value of the related hedged assets, liabilities and firm commitments or for forecasted transactions, deferred and recorded as a component of accumulated other comprehensive income, or OCI, until the hedged transactions occur and are recognized in earnings. We primarily account for derivatives under SFAS No. 133, as amended, such as long-term power sales contracts, long-term gas purchase contracts and other energy related commodities and financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and to protect investments in fuel inventories. SFAS No. 133, as amended, also applies to interest rate swaps and foreign currency exchange rate contracts. The application of SFAS No. 133, as amended, results in increased volatility in earnings due to the recognition of unrealized gains and losses. In determining the fair value of these derivative/financial instruments we use estimates, various assumptions, judgment of management and when considered appropriate third party experts in determining the fair value of these derivatives.

Discontinued Operations

We classify our results of operations that either have been disposed of or are classified as held for sale as discontinued operations if both of the following conditions are met: (a) the operations and cash flows have been (or will be) eliminated from our ongoing operations as a result of the disposal transaction and (b) we will not have any significant continuing involvement in the operations of the component after the disposal transaction. Prior periods are restated to report the operations as discontinued.

Pensions

The determination of our obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. Our actuarial consultants use assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of pension obligation or expense recorded by us.

Stock-Based Compensation

Effective January 1, 2003, we adopted the fair value recognition provisions of SFAS Statement No. 123, *"Accounting for Stock-Based Compensation,"* or SFAS No. 123. In accordance with SFAS Statement No. 148, *"Accounting for Stock-Based Compensation — Transition and Disclosure,"* or SFAS No. 148, we adopted SFAS No. 123 under the prospective transition method which requires the application of the recognition provisions to all employee awards granted, modified, or settled after the beginning of the fiscal year in which the recognition provisions are first applied. The Black-Scholes option-pricing model is used for all non-qualified stock options.

Recent Accounting Developments

In November 2004, the Emerging Issue Task Force, or EITF, issued EITF No. 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* in Determining Whether to Report Discontinued Operations". EITF 03-13 clarifies the definition of cash flows of a component in which the seller engages in activities with the component after disposal, and significant continuing involvement in the operations of the component after the disposal transaction, and is effective for fiscal periods beginning after December 15, 2004. The adoption of this standard will not have a material effect on our consolidated financial position and results of operations.

In November 2004, the FASB issued SFAS No. 151, *"Inventory Costs — an amendment of ARB No. 43, Chapter 4"*. This statement amends the guidance in ARB No. 43, Chapter 4, "Inventory Pricing", and requires that idle facility expense, excessive spoilage, double freight, and rehandling costs be recognized as current-period charges regardless of whether they meet the criterion of "so abnormal" established by ARB No. 43. SFAS No. 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The adoption of this statement will not have a material effect on our consolidated financial position and results of operations.

In December 2004, the FASB issued SFAS No. 123R, *"Share-Based Payment"*, a revision to SFAS No. 123, *"Accounting for Stock-Based Compensation"*, which supersedes APB Opinion No. 25, *"Accounting for Stock Issued to Employees"* and its related implementation guidance. SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services, including obtaining employee services in share-based payment transactions. SFAS 123R applies to all awards granted after the required effective date and to awards modified, repurchased, or cancelled after that date. Adoption of the provisions of SFAS 123R is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. We have previously adopted SFAS No. 123, and we are currently in the process of evaluating the potential impact that the adoption of SFAS 123R will have on our consolidated financial position and results of operations.

In December 2004, the FASB issued two FASB Staff Positions, or FSPs, regarding the accounting implications of the American Jobs Creation Act of 2004 related to (1) the deduction for qualified domestic production activities (FSP FAS 109-1) and (2) the one-time tax benefit for the repatriation of foreign earnings (FSP FAS 109-2). In FSP FAS 109-1, *"Application of FASB Statement No. 109, "Accounting for Income Taxes," to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004"*, the Board decided that the deduction for qualified domestic production activities should be accounted for as a special deduction under FASB Statement No. 109, *"Accounting for Income Taxes"* and rejected an alternative view to treat it as a rate reduction. Accordingly, any benefit from the deduction should be reported in the period in which the deduction is claimed on the tax return. FSP FAS 109-2, *"Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004"*, addresses the appropriate point at which a company should reflect in its financial statements the effects of the one-time tax benefit on the repatriation of foreign earnings. Because of the proximity of the Act's enactment date to many companies' year-ends, its temporary nature, and the fact that numerous provisions of the Act are sufficiently complex and ambiguous, the Board decided that absent additional clarifying regulations, companies may not be in a position to assess the impact of the Act on their plans for repatriation or reinvestment of foreign earnings. Therefore, the Board provided companies with a practical exception to FAS 109's requirements by providing them additional time to determine the amount of earnings, if any, that they intend to repatriate under the Act's beneficial provisions. The Board confirmed, however, that upon deciding that some amount of earnings will be repatriated, a company must record in that period the associated tax liability, thereby making it clear that a company cannot avoid recognizing a tax liability when it has decided that some portion of its foreign earnings will be repatriated. We are currently in the process of evaluating the potential impact that the adoption of FSP FAS 109-1 and FSP FAS 109-2 will have on our consolidated financial position and results of operations.

Item 7A — *Quantitative and Qualitative Disclosures About Market Risk*

We are exposed to several market risks in our normal business activities. Market risk is the potential loss that may result from market changes associated with our "merchant" power generation or with an existing or forecasted financial or commodity transaction. The types of market risks we are exposed to are commodity price risk, interest rate risk and currency exchange risk. In order to manage these risks we utilize various fixed-price forward purchase and sales contracts, futures and option contracts traded on the New York Mercantile Exchange, and swaps and options traded in the over-the-counter financial markets to:

- Manage and hedge our fixed-price purchase and sales commitments;
- Manage and hedge our exposure to variable rate debt obligations,
- Reduce our exposure to the volatility of cash market prices; and
- Hedge our fuel requirements for our generating facilities.

Commodity Price Risk

Commodity price risks result from exposures to changes in spot prices, forward prices, volatilities in commodities, and correlations between various commodities, such as natural gas, electricity, coal and oil. A number of factors influence the level and volatility of prices for energy commodities and related derivative products. These factors include:

- Seasonal daily and hourly changes in demand,
- Extreme peak demands due to weather conditions,
- Available supply resources,
- Transportation availability and reliability within and between regions,
- Changes in the nature and extent of federal and state regulations.

As part of our overall portfolio, we manage the commodity price risk of our "merchant" generation by entering into various derivative or non-derivative instruments to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel. These instruments include forward purchase and sale contracts, futures and option contracts traded on the New York Mercantile Exchange, and swaps and options traded in the over-the-counter financial markets. The portion of forecasted transactions hedged may vary based upon management's assessment of market, weather, operational, and other factors.

While some of the contracts we use to manage risk represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. We use our best estimates to determine the fair value of commodity and derivative contracts we hold and sell. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is likely that future market prices could vary from those used in recording mark-to-market derivative instrument valuation, and such variations could be material.

We measure the sensitivity of our portfolio to potential changes in market prices using value at risk. Value at risk is a statistical model that attempts to predict risk of loss based on market price volatility. We calculate value at risk using a variance/covariance technique that models positions using a linear approximation of their value. Our value at risk calculation includes mark-to-market and non mark-to-market energy assets and liabilities.

We utilize a diversified value at risk model to calculate the estimate of potential loss in the fair value of our energy assets and liabilities including generation assets, load obligations and bilateral physical and financial transactions. The key assumptions for our diversified model include (1) a lognormal distribution of price returns, (2) one-day holding period, (3) a 95% confidence interval, (4) a rolling 24-month forward looking period and (5) market implied price volatilities and historical price correlations.

This model encompasses the following generating regions: ENTERGY, NEPOOL, NYPP, PJM, WSCC and MAIN. The estimated maximum potential loss in fair value of our commodity portfolio, including generation assets, load obligations and bilateral physical and financial transaction, calculated using the diversified VAR model is as follows:

	(In millions)
Year end December 31, 2004	$26.7
Average	40.3
High	53.4
Low	26.7
Year end December 31, 2003	37.1
Average	45.7
High	53.0
Low	37.1

In order to provide additional information for comparative purposes to our peers we also utilize value at risk to model the estimate of potential loss of financial derivative instruments included in derivative instruments valuation assets and liabilities. This estimation includes those energy contracts accounted for as a hedge under SFAS No. 133, as amended. The estimated maximum potential loss in fair value of the financial derivative instruments calculated using the diversified VAR model as of December 31, 2004 is $17.6 million.

Due to the inherent limitations of statistical measures such as value at risk, the relative immaturity of the competitive markets for electricity and related derivatives, and the seasonality of changes in market prices, the value at risk calculation may not capture the full extent of commodity price exposure. Additionally, actual changes in the value of options may differ from the value at risk calculated using a linear approximation inherent in our calculation method. As a result, actual changes in the fair value of mark-to market energy assets and liabilities could differ from the calculated value at risk, and such changes could have a material impact on our financial results.

Interest Rate Risk

We are exposed to fluctuations in interest rates through our issuance of fixed rate and variable rate debt. Exposures to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility and result in primarily fixed rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. Our risk management policy allows us to reduce interest rate exposure from variable rate debt obligations.

As of December 31, 2004, we had various interest rate swap agreements with notional amounts totaling approximately $1.3 billion. If the swaps had been discontinued on December 31, 2004, we would have owed the counter-parties approximately $35.6 million. Based on the investment grade rating of the counter-parties, we believe that our exposure to credit risk due to nonperformance by the counter-parties to our hedging contracts is insignificant.

We have both long and short-term debt instruments that subject us to the risk of loss associated with movements in market interest rates. As of December 31, 2004, a 100 basis point change in interest rates would result in a $5.7 million change in interest expense.

At December 31, 2004, the fair value of our long-term debt was $3.9 billion, compared with the carrying amount of $3.8 billion. We estimate that a 1% decrease in market interest rates would have increased the fair value of our long-term debt by $76.3 million.

Currency Exchange Risk

We expect to continue to be subject to currency risks associated with foreign denominated distributions from our international investments. In the normal course of business, we may receive distributions denominated in the Euro, Australian Dollar, British Pound and the Brazilian Real. We have historically engaged in a strategy of hedging foreign denominated cash flows through a program of matching currency inflows and outflows, and to the extent required, fixing the U.S. Dollar equivalent of net foreign denominated distributions with currency forward and swap agreements with highly credit worthy financial institutions. We would expect to enter into similar transactions in the future if management believes it to be appropriate.

As of December 31, 2004, neither we, nor any of our consolidating subsidiaries, had any outstanding foreign currency exchange contracts.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counter-parties pursuant to the terms of their contractual obligations. We monitor and manage the credit risk of NRG Energy, Inc. and its subsidiaries through credit policies which include an (i) established credit approval process, (ii) daily monitoring of counter-party credit limits, (iii) the use of credit mitigation measures such as margin, collateral, credit derivatives or prepayment arrangements, (iv) the use of payment netting agreements and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counter-party. Risks surrounding counter-party performance and credit could ultimately impact the amount and timing of expected cash flows. We have credit protection within various agreements to call on additional collateral support if necessary. As of December 31, 2004, we held collateral support of $155.5 million from counterparties.

Additionally NRG has concentrations of suppliers and customers among electric utilities, energy marketing and trading companies and regional transmission operators. These concentrations of counter-parties may impact NRG's overall exposure to credit risk, either positively or negatively, in that counter-parties may be similarly affected by changes in economic, regulatory and other conditions.

Item 8 — *Financial Statements and Supplementary Data*

The financial statements and schedules are listed in Part IV, Item 15 of this Form 10-K.

Item 9 — *Changes in and Disagreements with Accountants on Accounting and Financial Disclosures*

None.

Item 9A — *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer, principal financial officer and principal accounting officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Based on this evaluation, our principal executive officer, principal financial officer and principal accounting officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this annual report on Form 10-K.

There have not been any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter that have materially affected, or are reasonably likely to materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B — *Other Information*

The following disclosure would otherwise have been filed on Form 8-K under the caption "Item 1.01. Entry into a Material Definitive Agreement." On December 7, 2004, the Board of Directors approved the following additional director compensation: an additional $10,000 for members of the Audit Committee due to the extraordinary number of meetings (19) held in 2004 and an additional $5,000 for members of the Board of

Directors who served on a special committee in connection with the sale of shares by MatlinPatterson Global Opportunities Partners L.P. and one of its affiliates to NRG Energy.

PART III

Item 10 — *Directors and Executive Officers of the Registrant*

NRG Energy has adopted a code of ethics entitled "NRG Code of Conduct" that applies to directors, officers and employees, including the chief executive officer and senior financial officers of NRG Energy, which may be viewed through NRG Energy's website at http://www.nrgenergy.com/investor/corpgov/.htm. NRG Energy also elects to disclose the information required by Form 8-K, Item 5.05, "Amendments to the registrant's code of ethics, or waiver of a provision of the code of ethics," through this website and such information will remain available on this website for at least a 12-month period. A copy of the "NRG Code of Conduct" is available in print to any shareholder who requests it.

Other information required by this Item will be contained in our definitive Proxy Statement for our 2005 Annual Meeting of Stockholders, to be filed on or before May 1, 2005, and such information is incorporated herein by reference.

Item 11 — *Executive Compensation*

Information required by this Item will be contained in our definitive Proxy Statement for our 2005 Annual Meeting of Stockholders, to be filed on or before May 1, 2005, and such information is incorporated herein by reference.

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

Information required by this Item will be contained in our definitive Proxy Statement for our 2005 Annual Meeting of Stockholders, to be filed on or before May 1, 2005, and such information is incorporated herein by reference.

Item 13 — *Certain Relationships and Related Transactions*

Information required by this Item will be contained in our definitive Proxy Statement for our 2005 Annual Meeting of Stockholders, to be filed on or before May 1, 2005, and such information is incorporated herein by reference.

Item 14 — *Principal Accountant Fees and Services*

Information required by this Item will be contained in our definitive Proxy Statement for our 2005 Annual Meeting of Stockholders, to be filed on or before May 1, 2005, and such information is incorporated herein by reference.

PART IV

Item 15 — *Exhibits and Financial Statement Schedules*

(a)(1) Financial Statements

The following consolidated financial statements of NRG Energy and related notes thereto, together with the reports thereon of KPMG LLP are included herein:

Consolidated Statement of Operations — Year ended December 31, 2004 (Reorganized NRG)

Consolidated Balance Sheet — December 31, 2004 (Reorganized NRG)

Consolidated Statement of Cash Flows — Year ended December 31, 2004 (Reorganized NRG)

Consolidated Statement of Stockholders' Equity/(Deficit) and Comprehensive Income/(Loss) — Year ended December 31, 2004 (Reorganized NRG)

Notes to Consolidated Financial Statements

The following consolidated financial statements of NRG Energy and related notes thereto, together with the reports thereon of PricewaterhouseCoopers LLP are included herein:

Consolidated Statements of Operations — The period December 6, 2003 to December 31, 2003 (Reorganized NRG), the period January 1, 2003 to December 5, 2003 and the Year ended December 31, 2002 (Predecessor Company)

Consolidated Balance Sheet — December 31, 2003 (Reorganized NRG)

Consolidated Statements of Cash Flows — The period December 6, 2003 to December 31, 2003 (Reorganized NRG), the period January 1, 2003 to December 5, 2003 and the Year ended December 31, 2002 (Predecessor Company)

Consolidated Statements of Stockholders' Equity/(Deficit) and Comprehensive Income/(Loss) — The period December 6, 2003 to December 31, 2003 (Reorganized NRG), the period January 1, 2003 to December 5, 2003 and the Year ended December 31, 2002 (Predecessor Company)

Notes to Consolidated Financial Statements

(a)(2) Financial Statement Schedule

The following Consolidated Financial Statement Schedule of NRG Energy is filed as part of Item 15(d) of this report and should be read in conjunction with the Consolidated Financial Statements.

Report of Independent Registered Public Accounting Firm on Financial Statement Schedule.

Schedule II — Valuation and Qualifying Accounts

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions or are inapplicable, and therefore, have been omitted.

(a)(3) *Exhibits:* See Exhibit Index submitted as a separate section of this report.

(b) Exhibits

(c) Financial Statement Schedule

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer, principal financial officer and principal accounting officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control — Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2004.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by KPMG LLP, our independent registered public accounting firm, as stated in its report which is included in this Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
NRG Energy, Inc.:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that NRG Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2004, based on "criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO)". NRG Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, management's assessment that NRG Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on "criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO)". Also, in our opinion, NRG Energy, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on "criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO)".

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of NRG Energy, Inc. and subsidiaries as of December 31, 2004, and the related consolidated statements of operations, stockholders' equity/(deficit) and comprehensive income/(loss), and cash flows for the year then ended December 31, 2004, and our report dated March 29, 2005 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania
March 29, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
NRG Energy, Inc.:

We have audited the accompanying consolidated balance sheet of NRG Energy, Inc. and subsidiaries as of December 31, 2004, and the related consolidated statements of operations, stockholders' equity/(deficit) and comprehensive income/(loss), and cash flows for the year then ended. In connection with our audit of the consolidated financial statements, we also have audited the financial statement schedule "Schedule II Valuation and Qualifying Accounts." These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of NRG Energy, Inc. and subsidiaries as of December 31, 2004, and the results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of NRG Energy, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2004, based on "criteria established in Internal Control — Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO)", and our report dated March 29, 2005 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania
March 29, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of NRG Energy, Inc.:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, cash flows and stockholders' equity/(deficit) and comprehensive income/(loss) present fairly, in all material respects, the financial position of NRG Energy, Inc. and its subsidiaries (Reorganized NRG) at December 31, 2003 and the results of their operations and their cash flows for the period from December 6, 2003 to December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Notes 1 and 2 to the consolidated financial statements, the United States Bankruptcy Court for the Southern District of New York confirmed the NRG Energy, Inc. Plan of Reorganization on November 24, 2003. Confirmation of the plan resulted in the discharge of all claims against the Company that arose before May 14, 2003 and substantially alters rights and interests of equity security holders as provided for in the plan. The NRG Energy, Inc. Plan of Reorganization was substantially consummated on December 5, 2003, and NRG Energy, Inc. emerged from bankruptcy. In connection with its emergence from bankruptcy, NRG Energy, Inc. adopted fresh start accounting as of December 5, 2003.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 10, 2004, except as to Notes 6, 23, and 33, which are as of December 6, 2004

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of NRG Energy, Inc.:

In our opinion, the accompanying consolidated statements of operations, cash flows and stockholders' equity/(deficit) and comprehensive income/(loss) present fairly, in all material respects, the results of operations and cash flows of NRG Energy, Inc. and its subsidiaries (Predecessor Company) for the period from January 1, 2003 to December 5, 2003, and for the year ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 1 and 2 to the consolidated financial statements, the Company filed a petition on May 14, 2003 with the United States Bankruptcy Court for the Southern District of New York for reorganization under the provisions of Chapter 11 of the Bankruptcy Code. NRG Energy, Inc.'s Plan of Reorganization was substantially consummated on December 5, 2003 and Reorganized NRG emerged from bankruptcy. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 10, 2004, except as to Notes 6, 23, and 33, which are as of December 6, 2004

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003	Year Ended December 31, 2002
	(In thousands, except per share amounts)			
Operating Revenues				
Revenues from majority-owned operations	$2,361,424	$138,490	$ 1,798,387	$ 1,938,293
Operating Costs and Expenses				
Cost of majority-owned operations	1,494,336	95,541	1,355,909	1,332,446
Depreciation and amortization	209,295	11,808	218,843	207,027
General, administrative and development	211,240	12,518	170,330	218,852
Other charges (credits)				
Corporate relocation charges	16,167	—	—	—
Reorganization items	(13,390)	2,461	197,825	—
Restructuring and impairment charges	44,661	—	237,575	2,563,060
Fresh start reporting adjustments	—	—	(4,118,636)	—
Legal settlement	—	—	462,631	—
Total operating costs and expenses	1,962,309	122,328	(1,475,523)	4,321,385
Operating Income/(Loss)	399,115	16,162	3,273,910	(2,383,092)
Other Income/(Expense)				
Minority interest in earnings of consolidated subsidiaries	(1,045)	(134)	—	—
Equity in earnings of unconsolidated affiliates	159,825	13,521	170,901	68,996
Write downs and losses on sales of equity method investments	(16,270)	—	(147,124)	(200,472)
Other income, net	26,565	97	19,209	11,431
Refinancing expenses	(71,569)	—	—	—
Interest expense	(269,364)	(18,902)	(329,889)	(452,182)
Total other expense	(171,858)	(5,418)	(286,903)	(572,227)
Income/(Loss) From Continuing Operations Before Income Taxes	227,257	10,744	2,987,007	(2,955,319)
Income Tax Expense/(Benefit)	65,112	(661)	37,929	(166,867)
Income/(Loss) From Continuing Operations	162,145	11,405	2,949,078	(2,788,452)
Income/(Loss) on Discontinued Operations, net of Income Taxes	23,472	(380)	(182,633)	(675,830)
Net Income/(Loss)	$ 185,617	$ 11,025	$ 2,766,445	$(3,464,282)
Weighted Average Number of Common Shares Outstanding — Basic	99,616	100,000		
Income From Continuing Operations per Weighted Average Common Share — Basic	$ 1.62	$ 0.11		
Income From Discontinued Operations per Weighted Average Common Share — Basic	0.24	—		
Net Income per Weighted Average Common Share — Basic	$ 1.86	$ 0.11		
Weighted Average Number of Common Shares Outstanding — Diluted	100,371	100,060		
Income From Continuing Operations per Weighted Average Common Share — Diluted	$ 1.62	$ 0.11		
Income From Discontinued Operations per Weighted Average Common Share — Diluted	0.23	—		
Net Income per Weighted Average Common Shares — Diluted	$ 1.85	$ 0.11		

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	Reorganized NRG December 31, 2004	December 31, 2003
	(In thousands)	
ASSETS		
Current Assets		
Cash and cash equivalents	$1,110,045	$ 551,223
Restricted cash	112,824	116,067
Accounts receivable-trade, less allowance for doubtful accounts of $1,011 and $0	272,101	201,921
Xcel Energy settlement receivable	—	640,000
Current portion of notes receivable and other investments — affiliates	—	200
Current portion of notes receivable and other investments	85,447	65,141
Income taxes receivable	37,484	—
Inventory	248,010	194,926
Derivative instruments valuation	79,759	772
Prepayments and other current assets	169,608	222,138
Deferred income taxes	—	1,850
Current assets — discontinued operations	3,010	119,601
Total current assets	2,118,288	2,113,839
Property, Plant and Equipment		
In service	3,564,658	3,885,465
Under construction	17,429	139,171
Total property, plant and equipment	3,582,087	4,024,636
Less accumulated depreciation	(207,536)	(11,800)
Net property, plant and equipment	3,374,551	4,012,836
Other Assets		
Equity investments in affiliates	734,950	737,998
Notes receivable and other investments, less current portion — affiliates, less reserve for uncollectible notes receivable of $4,402 and $0	128,046	130,152
Notes receivable and other investments, less current portion, less reserve for uncollectible notes receivable of $3,794 and $0	676,476	691,444
Decommissioning fund investments	4,954	4,809
Intangible assets, net of accumulated amortization of $55,010 and $5,212	294,350	432,361
Debt issuance costs, net of accumulated amortization of $3,635 and $454	48,485	74,337
Derivative instruments valuation	41,787	59,907
Funded letter of credit	350,000	250,000
Other assets	58,141	114,131
Non-current assets — discontinued operations	—	623,173
Total other assets	2,337,189	3,118,312
Total Assets	$7,830,028	$9,244,987

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS — (Continued)

	Reorganized NRG	
	December 31, 2004	December 31, 2003
	(In thousands)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 512,252	$ 801,229
Short-term debt	—	19,019
Accounts payable — trade	166,131	158,646
Accounts payable — affiliates	5,591	3,092
Accrued income taxes	—	16,095
Accrued property, sales and other taxes	11,134	22,301
Accrued salaries, benefits and related costs	35,206	19,330
Accrued interest	11,057	8,982
Derivative instruments valuation	16,772	429
Deferred income taxes	334	—
Creditor pool obligation	—	540,000
Other bankruptcy settlement	175,576	220,000
Other current liabilities	152,526	102,861
Current liabilities — discontinued operations	1,362	114,197
Total current liabilities	1,087,941	2,026,181
Other Liabilities		
Long-term debt and capital leases	3,253,866	3,327,782
Deferred income taxes	134,325	149,493
Postretirement and other benefit obligations	116,383	105,946
Derivative instruments valuation	148,445	153,503
Other long-term obligations	389,719	480,938
Non-current liabilities — discontinued operations	1,081	558,884
Total non-current liabilities	4,043,819	4,776,546
Total liabilities	5,131,760	6,802,727
Minority interest	6,104	5,004
Commitments and Contingencies		
Stockholders' Equity		
4% Convertible perpetual preferred stock; $.01 par value; 10,000,000 shares authorized, 420,000 issued and outstanding at December 31, 2004 (shown at liquidation value net of issuance costs)	406,359	
Common stock; $.01 par value; 500,000,000 shares authorized; 100,041,935 and 100,000,000 shares issued at December 31, 2004 and 2003; 87,041,935 and 100,000,000 outstanding at December 31, 2004 and 2003	1,000	1,000
Additional paid-in capital	2,417,021	2,403,429
Retained earnings	196,642	11,025
Less treasury stock, at cost — 13,000,000 shares	(405,312)	—
Accumulated other comprehensive income	76,454	21,802
Total stockholders' equity	2,692,164	2,437,256
Total Liabilities and Stockholders' Equity	$7,830,028	$9,244,987

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
Cash Flows from Operating Activities				
Net income/(loss)	$ 185,617	$ 11,025	$ 2,766,445	$(3,464,282)
Adjustments to reconcile net income/(loss) to net cash provided by operating activities Distributions in excess of (less than) equity earnings of unconsolidated affiliates	(1,062)	2,229	(41,472)	(22,252)
Depreciation and amortization	214,620	13,041	256,700	286,623
Reserve for note and interest receivable	11,737	—	—	—
Amortization of financing costs and debt discount/(premium)	27,659	2,242	17,640	28,367
Write-off of deferred financing costs due to refinancings	42,137	—	—	—
Write downs and losses on sales of equity method investments	16,270	—	146,938	196,192
Deferred income taxes and investment tax credits	57,238	(3,262)	(1,893)	(230,134)
Unrealized (gains)/losses on derivatives	(73,792)	3,774	(34,616)	(2,743)
Minority interest	1,046	204	2,177	(19,325)
Amortization of power contracts and emission credits	51,652	(13,431)	—	(89,415)
Amortization of unearned equity compensations	13,592	—	—	—
Restructuring and impairment charges	44,661	—	408,377	3,144,509
Fresh start reporting adjustments	—	—	(3,895,541)	—
Gain on sale of discontinued operations	(22,419)	—	(186,331)	(2,814)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions				
Accounts receivable, net	(51,471)	18,030	28,261	(13,216)
Xcel Energy settlement receivable	640,000	—	—	—
Inventory	(55,613)	11,054	14,128	42,596
Prepayments and other current assets	48,772	(9,504)	(36,812)	(58,368)
Accounts payable	6,905	(40,095)	648,646	325,949
Accrued expenses	(21,163)	(66,673)	217,356	249,940
Creditor pool obligation payments	(540,000)	—	—	—
Other current liabilities	7,242	(510,867)	(22,797)	47,692
Other assets and liabilities	40,365	(6,642)	(48,697)	10,723
Net Cash Provided (Used) by Operating Activities	643,993	(588,875)	238,509	430,042
Cash Flows from Investing Activities				
Proceeds from sale of discontinued operations	252,676	—	18,612	160,791
Proceeds from sale of investments	50,693	—	107,174	68,517
Proceeds from sale of turbines	—	—	70,717	—
Decrease/(increase) in restricted cash and trust funds	(26,443)	375,272	(266,466)	(197,802)
Decrease/(increase) in notes receivable	25,109	1,182	(1,653)	(209,244)
Capital expenditures	(114,360)	(10,560)	(113,502)	(1,439,733)
Investments in projects	(2,990)	(2,522)	(561)	(63,996)
Net Cash Provided (Used) by Investing Activities	184,685	363,372	(185,679)	(1,681,467)
Cash Flows from Financing Activities				
Proceeds from issuance of preferred stock	406,359	—	—	—
Proceeds from issuance of stock	—	—	—	4,065
Purchase of treasury stock	(405,312)	—	—	—
Capital contributions from parent	—	—	—	500,000
Net borrowings under line of credit agreement	—	—	—	790,000
Proceeds from issuance of long-term debt	1,332,671	2,450,000	39,988	1,086,770
Deferred debt issuance costs	(25,506)	(74,795)	(18,540)	—
Funded letter of credit	(100,000)	(250,000)	—	—
Principal payments on short and long-term debt	(1,491,946)	(1,731,932)	(51,392)	(931,505)
Net Cash Provided (Used) by Financing Activities	(283,734)	393,273	(29,944)	1,449,330
Effect of Exchange Rate Changes on Cash and Cash Equivalents	3,007	(13,562)	(22,276)	24,950
Change in Cash from Discontinued Operations	10,871	1,033	34,512	51,267
Net Increase in Cash and Cash Equivalents	558,822	155,241	35,122	274,122
Cash and Cash Equivalents at Beginning of Period	551,223	395,982	360,860	86,738
Cash and Cash Equivalents at End of Period	$ 1,110,045	$ 551,223	$ 395,982	$ 360,860

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY/(DEFICIT) AND COMPREHENSIVE INCOME/(LOSS)

	Class A Common		Common		Additional Paid-In Capital	Retained Earnings/ (Deficit)	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Total Stockholders' Equity/ (Deficit)
	Stock	Shares	Stock	Shares					
					(In thousands)				
Balances at December 31, 2001 (Predecessor Company)	$ 1,476	147,605	$509	50,939	$ 1,713,984	$ 635,349	$—	$(114,189)	$ 2,237,129
Net loss						(3,464,282)			(3,464,282)
Foreign currency translation adjustments and other								64,054	64,054
Deferred unrealized loss on derivatives, net								(44,823)	(44,823)
Comprehensive loss for 2002									(3,445,051)
Contribution from parent					502,874				502,874
Issuance of common stock			6	591	8,843				8,849
Impact of exchange offer	(1,476)	(147,605)	(515)	(51,530)	1,991				—
Balances at December 31, 2002 (Predecessor Company)	$ —	—	$ —	—	$ 2,227,692	$(2,828,933)	$—	$ (94,958)	$ (696,199)

	Serial Preferred		Common		Additional Paid-In Capital	Retained Earnings/ (Deficit)	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Total Stockholders' Equity/ (Deficit)
	Stock	Shares	Stock	Shares					
					(In thousands)				
Balances at December 31, 2002 (Predecessor Company)	$ —	—	$ —	—	$ 2,227,692	$(2,828,933)	$ —	$(94,958)	$ (696,199)
Net income						2,766,445			2,766,445
Foreign currency translation adjustments and other								127,754	127,754
Deferred unrealized loss on derivatives, net								(31,363)	(31,363)
Comprehensive income for the period from January 1, 2003 through December 5, 2003									2,862,836
Effects of reorganization					(2,227,692)	62,488		(1,433)	(2,166,637)
Issuance of common stock			1,000	100,000	2,403,000				2,404,000
Balances at December 5, 2003 (Predecessor Company)	$ —	—	$1,000	100,000	$ 2,403,000	$ —	$ —	$ —	$ 2,404,000
Net income						11,025			11,025
Foreign currency translation adjustments and other								22,325	22,325
Deferred unrealized loss on derivatives, net								(523)	(523)
Comprehensive income for the period from December 6, 2003 through December 31, 2003									32,827
Equity based compensation					429				429
Balances at December 31, 2003 (Reorganized NRG)	$ —	—	$1,000	100,000	$ 2,403,429	$ 11,025	$ —	$ 21,802	$ 2,437,256
Net income						185,617			185,617
Foreign currency translation adjustments and other								46,660	46,660
Deferred unrealized loss on derivatives, net								7,992	7,992
Comprehensive income for 2004									240,269
Equity based compensation				42	13,592				13,592
Issuance of preferred stock	406,359	420,000							406,359
Purchase of treasury stock				(13,000)			(405,312)		(405,312)
Balances at December 31, 2004 (Reorganized NRG)	$406,359	420,000	$1,000	87,042	$ 2,417,021	$ 196,642	$(405,312)	$ 76,454	$ 2,692,164

See notes to consolidated financial statements.

Note 1 — Organization

General

NRG Energy, Inc., or "NRG Energy", the "Company", "we", "our", or "us" is a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities, the transacting in and trading of fuel and transportation services and the marketing and trading of energy, capacity and related products in the United States and internationally. We have a diverse portfolio of electric generation facilities in terms of geography, fuel type and dispatch levels. Our principal domestic generation assets consist of a diversified mix of natural gas-, coal- and oil-fired facilities, representing approximately 40%, 31% and 29% of our total domestic generation capacity, respectively. In addition, 23% of our domestic generating facilities have dual- or multiple-fuel capacity, which may allow plants to dispatch with the lowest cost fuel option.

We seek to maximize operating income through the generation of energy, marketing and trading of energy, capacity and ancillary services into spot, intermediate and long-term markets and the effective transacting in and trading of fuel supplies and transportation-related services. We perform our own power marketing (except with respect to our West Coast Power and Rocky Road affiliates), which is focused on maximizing the value of our North American and Australian assets through the pursuit of asset-focused power and fuel marketing and trading activities in the spot, intermediate and long-term markets. Our principal objectives are the management and mitigation of commodity market risk, the reduction of cash flow volatility over time, the realization of the full market value of the asset base, and adding incremental value by using market knowledge to effectively trade positions associated with our asset portfolio. Additionally, we work with markets, independent system operators and regulators to promote market designs that provide adequate long-term compensation for existing generation assets and to attract the investment required to meet future generation needs.

As of December 31, 2004, we owned interests in 52 power projects in five countries having an aggregate net generation capacity of approximately 15,400 MW. Approximately 7,900 MW of our capacity consisted of merchant power plants in the Northeast region of the United States. Certain of these assets are located in transmission constrained areas, including approximately 1,400 MW of "in-city" New York City generation capacity and approximately 750 MW of southwest Connecticut generation capacity. We also own approximately 2,500 MW of capacity in the South Central region of the United States, with approximately 1,900 MW of that capacity supported by long-term power purchase agreements.

As of December 31, 2004, our assets in the West Coast region of the United States consisted of approximately 1,300 MW of capacity with the majority of such capacity owned via our 50% interest in West Coast Power LLC, or West Coast Power. Our assets in the West Coast region were supported by a power purchase agreement with the California Department of Water Resources that expired on December 31, 2004. One-year term reliability must-run, or RMR, agreements with the California Independent System Operator for approximately 568 MW in the San Diego area have been renewed for 2005. On January 1, 2005, a new RMR agreement for the 670 MW gross capacity of the West Coast Power El Segundo generating facility became effective. In January 2005, that generating facility entered into a tolling agreement for its entire gross generating capacity of 670 MW commencing May 1, 2005 and extending through December 31, 2005. During the term of this agreement, the purchaser will be entitled to primary energy dispatch right for the facility's generating capacity. The agreement is subject to the amendment of the El Segundo RMR agreement to switch to RMR Condition I and to otherwise allow the purchaser to exercise its primary dispatch rights under this agreement while preserving Cal ISO's ability to call on the El Segundo facility as a reliability resource under the RMR agreement, if necessary. Approximately 265 MW of capacity at the Long Beach generating facility was retired January 1, 2005.

We own approximately 1,600 MW of net generating capacity in other regions of the U.S. We also own interests in plants having a net generation capacity of approximately 2,100 MW in various international markets, including Australia, Europe and Brazil. We operate substantially all of our generating assets, including the West Coast Power plants.

We were incorporated as a Delaware corporation on May 29, 1992. In March 2004, our common stock was listed on the New York Stock Exchange under the symbol "NRG". Our headquarters and principal executive offices are located at 211 Carnegie Center, Princeton, New Jersey 08540. Our telephone number is (609) 524-4500. The address of our website is www.nrgenergy.com. Our recent annual reports, quarterly reports, current reports and other periodic filings are available free of charge through our website.

We were formed in 1992 as the non-utility subsidiary of Northern States Power Company, or NSP, which was itself merged into New Century Energies, Inc. to form Xcel Energy, Inc., or Xcel Energy, in 2000. While owned by NSP and later by Xcel Energy, we pursued an aggressive high growth strategy focused on power plant acquisitions, high leverage and aggressive development, including site development and turbine orders. In 2002, a number of factors, most notably the aggressive prices paid by us for our acquisitions of turbines, development projects and plants, combined with the overall downturn in the power generation industry, triggered a series of credit rating downgrades which, in turn, precipitated a severe liquidity crisis at the Company. From May 14 to December 23, 2003, we and a number of our subsidiaries undertook a comprehensive reorganization and restructuring under chapter 11 of the United States Bankruptcy Code. With the exception of one subsidiary that remains in bankruptcy to effect its liquidation, all NRG entities had emerged from chapter 11 as of December 31, 2004.

As part of our reorganization, Xcel Energy relinquished its ownership interest in us, and we became an independent public company. We no longer have any material affiliation or relationship with Xcel Energy. As part of the reorganization, we eliminated approximately $5.2 billion of corporate level bank and bond debt and approximately $1.3 billion of additional claims and disputes by distributing a combination of equity and $1.04 billion in cash to our unsecured creditors.

As part of our restructuring, on December 23, 2003, we used the proceeds of a new $1.25 billion offering of 8% second priority senior secured notes due 2013, and borrowings under a new $1.45 billion secured credit facility, to retire approximately $1.7 billion of project-level debt. In January 2004, we used proceeds of a tack-on bond offering of the same notes to prepay $503.5 million of the outstanding borrowings under the secured credit facility.

In 2004, we completed our post-confirmation bankruptcy initiatives, including the liquidation of the chapter 11 subsidiaries deemed to be of no value to NRG Energy (LSP-Nelson Energy LLC and NRG Nelson Turbines LLC); the collection and distribution to creditors of amounts owing by our pre-bankruptcy parent company, Xcel Energy, Inc., under the plan of reorganization and related documents; and the settlement of several large disputed claims. We are still litigating or seeking to settle a number of unresolved disputed claims, for which we believe we have established an adequate disputed claims reserve pursuant to the NRG plan of reorganization. In all other respects, the reorganization process was completed in 2004.

On December 24, 2004, we entered into an amendment and restatement of our $1.45 billion seven-year secured credit facility, recasting it as a $950 million seven-year secured credit facility with more favorable covenants and interest rates, scheduled to expire in December 2011. On December 27, 2004, we completed the issuance of $420 million of perpetual convertible preferred stock, and used the proceeds to redeem $375 million of our 8% senior secured notes on February 4, 2005. In January 2005 and in March 2005, we purchased an additional $25 million and $15.8 million, respectively, of the notes.

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

Between May 14, 2003 and December 5, 2003, we operated as a debtor-in-possession under the supervision of the bankruptcy court. Our financial statements for reporting periods within that timeframe were prepared in accordance with the provisions of Statement of Position 90-7, *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code",* or SOP 90-7.

For financial reporting purposes, close of business on December 5, 2003, represents the date of our emergence from bankruptcy. As used herein, the following terms refer to the Company and its operations:

"Predecessor Company"	The Company, pre-emergence from bankruptcy The Company's operations prior to December 6, 2003
"Reorganized NRG"	The Company, post-emergence from bankruptcy The Company's operations, December 6, 2003-December 31, 2004

In January 2003, the FASB issued FASB Interpretation No. 46, *"Consolidation of Variable Interest Entities,"* or FIN No. 46. FIN No. 46 requires an enterprise's consolidated financial statements to include subsidiaries in which the enterprise has a controlling interest. In December 2003, the FASB has published a revision to Interpretation 46, or FIN 46R, to clarify some of the provisions of FASB Interpretation No. 46, *"Consolidation of Variable Interest Entities,"* and to exempt certain entities from its requirements. As required by SOP 90-7, we adopted FIN No. 46R as of the adoption of Fresh Start. The nature of the operations consolidated consisted of hydropower facilities on the East Coast.

The consolidated financial statements include our accounts and operations and those of our subsidiaries in which we have a controlling interest. All significant intercompany transactions and balances have been eliminated in consolidation. Accounting policies for all of our operations are in accordance with accounting principles generally accepted in the United States of America. As discussed in Note 13, we have investments in partnerships, joint ventures and projects. Earnings from equity in international investments are recorded net of foreign income taxes.

Fresh Start Reporting

In accordance with SOP 90-7, certain companies qualify for fresh start reporting in connection with their emergence from bankruptcy. Fresh start reporting is appropriate on the emergence from chapter 11 if the reorganization value of the assets of the emerging entity immediately before the date of confirmation is less than the total of all post-petition liabilities and allowed claims, and if the holders of existing voting shares immediately before confirmation receive less than 50 percent of the voting shares of the emerging entity. We met these requirements and adopted Fresh Start reporting resulting in the creation of a new reporting entity designated as Reorganized NRG.

The bankruptcy court issued a confirmation order approving our plan of reorganization on November 24, 2003. Under the requirements of SOP 90-7, the Fresh Start date is determined to be the confirmation date unless significant uncertainties exist regarding the effectiveness of the bankruptcy order. Our plan of reorganization required completion of the Xcel Energy settlement agreement prior to emergence from bankruptcy. The Xcel Energy settlement agreement was entered into on December 5, 2003. We believe this settlement agreement was a significant contingency and thus delayed the Fresh Start date until the Xcel Energy settlement agreement was finalized on December 5, 2003.

Under the requirements of Fresh Start, we adjusted our assets and liabilities, other than deferred income taxes, to their estimated fair values as of December 5, 2003. As a result of marking our assets and liabilities to their estimated fair values, we determined that there was a negative reorganization value that was reallocated back to our tangible and intangible assets. Deferred taxes were determined in accordance with SFAS No. 109, *"Accounting for Income Taxes."* The net effect of all Fresh Start adjustments resulted in a gain of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations), which is reflected in the Predecessor Company's results for the period January 1, 2003 through December 5, 2003. The application of the Fresh Start provisions of SOP 90-7 created a new reporting entity having no retained earnings or accumulated deficit.

As part of the bankruptcy process we engaged an independent financial advisor to assist in the determination of our reorganized enterprise value. The fair value calculation was based on management's forecast of expected cash flows from our core assets. Management's forecast incorporated forward commodity market prices obtained from a third party consulting firm. A discounted cash flow calculation was used to develop the enterprise value of Reorganized NRG, determined in part by calculating the weighted average cost of capital of the Reorganized NRG. The Discounted Cash Flow, or DCF, valuation methodology equates the value of an asset or business to the present value of expected future economic benefits to be generated by that asset or business. The DCF methodology is a "forward looking" approach that discounts expected future economic benefits by a theoretical or observed discount rate. The independent financial advisor prepared a 30-year cash flow forecast using a discount rate of approximately 11%. The resulting reorganization enterprise value as included in the bankruptcy Disclosure Statement ranged from $5.5 billion to $5.7 billion. The independent financial advisor then subtracted our project-level debt and made several other adjustments to reflect the values of assets held for sale, excess cash and collateral requirements to estimate a range of Reorganized NRG equity value of between $2.2 billion and $2.6 billion.

In constructing our Fresh Start balance sheet upon our emergence from bankruptcy, we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Our reorganization value of approximately $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. The reorganization value represents the fair value of an entity before liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after restructuring. This value is consistent with the voting creditors and Court's approval of the Plan of Reorganization.

A separate plan of reorganization was filed for our Northeast Generating and South Central Generating entities that was confirmed by the bankruptcy court on November 25, 2003, and became effective on December 23, 2003, when the final conditions of the plan were completed. In connection with Fresh Start on December 5, 2003, we have accounted for these entities as if they had emerged from bankruptcy at the same time that we emerged, as we believe that we continued to maintain control over the Northeast Generating and South Central Generating facilities throughout the bankruptcy process.

Due to the adoption of Fresh Start upon our emergence from bankruptcy, the Reorganized NRG statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are therefore not comparable to the financial statements prior to the application of Fresh Start.

Nature of Operations

We are a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products in the United States and internationally. We have a diverse portfolio of electric generation facilities in terms of geography, fuel type, and dispatch levels, which help us mitigate risk. We seek to maximize operating income through the efficient procurement and management of fuel supplies and maintenance services, and the sale of energy, capacity and ancillary services into attractive spot, intermediate and long-term markets.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments (primarily commercial paper) with an original maturity of three months or less at the time of purchase.

Restricted Cash

Restricted cash consists primarily of funds held to satisfy the requirements of certain debt agreements and funds held within our projects that are restricted in their use.

Inventory

Inventory is valued at the lower of weighted average cost or market and consists principally of fuel oil, spare parts, coal, kerosene, emission allowance credits and raw materials used to generate steam.

Property, Plant and Equipment

Property, plant and equipment are stated at cost however impairment adjustments are recorded whenever events or changes in circumstances indicate carrying values may not be recoverable. On December 5, 2003, we recorded adjustments to the property, plant and equipment to reflect such items at fair value in accordance with Fresh Start reporting. A new cost basis was established with these adjustments. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred. Depreciation will be computed using the straight-line method over the following estimated useful lives:

Facilities and equipment	6-40 years
Office furnishings and equipment	3-10 years

The assets and related accumulated depreciation amounts are adjusted for asset retirements and disposals with the resulting gain or loss included in operations.

Asset Impairments

Long-lived assets that are held and used are reviewed for impairment whenever events or changes in circumstances indicate carrying values may not be recoverable. Such reviews are performed in accordance with SFAS No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Asset."* An impairment loss is recognized if the total future estimated undiscounted cash flows expected from an asset are less than its carrying value. An impairment charge is measured by the difference between an asset's carrying amount and fair value and included in operating costs and expenses in the statement of operations. Fair values are determined by a variety of valuation methods, including appraisals, sales prices of similar assets and present value techniques.

Investments accounted for by the equity method are reviewed for impairment in accordance with APB Opinion No. 18, *"The Equity Method of Accounting for Investments in Common Stock."* APB Opinion No. 18 requires that a loss in value of an investment that is other than a temporary decline should be recognized. We identify and measure losses in value of equity investments based upon a comparison of fair value to carrying value.

Discontinued Operations

Long-lived assets are classified as discontinued operations when all of the required criteria specified in SFAS No. 144 are met. These criteria include, among others, existence of a qualified plan to dispose of an asset, an assessment that completion of a sale within one year is probable and approval of the appropriate level of management and board of directors. Discontinued operations are reported at the lower of the asset's carrying amount or fair value less cost to sell.

Capitalized Interest

Interest incurred on funds borrowed to finance projects expected to require more than three months to complete is capitalized. Capitalization of interest is discontinued when the asset under construction is ready for its intended use or when a project is terminated or construction ceased. Capitalized interest was approximately $112.8 thousand, $1.5 thousand, $15.9 thousand and $64.8 million for the year ended December 31, 2004, the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, and for the year ended December 31, 2002, respectively.

Capitalized Project Costs

Development costs and capitalized project costs include third party professional services, permits, and other costs that are incurred incidental to a particular project. Such costs are expensed as incurred until an acquisition agreement or letter of intent is signed, and our Board of Directors has approved the project. Additional costs incurred after this point are capitalized. When a project begins operations, previously capitalized project costs are reclassified to equity investments in affiliates or property, plant and equipment and amortized on a straight-line basis over the lesser of the life of the project's related assets or revenue contract period. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

Debt Issuance Costs

Debt issuance costs are capitalized and amortized as interest expense on a basis which approximates the effective interest method over the terms of the related debt.

Intangible Assets

Intangible assets represent contractual rights held by us. Intangible assets are amortized over their economic useful life and reviewed for impairment on a periodic basis.

Income Taxes

The Reorganized NRG's income tax provision for the year ended December 31, 2004 and for the period December 6, 2003 through December 31, 2003 have been recorded on the basis that we and our U.S. subsidiaries will reconsolidate for federal income tax purposes as of December 6, 2003. The Reorganized NRG is no longer owned by Xcel Energy and thus, no longer included in the Xcel Energy affiliated group. The change in ownership allows us to file a consolidated federal income tax return with our U.S. subsidiaries starting on December 6, 2003.

The Predecessor Company's income tax provision has been recorded on the basis that Xcel Energy has not included us in its consolidated federal income tax return following Xcel Energy's acquisition of our public shares on June 3, 2002. Since we and our U.S. subsidiaries will not be included in the Xcel Energy's consolidated tax group, each of our U.S. subsidiaries that is classified as a corporation for U.S. income tax purposes must file a separate federal income tax return for the periods ended December 31, 2002 and December 5, 2003.

Deferred income taxes are recognized for the tax consequences in future years of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts at each year-end based on enacted tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. Income tax expense is the tax payable for the period and the change during the period in deferred tax assets and liabilities. A valuation allowance is recorded to reduce deferred tax assets to the amount more likely than not to be realized.

Revenue Recognition

We are primarily an electric generation company, operating a portfolio of majority-owned electric generating plants and certain plants in which our ownership interest is 50% or less which are accounted for under the equity method of accounting. In connection with our electric generation business, we also produce thermal energy for sale to customers, principally through steam and chilled water facilities. We also collect methane gas from landfill sites, which are used for the generation of electricity. In addition, we sell small amounts of natural gas and oil to third parties.

Both physical and financial transactions are entered into to optimize the financial performance of our generating facilities. Electric energy revenue is recognized upon transmission to the customer. In regions where bilateral markets exist and physical delivery of electricity is common from our plants, we record revenue on a gross basis. In certain markets, which are operated/controlled by an independent system operator and in which we have entered into a netting agreement with the ISO, which results in our receiving a netted invoice, we have recorded purchased energy as an offset against revenues received upon the sale of such energy. Revenues derived from the buying and selling of electricity not sourced from our facilities are reported net. Capacity and ancillary revenue is recognized when contractually earned. Disputed revenues are not recorded in the financial statements until disputes are resolved and collection is assured.

Revenue from long-term power sales contracts that provide for higher pricing in the early years of the contract are recognized in accordance with Emerging Issues Task Force Issue No. 91-6, *"Revenue Recognition of Long-Term Power Sales Contracts."* This results in revenue deferrals and recognition on a levelized basis over the term of the contract.

We provide contract operations and maintenance services to some of our non-consolidated affiliates. Revenue is recognized as contract services are performed.

We recognize other income for interest income on loans to our non-consolidated affiliates, as the interest is earned and realizable.

Derivative Financial Instruments

In January 2001, we adopted FAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities,"* or SFAS No. 133, as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149. SFAS No. 133, as amended, requires us to record all derivatives on the balance sheet at fair value. In some cases hedge accounting may apply. The criteria used to determine if hedge accounting treatment is appropriate are a) the designation of the hedge to an underlying exposure, b) whether or not the overall risk is being reduced and c) if there is correlation between the value of the derivative instrument and the underlying obligation. Formal documentation of the hedging relationship, the nature of the underlying risk, the risk management objective, and the means by which effectiveness will be assessed is created at the inception of the hedge. Changes in the fair value of non-hedge derivatives are immediately recognized in earnings. Changes in the fair value of derivatives accounted for as hedges are either recognized in earnings as an offset to the changes in the fair value of the related hedged assets, liabilities and firm commitments or for forecasted transactions, deferred and recorded as a component of accumulated other comprehensive income, or OCI, until the hedged transactions occur and are recognized in earnings. We primarily account for derivatives under SFAS No. 133, as amended, such as long-term power sales contracts, long-term gas purchase contracts and other energy related commodities and financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and to protect investments in fuel inventories. SFAS No. 133, as amended, also applies to interest rate swaps and foreign currency exchange rate contracts. The application of SFAS No. 133, as amended, results in increased volatility in earnings due to the recognition of unrealized gains and losses. In determining the fair value of these derivative/financial instruments we use estimates, various assumptions, judgment of management and when considered appropriate third party experts in determining the fair value of these derivatives.

Foreign Currency Translation and Transaction Gains and Losses

The local currencies are generally the functional currency of our foreign operations. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses and cash flows are translated at weighted-average rates of exchange for the period. The resulting currency translation adjustments are accumulated and reported as a separate component of stockholders' equity and are not included in the determination of the results of operations. Foreign currency transaction gains or losses are reported in results of operations. We recognized foreign currency transaction gains (losses) of $(1.7) million, $0.4 million, $(19.8) million and $(10.4) million for the year ended December 31, 2004, the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, and for the year ended December 31, 2002, respectively.

Concentrations of Credit Risk

Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of cash, accounts receivable, notes receivable and investments in debt securities. Cash accounts are generally held in federally insured banks. Accounts receivable, notes receivable and derivative instruments are concentrated within entities engaged in the energy industry. These industry concentrations may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. Receivables are generally not collateralized; however, we believe the credit risk posed by industry concentration is offset by the diversification and creditworthiness of our customer base.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, receivables, accounts payables, and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying amounts of long-term receivables approximate fair value, as the effective rates for these instruments are comparable to market rates at year-end, including current portions. The fair value of long-term debt is estimated based on quoted market prices for those instruments which are traded or on a present value method using current interest rates for similar instruments with equivalent credit quality.

Pensions

The determination of our obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. Our actuarial consultants use assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of pension obligation or expense recorded by us.

Stock Based Compensation

During the fourth quarter of 2003, in accordance with SFAS Statement No. 148, *"Accounting for Stock-Based Compensation — Transition and Disclosure"* we adopted SFAS No. 123 under the prospective transition method which requires the application of the recognition provisions to all employee awards granted, modified, or settled after the beginning of the fiscal year in which the recognition provisions are first applied. As a result, we applied the fair value recognition provisions of SFAS No. 123 as of January 1, 2003. As discussed in Note 21, we recognized compensation expense for the grants issued under the Long-Term Incentive Plan. The Black-Scholes option-pricing model is used for all non-qualified stock options.

Net Income Per Share

Basic net income per share is calculated based on the weighted average of common shares outstanding during the period. Net income per share, assuming dilution is computed by dividing net income available to common stockholders by the weighted average number of common and common equivalent shares outstanding. Our common equivalent shares are those that result from dilutive common stock options, issuance of restricted stock units, conversion of deferred stock units and conversion of preferred stock.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

In recording transactions and balances resulting from business operations, we use estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, actuarially determined benefit costs and the valuation of long-term energy commodities contracts, among others. In addition, estimates are used to test long-lived assets for impairment and to determine fair value of impaired assets. As better information becomes available (or actual amounts are determinable), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Reclassifications

Certain prior-year amounts have been reclassified for comparative purposes. These reclassifications had no effect on our net income or total stockholders' equity as previously reported.

Recent Accounting Developments

In November 2004, the Emerging Issue Task Force, or EITF, issued EITF No. 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* in Determining Whether to Report Discontinued Operations". EITF 03-13 clarifies the definition of cash flows of a component in which the seller engages in activities with the component after disposal, and significant continuing involvement in the operations of the component after the disposal transaction, and is effective for fiscal periods beginning after December 15, 2004. We are currently in the process of evaluating the potential impact that the adoption of this standard will have on our consolidated financial position and results of operations.

In November 2004, the FASB issued SFAS No. 151, *"Inventory Costs — an amendment of ARB No. 43, Chapter 4".* This statement amends the guidance in ARB No. 43, Chapter 4, "Inventory Pricing", and requires that idle facility expense, excessive spoilage, double freight, and rehandling costs be recognized as current-period charges regardless of whether they meet the criterion of "so abnormal" established by ARB No. 43. SFAS No. 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. We are currently in the process of evaluating the potential impact that the adoption of this statement will have on our consolidated financial position and results of operations.

In December 2004, the FASB issued SFAS No. 123R, *"Share-Based Payment"*, a revision to SFAS No. 123, *"Accounting for Stock-Based Compensation"*, which supersedes APB Opinion No. 25, *"Accounting for Stock Issued to Employees"* and its related implementation guidance. SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services, including obtaining employee services in share-based payment transactions. SFAS 123R applies to all awards granted after the required effective date and to awards modified, repurchased, or cancelled after that date. Adoption of the provisions of SFAS 123R is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. We have previously adopted SFAS No. 123, and we are currently in the process of evaluating the potential impact that the adoption of SFAS 123R will have on our consolidated financial position and results of operations.

In December 2004, the FASB issued two FASB Staff Positions, or FSPs, regarding the accounting implications of the American Jobs Creation Act of 2004 related to (1) the deduction for qualified domestic production activities (FSP FAS 109-1) and (2) the one-time tax benefit for the repatriation of foreign earnings (FSP FAS 109-2). In FSP FAS 109-1, *"Application of FASB Statement No. 109, "Accounting for Income Taxes," to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004"*, the Board decided that the deduction for qualified domestic production activities should be accounted for as a special deduction under FASB Statement No. 109, *"Accounting for Income Taxes"* and rejected an alternative view to treat it as a rate reduction. Accordingly, any benefit from the deduction should be reported in the period in which the deduction is claimed on the tax return. FSP FAS 109-2, *"Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004"*, addresses the appropriate point at which a company should reflect in its financial statements the effects of the one-time tax benefit on the repatriation of foreign earnings. Because of the proximity of the Act's enactment date to many companies' year-ends, its temporary nature, and the fact that numerous provisions of the Act are sufficiently complex and ambiguous, the Board decided that absent additional clarifying regulations, companies may not be in a position to assess the impact of the Act on their plans for repatriation or reinvestment of foreign earnings. Therefore, the Board provided companies with a practical exception to FAS 109's requirements by providing them additional time to determine the amount of earnings, if any, that they intend to repatriate under the Act's beneficial provisions. The Board confirmed, however, that upon deciding that some amount of earnings will be repatriated, a company must record in that period the associated tax liability, thereby making it clear that a company cannot avoid recognizing a tax liability when it has decided that some portion of its foreign earnings will be repatriated. We are currently in the process of evaluating the potential impact that the adoption of FSP FAS 109-1 and FSP FAS 109-2 will have on our consolidated financial position and results of operations.

Note 3 — Emergence from Bankruptcy and Fresh Start Reporting

In accordance with the requirements of SOP 90-7, we determined the reorganization value of NRG and subsidiaries emerging from bankruptcy to be approximately $9.1 billion. Reorganization value generally approximates fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring. Several methods are used to determine the reorganization value; however, generally it is determined by discounting future cash flows for the reconstituted business that will emerge from chapter 11 bankruptcy. Our approach was consistent in that our independent financial advisor's estimated reorganization enterprise value of our ongoing projects used a discounted cash flow approach.

We allocated the reorganization value of $9.1 billion to our assets in conformity with the procedures specified by SFAS No. 141. We used a third party to complete an independent appraisal of our tangible assets, equity investments and intangible assets and contracts. In completing the fair value allocation our assets were calculated to be greater than the reorganization value. As a result, we reallocated the negative reorganization value to our tangible and intangible assets in accordance with SFAS No. 141. In preparing our balance sheet we also recorded each liability existing at the plan confirmation date, other than deferred taxes, at the present value of amounts to be paid determined at appropriate current interest rates. Deferred taxes were reported in conformity with generally accepted accounting principles under SFAS No. 109. Our equity was recorded at approximately $2.4 billion representing a price per share of $24.04 for the issuance of 100,000,000 shares of common stock upon emergence from bankruptcy. We pushed down the effects of fresh start reporting to all of our subsidiaries.

In constructing our Fresh Start balance sheet using our reorganization value upon our emergence from bankruptcy, we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Accordingly, our reorganization value of $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. This value is consistent with the voting creditors and Court's approval of the Plan of Reorganization.

The determination of the enterprise value and the allocations to the underlying assets and liabilities were based on a number of estimates and assumptions, which are inherently subject to significant uncertainties and contingencies.

We recorded approximately $3.9 billion of net reorganization income (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) in the Predecessor Company's statement of operations for 2003, which includes the gain on the restructuring of debt and equity and the discharge of obligations subject to compromise for less than recorded amounts, as well as adjustments to the historical carrying values of our assets and liabilities to fair market value.

Due to the adoption of Fresh Start as of December 5, 2003, the Reorganized NRG statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of Fresh Start. The accompanying Consolidated Financial Statements have been prepared to distinguish between Reorganized NRG and the Predecessor Company.

APB No. 18, *"The Equity Method of Accounting for Investments in Common Stock"*, requires us to effectively push down the effects of Fresh Start reporting to our unconsolidated equity method investments and to recognize an adjustment to our share of the earnings or losses of an investee as if the investee was a consolidated subsidiary. As a result of pushing down the impact of Fresh Start to our West Coast Power affiliate we determined that a contract based intangible asset with a one year remaining life, consisting of the value of West Coast Power's California Department of Water Resources energy sales contract, must be established and recognized as a basis adjustment to our share of the future earnings generated by West Coast Power. This adjustment reduced our equity earnings in the amount of approximately $10.4 million per month during 2004 until the contract expired in December 2004.

Note 4 — Debtors' Statements

As stated above, we and certain of our subsidiaries filed voluntary petitions for reorganization under chapter 11 of the Bankruptcy Code during 2003. On December 5, 2003, we and five of our subsidiaries emerged from bankruptcy. As of the respective bankruptcy filing dates, the debtors' financial records were closed for the pre-petition period. As required by SOP 90-7 *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code"*, below are the condensed combined financial statements of our remaining debtors since the date of the bankruptcy filings, or the Debtors' Statements.

The Debtors' Statements consist of the following wholly-owned consolidated entities which remained in bankruptcy as of December 6, 2003: Arthur Kill Power LLC, Astoria Gas Turbine Power LLC, Berrians I Gas Turbine Power, LLC, Big Cajun II Unit 4 LLC, Connecticut Jet Power LLC, Devon Power LLC, Dunkirk Power LLC, Huntley Power LLC, Louisiana Generating LLC, LSP-Nelson Energy LLC, Middletown Power LLC, Montville Power LLC, Northeast Generation Holding LLC, Norwalk Power LLC, NRG Central US LLC, NRG Eastern LLC, NRG McClain LLC, NRG Nelson Energy LLC, NRG New

Roads Holdings LLC, NRG Northeast Generating LLC, NRG South Central Generating LLC, Oswego Harbor Power LLC, Somerset Power LLC, and South Central Generation Holding LLC. As of December 31, 2004, one entity remains in bankruptcy to effect its liquidation.

Debtors' Condensed Combined Statement of Operations

	For the Period May 15, 2003 - December 5, 2003
	(In thousands)
Operating revenue	$ 731,413
Operating costs and expenses	(620,199)
Fresh start reporting adjustments — asset write-downs, net	(1,244,016)
Reorganization items	(27,158)
Restructuring and impairment charges	(23,359)
Operating loss	(1,183,319)
Other expense	(160,246)
Net loss	$(1,343,565)

Debtors' Condensed Combined Statement of Cash Flows

	For the Period May 15, 2003 - December 5, 2003
	(In thousands)
Net cash provided by operating activities	$ 65,951
Net cash used by investing activities	(72,667)
Net cash used by financing activities	—
Net increase in cash and cash equivalents	(6,716)
Cash and cash equivalents at beginning of period	23,137
Cash and cash equivalents at end of period	$ 16,421

Note 5 — Financial Instruments

The estimated fair values of our recorded financial instruments are as follows:

	Reorganized NRG			
	December 31, 2004		December 31, 2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Cash and cash equivalents	$1,110,045	$1,110,045	$ 551,223	$ 551,223
Restricted cash	112,824	112,824	116,067	116,067
Accounts receivable — trade	272,101	272,101	201,921	201,921
Notes receivable, including current portion	889,969	889,969	886,937	886,937
Decommissioning fund investments	4,954	4,954	4,809	4,809
Accounts payable — trade	166,131	166,131	158,646	158,646
Accounts payable — affiliates	5,591	5,591	3,092	3,092
Long-term debt, including current portion	3,766,118	3,906,623	4,129,011	4,186,136

For cash and cash equivalents, restricted cash, accounts receivable and accounts payable, the carrying amount approximates fair value because of the short-term maturity of those instruments. The fair value of notes receivable is based on expected future cash flows discounted at market interest rates. Decommissioning fund investments are comprised of various U.S. debt securities carried at amortized cost, which approximates their fair value. The fair value of long-term debt is estimated based on quoted market prices for those instruments which are traded or on a present value method using current interest rates for similar instruments with equivalent credit quality.

Note 6 — Discontinued Operations

We have classified certain business operations, and gains/(losses) recognized on sale, as discontinued operations for projects that were sold or have met the required criteria for such classification. The financial results for all of these businesses have been accounted for as discontinued operations. Accordingly, current period operating results and prior periods have been restated to report the operations as discontinued.

SFAS No. 144 requires that discontinued operations be valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions our management considered cash flow analyses, bids and offers related to those assets and businesses. This amount is included in income/(loss) on discontinued operations, net of income taxes in the accompanying Statement of Operations. In accordance with the provisions of SFAS No. 144, assets held for sale will not be depreciated commencing with their classification as such.

The assets and liabilities of the discontinued operations are reported in the December 31, 2004 and 2003 balance sheets as discontinued operations. The major classes of assets and liabilities are presented by geographic area in the following table.

	Reorganized NRG				
	December 31, 2004	December 31, 2003			
	Wholesale Power Generation	Wholesale Power Generation	All Other		
			Wholesale Power Generation		
	Other North America	Other North America	Other International	Alternative Energy	Total
	Consists of McClain	Consists of PERC, McClain and LSP Energy	Consists of Cobee and Hsin Yu	Consists of four NEO projects	
		(In thousands)			
Cash and cash equivalents	$1,684	$ 4,292	$ 8,264	$ —	$ 12,556
Restricted cash	1,326	60,292	—	—	60,292
Receivables, net	—	12,676	11,259	—	23,935
Inventory	—	8,722	3,538	—	12,260
Other current assets	—	3,731	6,787	40	10,558
Current assets — discontinued operations	$3,010	$ 89,713	$ 29,848	$ 40	$119,601
Property, plant and equipment, net	$ —	$487,753	$ 75,250	$ —	$563,003
Deferred income taxes	—	—	31,469	—	31,469
Other non-current assets	—	14,765	9,731	4,205	28,701
Non-current assets — discontinued operations	$ —	$502,518	$116,450	$4,205	$623,173
Current portion of long-term debt	$ —	$ 6,206	$ 49,744	$ —	$ 55,950
Accounts payable — trade	732	3,057	23,037	3,998	30,092
Accrued interest	630	13,182	757	—	13,939
Other current liabilities	—	8,248	5,946	22	14,216
Current liabilities — discontinued operations	$1,362	$ 30,693	$ 79,484	$4,020	$114,197
Long-term debt	$ —	$313,738	$ 19,779	$ —	$333,517
Minority interest	—	31,879	406	—	32,285
Other non-current liabilities	1,081	184,972	8,110	—	193,082
Non-current liabilities — discontinued operations	$1,081	$530,589	$ 28,295	$ —	$558,884

The following table summarizes our discontinued operations for all periods presented in our consolidated financial statements:

Project	Segment	Initial Discontinued Operations Treatment Date	Disposal Date
Bulo Bulo	Other International	Second Quarter 2002	Fourth Quarter 2002
Crockett Cogeneration	Other North America	Third Quarter 2002	Fourth Quarter 2002
Csepel and Entrade	Other International	Third Quarter 2002	Fourth Quarter 2002
Killingholme	Other International	Fourth Quarter 2002	First Quarter 2003
NLGI	Alternative Energy	Second Quarter 2003	Second Quarter 2003
TERI	Non-Generation	Third Quarter 2003	Third Quarter 2003
McClain	Other North America	Third Quarter 2003	Third Quarter 2004
NEO Corporation (NEO Fort Smith LLC, NEO Woodville LLC, NEO Phoenix LLC)	Alternative Energy	Fourth Quarter 2003	Fourth Quarter 2003
Cahua and Energia Pacasmayo	Other International	Fourth Quarter 2003	Fourth Quarter 2003
PERC	Other North America	First Quarter 2004	Second Quarter 2004
Cobee	Other International	First Quarter 2004	Second Quarter 2004
Hsin Yu	Other International	Second Quarter 2004	Second Quarter 2004
LSP Energy (Batesville)	Other North America	Second Quarter 2004	Third Quarter 2004
NEO Corporation (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC)	Alternative Energy	Third Quarter 2004	Third Quarter 2004

Summarized results of operations were as follows:

Description	Reorganized NRG: Year Ended December 31, 2004	Reorganized NRG: For the Period December 6 - December 31, 2003	Predecessor Company: For the Period January 1 - December 5, 2003	Predecessor Company: Year Ended December 31, 2002
	(In thousands)			
Operating revenues	$108,428	$19,195	$ 263,404	$ 982,263
Operating costs and other expenses	106,389	19,565	619,714	1,670,709
Pre-tax income/(loss) from operations of discontinued components	2,039	(370)	(356,310)	(688,446)
Income tax expense/(benefit)	986	10	(21,868)	(6,810)
Income/(loss) from operations of discontinued components	1,053	(380)	(334,442)	(681,636)
Disposal of discontinued components — pre-tax gain (net)	30,273	—	151,809	2,814
Income tax expense/(benefit)	7,854	—	—	(2,992)
Disposal of discontinued components — gain (net)	22,419	—	151,809	5,806
Income/(loss) on discontinued operations, net of income taxes	$ 23,472	$ (380)	$(182,633)	$ (675,830)

The components of income tax expense/(benefit) attributable to discontinued operations were as follows:

Discontinued Operations:	Reorganized NRG: Year Ended December 31, 2004	Reorganized NRG: For the Period December 6 - December 31, 2003	Predecessor Company: For the Period January 1 - December 5, 2003	Predecessor Company: Year Ended December 31, 2002
	(In thousands)			
Current				
U.S.	$ —	$—	$ (6)	$ 935
Foreign	918	10	(831)	(5,126)
	918	10	(837)	(4,191)
Deferred				
U.S.	20	—	—	(1,947)
Foreign	48	—	(21,031)	(672)
	68	—	(21,031)	(2,619)
Income tax expense/(benefit) on discontinued operations	986	10	(21,868)	(6,810)
U.S. tax expense/(benefit) on disposal of discontinued components — gain (net)	7,854	—	—	(2,992)
Total income tax expense/(benefit)	$8,840	$10	$(21,868)	$(9,802)

Operating costs and other expenses for 2004 shown in the table above include asset impairment charges of approximately $0.2 million. Operating costs and other expenses for 2003 include asset impairment charges of approximately $124.3 million, comprised of approximately $100.7 million for McClain and $23.6 million for NLGI. Operating costs and other expenses for 2002 included asset impairment charges of approximately $502.0 million of which approximately $477.9 million is attributable to the Killingholme project, $121.9 million for the Hsin Yu project, $64.7 million for the Batesville turbine project, $12.4 million for the NEO Landfill Gas, Inc. project and $11.7 million for the TERI project offset by other credits of $186.6 million. The pre-tax gain or loss on disposals of discontinued components consist of the following:

		Reorganized NRG		Predecessor Company	
Project	Segment	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
		(In millions)			
McClain	Other North America	$(3.0)	$—	$ —	$ —
PERC	Other North America	3.2	—	—	—
Cobee	Other International	2.8	—	—	—
LSP Energy — Batesville	Other North America	11.0	—	—	—
Hsin Yu	Other International	10.3	—	—	—
NEO Nashville, Hackensack, Prima Deshecha, Tajiguas	Alternative Energy	6.0	—	—	—
NEO Fort Smith, Woodville, Phoenix	Alternative Energy	—	—	—	—
Killingholme	Other International	—	—	191.2	—
TERI	Non-Generation	—	—	1.0	—
Cahua and Energia Pacasmayo	Other International	—	—	(36.9)	—
Crockett Cogeneration	Other North America	—	—	—	(11.5)
Bulo Bulo	Other International	—	—	—	(10.6)
Csepel and Entrade	Other International	—	—	—	24.0
Others		—	—	(3.5)	0.9
Total gain on disposal of discontinued components — pre-tax		$30.3	$—	$151.8	$ 2.8

McClain — We reviewed the recoverability of our McClain assets pursuant to SFAS No. 144 and recorded a charge of $100.7 million in the second quarter of 2003. On August 14, 2003, NRG's Board of Directors approved a plan to sell its 77% interest in McClain Generating Station, a 520-MW combined-cycle, natural gas-fired facility located in New Castle, Oklahoma. On July 9, 2004, NRG McClain completed the sale of its 77% interest in the McClain Generating Station to Oklahoma Gas & Electric Company. The Oklahoma Municipal Power Authority will continue to own the remaining 23% interest in the facility. The proceeds of $160.2 million from the sale were used to repay outstanding project debt under the secured term loan and working capital facility. A loss of $3.0 million was recognized as of June 30, 2004 based upon the final terms of the sale.

Penobscot Energy Recovery Company (PERC) — During the first quarter of 2004, we received board authorization to proceed with the sale of our interest in PERC to SET PERC Investment LLC which reached financial closing in April 2004. Upon completion of the transaction, we received net proceeds of $18.4 million, resulting in a gain of $3.2 million.

Cobee — During the first quarter of 2004, we entered into an agreement for the sale of our interest in our Cobee project to Globeleq Holdings Limited, which reached financial closing in April 2004. Upon completion of the transaction, we received net proceeds of approximately $50.0 million, resulting in a gain of $2.8 million.

LSP Energy — Batesville — On August 24, 2004, we completed the sale of our 100 percent interest in an 837-megawatt generating plant in Batesville, Mississippi to CEP Batesville Acquisition, LLC. CEP Batesville Acquisition, LLC assumed approximately $300 million of outstanding project debt. The transaction resulted in the elimination of $289.3 million in consolidated debt from NRG Energy's balance sheet. In exchange for the sale, we received cash proceeds of $27.6 million. We recorded a gain of $11.0 million in 2004.

Hsin Yu — During the second quarter of 2004, we entered into an agreement for the sale of our interest in our Hsin Yu project to a minority interest shareholder, Asia Pacific Energy Development Company Ltd., which reached financial closing in May 2004. Upon completion of the transaction, we received net proceeds of $0.2 million, resulting in a gain of approximately $10.3 million, resulting from our negative equity in the project. In addition, although we have no continuing involvement in the project, we retained the prospect of receiving an additional $1.0 million in additional proceeds upon final closing of Phase II of the project.

NEO Corporation — In August of 1995, we entered into a Marketing, Development and Joint Proposing Agreement, or the Marketing Agreement, with Cambrian Energy Development LLC, or Cambrian. Various claims had arisen in connection with this Marketing Agreement. In November 2003, we entered into a settlement agreement with Cambrian where we agreed to transfer our 100% interest in three gasco projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville). During the third quarter of 2004, we completed the sale of four wholly-owned entities — NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC, as well as the sale of several NEO investments — Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC to Algonquin Power of Canada (see Note 7). Upon completion of the transaction, we received cash proceeds of $5.8 million, resulting in a $6.0 million gain associated with the four wholly-owned entities sold and received cash proceeds of $6.1 million resulting in a loss of approximately $3.8 million attributable to the equity investments sold. The sale of these equity investments do not qualify for reporting purposes as discontinued operations.

Killingholme — During third quarter 2002, we recorded an impairment charge of $477.9 million. In January 2003, we completed the sale of our interest in the Killingholme project to our lenders for a nominal value and forgiveness of outstanding debt with a carrying value of approximately $360.1 million at December 31, 2002. The sale of our interest in the Killingholme project and the release of debt obligations resulted in a gain on sale in the first quarter of 2003 of approximately $191.2 million. The gain results from the write-down of the project's assets in the third quarter of 2002 below the carrying value of the related debt.

NLGI — During 2002, we recorded an impairment charge of $12.4 million related to subsidiaries of NLGI, an indirect wholly-owned subsidiary of NRG Energy. The charge was related largely to asset impairments based on a revised project outlook. During the quarter ended March 31, 2003, we recorded impairment charges of $23.6 million related to subsidiaries of NLGI and a charge of $14.5 million to write off our 50% investment in Minnesota Methane, LLC. (See Note 7). Through April 30, 2003, NRG Energy and NLGI failed to make certain payments causing a default under NLGI's term loan agreements. In May 2003, the project lenders to the wholly-owned subsidiaries of NLGI and Minnesota Methane LLC foreclosed on our membership interest in the NLGI subsidiaries and our equity interest in Minnesota Methane LLC. There was no material gain or loss recognized as a result of the foreclosure.

TERI — During 2002, we recorded an impairment charge of $11.7 million based on a revised project outlook. In September 2003, we completed the sale of TERI, a biomass waste-fuel power plant located in Florida and a wood processing facility located in Georgia, to DG Telogia Power, LLC. The sale resulted in net proceeds of approximately $1.0 million. We entered into an agreement to sell the wood processing facility on behalf of DG Telogia Power, LLC. This sale was completed during fourth quarter 2003 and we received cash consideration of approximately $1.0 million, resulting in a net gain on sale of approximately $1.0 million.

Cahua and Energia Pacasmayo — In November 2003, we completed the sale of Cahua and Energia Pacasmayo resulting in net cash proceeds of approximately $16.2 million and a loss of $36.9 million. In addition, we received an additional consideration adjustment of approximately $0.7 million during 2004.

Crockett Cogeneration Project — In September 2002, we announced that we had reached an agreement to sell our 57.7% interest in the Crockett Cogeneration Project, a 240 MW natural gas fueled cogeneration plant near San Francisco, California, to Energy Investment Fund Group, an existing LP, and a unit of GE Capital. In November 2002, the sale closed and we realized net cash proceeds of approximately $52.1 million (net of cash transferred of $0.2 million) and a loss on disposal of approximately $11.5 million.

Bulo Bulo — In June 2002, we began negotiations to sell our 60% interest in Compania Electrica Central Bulo Bulo S.A. (Bulo Bulo), a Bolivian corporation. The transaction reached financial close in the fourth quarter of 2002 resulting in cash proceeds of $10.9 million (net of cash transferred of $8.6 million) and a loss of $10.6 million.

Csepel and Entrade — In September 2002, we announced that we had reached agreements to sell our Csepel power generating facilities (located in Budapest, Hungary) and our interest in Entrade (an electricity trading business headquartered in Prague) to Atel, an independent energy group headquartered in Switzerland. The sales of Csepel and Entrade closed before year-end 2002 and resulted in cash proceeds of $92.6 million (net of cash transferred of $44.1 million) and a gain of approximately $24.0 million.

Note 7 — Write Downs and Losses on Sales of Equity Method Investments

Investments accounted for by the equity method are reviewed for impairment in accordance with APB Opinion No. 18. APB Opinion No. 18 requires that a loss in value of an investment that is other than a temporary decline should be recognized. Gains or losses are recognized on completion of the sale. Write downs and losses on sales of equity method investments recorded in other income/expense in the consolidated statement of operations includes the following:

	Segment	Reorganized NRG Year Ended December 31, 2004	Reorganized NRG For the Period December 6 - December 31, 2003	Predecessor Company For the Period January 1 - December 5, 2003	Predecessor Company Year Ended December 31, 2002
		(In thousands)			
Commonwealth Atlantic Limited Partnership	Other North America	$ 4,614	$—	$ —	$ —
James River Power LLC	Other North America	7,293	—	—	—
NEO Corporation	Alternative Energy	3,830	—	—	—
Calpine Cogeneration	Other North America	(735)	—	—	—
NLGI — Minnesota Methane	Alternative Energy	—	—	12,257	12,292
NLGI — MM Biogas	Alternative Energy	—	—	2,613	3,251
Kondapalli	Other International	—	—	(519)	12,751
ECKG	Other International	—	—	(2,871)	—
Loy Yang	Australia	1,268	—	146,354	111,383
Mustang	Other North America	—	—	(12,124)	—
Energy Development Limited (EDL)	Australia	—	—	—	14,220
Sabine River Works	Other North America	—	—	—	48,375
Kingston	Other International	—	—	—	(9,876)
Mt. Poso	West Coast	—	—	—	1,049
Powersmith	Other North America	—	—	—	3,441
Collinsville Power Station	Australia	—	—	—	3,586
Other		—	—	1,414	—
Total write downs and losses on sales of equity method investments		$16,270	$—	$147,124	$200,472

Commonwealth Atlantic Limited Partnership (CALP) — In June 2004, we executed an agreement to sell our 50% interest in CALP. During the third quarter of 2004, we recorded an impairment charge of approximately $3.7 million to write down the value of our investment in CALP to its fair value. The sale closed in November 2004 resulting in net cash proceeds of $14.9 million. Total impairment charges as a result of the sale were $4.6 million.

James River Power LLC — In September 2004, we executed an agreement with Colonial Power Company LLC to sell all of our outstanding shares of stock in Capistrano Cogeneration Company, a wholly-owned subsidiary of NRG Energy which owns a 50% interest in James River Cogeneration Company. During the third quarter of 2004, we recorded an impairment charge of approximately $6.0 million to write down the value of our investment in James River to its fair value. During the fourth quarter of 2004, the sales agreement was terminated. We continue to impair any additional equity earnings based on its fair value. Total impairment charges for 2004 were $7.3 million.

NEO Corporation — On September 30, 2004, we completed the sale of several NEO investments — Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC to Algonquin Power of Canada. The sale also included four wholly-owned NEO subsidiaries (see Note 6). We received cash proceeds of $6.1 million. The sale resulted in a loss of approximately $3.8 million attributable to the equity investment entities sold.

Calpine Cogeneration — In January 2004, we executed an agreement to sell our 20% interest in Calpine Cogeneration Corporation to Calpine Power Company. The transaction closed in March 2004 and resulted in net cash proceeds of $2.5 million and a net gain of $0.2 million. During the second quarter of 2004, we received additional consideration on the sale of $0.5 million, resulting in an adjusted net gain of $0.7 million.

NLGI — Minnesota Methane — We recorded an impairment charge of $12.3 million during 2002 to write-down our 50% investment in Minnesota Methane. We recorded an additional impairment charge of $14.5 million during the first quarter of 2003. These charges were related to a revised project outlook and management's belief that the decline in fair value was other than temporary. In May 2003, the project lenders to the wholly-owned subsidiaries of NEO Landfill Gas, Inc. and Minnesota Methane LLC foreclosed on our membership interest in the NEO Landfill Gas, Inc. subsidiaries and our equity interest in Minnesota Methane LLC. Upon completion of the foreclosure, we recorded a gain of $2.2 million resulting in a net impairment charge of $12.3 million. The gain upon completion of the foreclosure resulted from the release of certain obligations upon completion of the foreclosure.

NLGI — MM Biogas — We recorded an impairment charge of $3.2 million during 2002 to write-down our 50% investment in MM Biogas. This charge was related to a revised project outlook and management's belief that the decline in fair value was other than temporary. In November 2003, we entered into a sales agreement with Cambrian Energy Development to sell our 50% interest in MM Biogas. We recorded an additional impairment charge of $2.6 million during the fourth quarter of 2003 due to developments related to the sale that indicated an impairment of our book value that was considered to be other than temporary.

Kondapalli — In the fourth quarter of 2002, we wrote down our investment in Kondapalli by $12.7 million due to recent estimates of sales value, which indicated an impairment of our book value that was considered to be other than temporary. On January 30, 2003, we signed a sale agreement with the Genting Group of Malaysia, or Genting, to sell our 30% interest in Lanco Kondapalli Power Pvt Ltd, or Kondapalli, and a 74% interest in Eastern Generation Services (India) Pvt Ltd (the O&M company). Kondapalli is based in Hyderabad, Andhra Pradesh, India, and is the owner of a 368 MW natural gas fired combined cycle gas turbine. In the first quarter of 2003, we wrote down our investment in Kondapalli by $1.3 million based on the final sale agreement. The sale closed on May 30, 2003 resulting in net cash proceeds of approximately $24 million and a gain of approximately $1.8 million resulting in a net gain of $0.5 million. The gain resulted from incurring lower selling costs than estimated as part of the first quarter impairment.

ECKG — In September 2002, we announced that we had reached agreement to sell our 44.5% interest in the ECKG power station in connection with our Csepel power generating facilities, and our interest in Entrade, an electricity trading business, to Atel, an independent energy group headquartered in Switzerland. The transaction closed in January 2003 and resulted in cash proceeds of $65.3 million and a net loss of less than $1.0 million. In accordance with the purchase agreement, we were to receive additional consideration if Atel purchased shares held by our partner. During the second quarter of 2003, we received approximately $3.7 million of additional consideration resulting in a net gain of $2.9 million.

Loy Yang — Based on a third party market valuation and bids received in response to marketing Loy Yang for possible sale, we recorded a write down of our investment of approximately $111.4 million during 2002. This write-down reflected management's belief that the decline in fair value of the investment was other than temporary. In May 2003, we entered into negotiations that culminated in the completion of a Share Purchase Agreement to sell 100% of the Loy Yang project. Consequently, we recorded an additional impairment charge of approximately $146.4 million during 2003. In April 2004 we completed the sale of Loy Yang which resulted in net cash proceeds of $26.7 million and a loss of $1.3 million.

Mustang Station — On July 7, 2003, we completed the sale of our 25% interest in Mustang Station, a gas-fired combined cycle power generating plant located in Denver City, Texas, to EIF Mustang Holdings I, LLC. The sale resulted in net cash proceeds of approximately $13.3 million and a net gain of approximately $12.1 million.

Energy Development Limited — On July 25, 2002, we announced that we completed the sale of our ownership interests in an Australian energy company, Energy Development Limited, or EDL. EDL is a listed Australian energy company engaged in the development and management of an international portfolio of projects with a particular focus on renewable and waste fuels. In October 2002, we received proceeds of AUD 78.5 million, or approximately $43.9 million (USD), in exchange for our ownership interest in EDL with the closing of the transaction. During the third quarter of 2002, we recorded an impairment charge of approximately $14.2 million to write down the carrying value of our equity investment due to the pending sale.

Sabine River — In September 2002, we agreed to transfer our indirect 50% interest in SRW Cogeneration LP, or SRW, to our partner in SRW, Conoco, Inc. in consideration for Conoco's agreement to terminate or assume all of our obligations, in relation to SRW. SRW owns a cogeneration facility in Orange County, Texas. We recorded a charge of approximately $48.4 million during the quarter ended September 30, 2002 to write down the carrying value of our investment due to the pending sale. The transaction closed on November 5, 2002.

Kingston — In December 2002, we completed the sale of our 25% interest in Kingston Cogeneration LP, based near Toronto, Canada to Northland Power Income Fund. We received net proceeds of $15.0 million resulting in a gain on sale of approximately $9.9 million.

Mt. Poso — In September 2002, we agreed to sell our 39.5% indirect partnership interest in the Mt. Poso Cogeneration Company, a California limited partnership, or Mt. Poso, for approximately $10 million to Red Hawk Energy, LLC. Mt. Poso owns a 49.5 MW coal-fired cogeneration power plant and thermally enhanced oil recovery facility located 20 miles north of Bakersfield, California. The sale closed in November 2002 resulting in a loss of approximately $1.0 million.

Powersmith — During the fourth quarter of 2002, we wrote down our investment in Powersmith in the amount of approximately $3.4 million due to recent developments, which indicated impairment of our book value that was considered to be other than temporary.

Collinsville Power Station — Based on third party market valuation and bids received in response to marketing the investment for possible sale, we recorded a write down of our investment of approximately $4.1 million during the second quarter of 2002. In August 2002, we announced that we had completed the sale of our 50% interest in the 192 MW Collinsville Power Station in Australia, to our partner, a subsidiary of Transfield Services Limited for AUD 8.6 million, or approximately $4.8 million (USD). Our ultimate loss on the sale of Collinsville Power Station was approximately $3.6 million.

Note 8 — Other Charges (Credits)

Other charges and credits included in operating expenses in the Consolidated Statement of Operations include the following:

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
Corporate relocation charges	$ 16,167	$ —	$ —	$ —
Reorganization items	(13,390)	2,461	197,825	—
Impairment charges	44,661	—	228,896	2,451,745
Restructuring charges	—	—	8,679	111,315
Fresh Start adjustments	—	—	(4,118,636)	—
Legal settlement	—	—	462,631	—
Total	$ 47,438	$2,461	$(3,220,605)	$2,563,060

Corporate Relocation Charges

On March 16, 2004, we announced plans to implement a new regional business strategy and structure. The new structure called for a reorganized leadership team and a corporate headquarters relocation to Princeton, New Jersey. The corporate headquarters staff were streamlined as part of the relocation, as functions were either reduced or shifted to the regions. As of December 31, 2004, the transition of our corporate headquarters is substantially complete.

For the year ended December 31, 2004, we recorded $16.2 million for charges related to our corporate relocation activities, primarily for employee severance and termination benefits and employee related transition costs. These charges are classified separately in our statement of operations, in accordance with SFAS No. 146, *"Accounting for Costs Associated with Exit or Disposal Activities"*. We expect to incur an additional $7.7 million of SFAS No. 146-classified expenses in connection with corporate relocation charges for a total of $23.9 million. Of this total, relocating, recruiting and other employee-related transition costs are expected to be approximately $11.9 million and have been and will continue to be expensed as incurred. These costs and cash payments are expected to be incurred through the second quarter of 2005. Severance and termination benefits of $7.2 million are expected to be incurred through the second quarter of 2005 with cash payments being made through the fourth quarter of 2005. Building lease termination costs are expected to be $4.8 million. These costs are expected to be incurred through the first quarter of 2005 with cash payments being made through the fourth quarter of 2006.

A summary of the significant components of the restructuring liability is as follows:

	Balance at December 31, 2003	Relocation Related Charges	Cash Payments	Balance at December 31, 2004
	(In thousands)			
Employee related transition costs	$—	$ 8,595	$(10,020)	$(1,425)
Severance and termination benefits	—	6,505	(2,316)	4,189
Lease termination costs	—	1,067	(271)	796
Total	$—	$16,167	$(12,607)	$ 3,560

As of December 31, 2004, the net restructuring liability was $3.6 million, the majority of which is included in other current liabilities on the consolidated balance sheet. Charges related to the employee related transition costs, severance and termination benefits and lease termination costs are recorded at our corporate level within our All Other — Other segment, in the corporate relocation charges line on the consolidated statement of operations.

Reorganization Items

For the year ended December 31, 2004, we recorded a net credit of $13.4 million related primarily to the settlement of obligations recorded under Fresh Start. For the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, we incurred $2.5 million and $197.8 million, respectively, in reorganization costs. All reorganization costs have been incurred since we filed for bankruptcy in May 2003. The following table provides the detail of the types of costs incurred. There were no reorganization items in 2002.

	Reorganized NRG		Predecessor Company
	Year Ended December 31, 2004	For the period December 6 - December 31, 2003	For the period January 1 - December 5, 2003
		(In thousands)	
Reorganization items			
Professional fees	$ 7,383	$2,461	$ 82,186
Deferred financing costs	—	—	55,374
Pre-payment settlement	—	—	19,609
Interest earned on accumulated cash	—	—	(1,059)
Contingent equity obligation	—	—	41,715
Settlement of obligations and other gains	(20,773)	—	—
Total reorganization items	$(13,390)	$2,461	$197,825

Impairment Charges

We review the recoverability of our long-lived assets in accordance with the guidelines of SFAS No. 144. As a result of this review, we recorded impairment charges of $44.7 million, $228.9 million and $2.5 billion, for the year ended December 31, 2004, the period January 1, 2003 through December 5, 2003 and for the year ended December 31, 2002, respectively, as shown in the table below.

To determine whether an asset was impaired, we compared asset-carrying values to total future estimated undiscounted cash flows. If an asset was determined to be impaired based on the cash flow testing performed, an impairment loss was recorded to write down the asset to its fair value.

Impairment charges (credits) included the following asset impairments (realized gains) for the year ended December 31, 2004, the period January 1, 2003 to December 5, 2003 and for the year ended December 31, 2002. There were no impairment charges for the period December 6, 2003 to December 31, 2003.

Project Name	Project Status	Reorganized NRG Year Ended December 31, 2004	Predecessor Company For the Period January 1 - December 5, 2003	Predecessor Company Year Ended December 31, 2002	Fair Value Basis
			(In thousands)		
Louisiana Generating LLC	Office building and land being marketed	$ 493	$ —	$ —	Estimated market price
New Roads Holding LLC (turbine)	Non-operating asset — abandoned	2,416	—	—	Projected cash flows
Devon Power LLC	Operating at a loss in 2003	247	64,198	—	Projected cash flows
Middletown Power LLC	Operating at a loss	—	157,323	—	Projected cash flows
Arthur Kill Power, LLC	Terminated construction project	—	9,049	—	Projected cash flows
Langage (UK)	Terminated	—	(3,091)	42,333	Estimated market price/Realized gain
Turbines	Sold	—	(21,910)	—	Realized gain
Berrians Project	Terminated	—	14,310	—	Realized loss
TermoRio	Terminated	—	6,400	—	Realized loss
Nelson	Sold	—	—	467,523	Similar asset prices
Pike	Terminated	—	—	402,355	Similar asset prices
Bourbonnais	Terminated	—	—	264,640	Similar asset prices
Meriden (turbine only)	Pending sale	15,000	—	144,431	Similar asset prices
Brazos Valley	Foreclosure completed in 2003	—	—	102,900	Projected cash flows
Kendall	Sold	26,505	—	55,300	Realized loss
Turbines & equipment	Equipment being marketed	—	—	701,573	Similar asset prices
Audrain	Operating at a loss	—	—	66,022	Projected cash flows
Somerset	Operating at a loss	—	—	49,289	Projected cash flows
Bayou Cove	Operating at a loss	—	—	126,528	Projected cash flows
Other		—	2,617	28,851	
Total impairment charges		$44,661	$228,896	$2,451,745	

Louisiana Generating LLC — In January 2004, we closed the South Central regional office in Baton Rouge, Louisiana and offered it for sale. During the fourth quarter of 2004, we recorded a charge of $0.5 million related to the impairment to net realizable value based on two offers received. Louisiana Generating is included in our South Central segment.

New Roads Holding LLC — During the second quarter of 2004, we reviewed the recoverability of our New Roads assets pursuant to SFAS No. 144 and recorded a charge of approximately $1.7 million related to the impairment to realizable value of a turbine acquired in March 2000 from Cajun Electric. During the third quarter of 2004, we recorded an additional charge of $0.7 million to write the turbine's value down to its scrap value. New Roads Holding is included in our South Central segment.

Connecticut Facilities (Devon Power LLC and Middletown Power LLC) — As a result of regulatory developments and changing circumstances in the second quarter of 2003, we updated the facilities' cash flow models to incorporate changes to reflect the impact of the April 25, 2003 FERC's orders on regional and locational pricing, and to update the estimated impact of future locational capacity or deliverability requirements. Based on these revised cash flow models, management determined that the new estimates of pricing and cost recovery levels were not projected to return sufficient revenue to cover the fixed costs at Devon Power LLC and Middletown Power LLC. As a consequence, during the second quarter of 2003 we recorded $64.2 million and $157.3 million as impairment charges for Devon Power LLC and Middletown

Power LLC, respectively. In the third quarter of 2004, ISO-NE informed the Company that it would not extend the RMR contract for Devon units 7 and 8. As a result, both units have been placed on deactivated reserve and we recorded an additional impairment charge of $0.2 million for Devon Power LLC. Devon Power and Middletown Power are included in our Northeast segment.

Arthur Kill Power, LLC — During the third quarter of 2003, we cancelled our plans to re-establish fuel oil capacity at our Arthur Kill plant. This resulted in a charge of approximately $9.0 million to write-off assets under development. Arthur Kill Power is included in our Northeast segment.

Langage (UK) — During the third quarter of 2002, we reviewed the recoverability of our Langage assets pursuant to SFAS No. 144 and recorded a charge of $42.3 million. In August 2003 we closed on the sale of Langage to Carlton Power Limited resulting in net cash proceeds of approximately $1.5 million, of which $1.0 million was received in 2003 and $0.5 million was received during the first quarter of 2004, and a net gain of approximately $3.1 million. Langage is included in our All Other segment under the Other International category.

Turbines — In October 2003, we closed on the sale of three turbines and related equipment. The sale resulted in net cash proceeds of $70.7 million and a gain of approximately $21.9 million. Turbines are included in our All Other segment under the Other category.

Berrians Project — During the fourth quarter of 2003, we cancelled plans to construct the Berrians peaking facility on the land adjacent to our Astoria facility. Berrians was originally scheduled to commence operations in the summer of 2005; however, based on the remaining costs to complete and the current risk profile of merchant peaking units, the construction project was terminated. This resulted in a charge of approximately $14.3 million to write off the project's assets. Berrians is included in our Other North America segment.

TermoRio — TermoRio was a green field cogeneration project located in the state of Rio de Janeiro, Brazil. Based on the project's failure to meet certain key milestones, we exercised our rights under the project agreements to sell our debt and equity interests in the project to our partner, Petroleo Brasileiro S.A. Petrobras, or Petrobras. On May 17, 2002, Petrobras commenced an arbitration. On March 8, 2003, the arbitral tribunal decided most, but not all, of the issues in our favor and awarded us approximately US $80 million. On June 4, 2004, NRG Energy commenced a lawsuit in U.S. District Court for the Southern District of New York, seeking to enforce the arbitration award. On February 16, 2005, a conditional settlement agreement was signed with our former partner Petrobras, whereby Petrobras is obligated to pay us US $70.8 million. Such payment was received by us at a closing held on February 25, 2005. We have a note receivable of $57.3 million related to the arbitration award. The amounts received in excess of $57.3 million will be recorded to earnings in the first quarter of 2005. In addition to the settlement above, we retain the right to continue to seek recovery of US $12.3 million in a related dispute with a third party in Brazil. TermoRio is included in our All Other segment under the Other International category.

Meriden — During the third quarter of 2004, we reviewed the recoverability of our Meriden assets pursuant to SFAS No. 144 and recorded a charge of $15.0 million related to the impairment to realizable value of a turbine. An agreement for the sale of equipment previously located at the Meriden site has been executed and we expect to complete the sale in the first quarter of 2005. Meriden is included in our All Other segment under the Other category.

Kendall — In September 2004, we executed an agreement to sell our 1,160 MW generating plant in Minooka, Illinois to an affiliate of LS Power Associates, L.P and recorded a charge of approximately $24.5 million related to the impairment to realizable value. Under the terms of the agreement, we have the right to acquire a 40% interest in the plant within a 10-year period for a nominal amount. Therefore, the transaction was treated as a partial sale for accounting purposes. In December 2004 we completed the sale and received net proceeds of $1.0 million, resulting in a loss on sale of $2.0 million and a total loss of $26.5 million. Kendall is included in our Other North America segment.

Credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity experienced during the third quarter of 2002 were "triggering events" which required us to review the recoverability of our long-lived assets. Adverse economic conditions resulted in declining energy prices. Consequently, we determined that many of our construction projects and operational projects were impaired during the third quarter of 2002 and should be written down to fair market value. We recorded total impairment charges of $2.5 billion for the year ended December 31, 2002.

Restructuring Charges

We incurred $8.7 million of employee separation costs and advisor fees during 2003 until we filed for bankruptcy in May 2003. Subsequent to that date we recorded all advisor fees as reorganization costs. We incurred total restructuring charges of approximately $111.3 million for the year ended December 31, 2002 consisting of employee separation costs and advisor fees.

Fresh Start Adjustments

During the fourth quarter of 2003, we recorded a net credit of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) in connection with fresh start adjustments as discussed in Note 3.

Following is a summary of the significant effects of the reorganization and Fresh Start:

	(In millions)
Discharge of corporate level debt	$ 5,162
Discharge of other liabilities	811
Establishment of creditor pool	(1,040)
Receivable from Xcel	640
Revaluation of fixed assets	(1,392)
Revaluation of equity investments	(207)
Valuation of SO_2 emission credits	374
Valuation of out of market contracts, net	(400)
Fair market valuation of debt	108
Valuation of pension liabilities	(61)
Other valuation adjustments	(100)
Total Fresh Start adjustments	3,895
Less discontinued operations	(224)
Total Fresh Start adjustments — continuing operations	$ 4,119

Legal Settlement Charges

During the period January 1, 2003 to December 5, 2003, we recorded $462.6 million of legal settlement charges which consisted of the following. We recorded $396.0 million in connection with the resolution of an arbitration claim asserted by FirstEnergy Corp. As a result of this resolution, FirstEnergy retained ownership of the Lake Plant Assets and received an allowed general unsecured claim of $396.0 million under NRG Energy's Plan of Reorganization. In November 2003, we settled litigation with Fortistar Capital in which Fortistar Capital released us from all litigation claims in exchange for a $60.0 million pre-petition bankruptcy claim and an $8.0 million post-petition bankruptcy claim. We had previously recorded $10.8 million in connection with various legal disputes with Fortistar Capital; accordingly, we recorded an additional $57.2 million during November 2003. In November 2003, we settled our dispute with Dick Corporation in connection with Meriden Gas Turbines LLC through the payment of a general unsecured claim and a post-petition pre-confirmation payment. This settlement resulted in our recording an additional liability of $8.0 million in November 2003.

In August 1995, we entered into a Marketing, Development and Joint Proposing Agreement, or the Marketing Agreement, with Cambrian Energy Development LLC, or Cambrian. Various claims arose in connection with the Marketing Agreement. In November 2003, we entered into a settlement agreement with Cambrian where we agreed to transfer our 100% interest in three gasco projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville) and our 50% interest in two genco projects (MM Phoenix and MM Woodville) to Cambrian. In addition, we paid approximately $1.8 million in settlement of royalties incurred in connection with the Marketing Agreement. We had previously recorded a liability for royalties owed to Cambrian, therefore, we recorded an additional $1.4 million during November 2003.

Note 9 — Asset Retirement Obligation

Effective January 1, 2003, we adopted SFAS No. 143, *"Accounting for Asset Retirement Obligations"* or SFAS No. 143. SFAS No. 143 requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. 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. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

We identified certain retirement obligations within our power generation operations in the Northeast region, the South Central region and Australia. We also identified retirement obligations within our All Other segment under the Alternative Energy category and the Non-Generation category. These asset retirement obligations are related primarily to the future dismantlement of equipment on leased property and environment obligations related to ash disposal site closures and fuel storage facilities. We also identified other asset retirement obligations including plant dismantlement that could not be calculated because the assets associated with the retirement obligations were determined to have an indeterminate life. The adoption of SFAS No. 143 resulted in recording a $2.6 million increase to property, plant and equipment and a $4.2 million increase to other long-term obligations. The cumulative effect of adopting SFAS No. 143 was recorded as a $0.6 million increase to depreciation expense and a $1.6 million increase to cost of majority-owned operations in the period from January 1, 2003 to December 5, 2003 as we considered the cumulative effect to be immaterial.

The following represents the balances of the asset retirement obligation as of January 1, 2003 and the additions and accretion of the asset retirement obligation for the period January 1, 2003 through December 5, 2003, the period of December 6, 2003 through December 31, 2003 and the year ended December 31, 2004. The asset retirement obligation is included in other long-term obligations in the consolidated balance sheet. Prior to December 5, 2003, we completed our annual review of asset retirement obligations. As part of that review we made revisions to our previously recorded obligation in the amount of $4.0 million. The revisions included identification of new obligations as well as changes in costs required at retirement date. As a result of adopting Fresh Start we revalued our asset retirement obligations on December 6, 2003. We recorded an additional asset retirement obligation of $7.3 million in connection with fresh start reporting. This amount results from a change in the discount rate used between adoption and fresh start reporting as of December 5, 2003, equal to 500 to 600 basis points.

	Reorganized NRG					
	Beginning Balance December 6, 2003	Accretion for Period December 6 - December 31, 2003	Ending Balance December 31, 2003	Additions for Year Ended December 31, 2004	Accretion for Year Ended December 31, 2004	Ending Balance December 31, 2004
	(In thousands)					
Northeast Region	$11,691	$ 59	$11,750	$ 660	$ 810	$13,220
South Central Region	2,623	15	2,638	—	184	2,822
Australia	9,116	322	9,438	2,854	1,683	13,975
Alternative Energy	830	5	835	—	58	893
Non-generation	1,326	7	1,333	—	93	1,426
Total asset retirement obligation	$25,586	$408	$25,994	$3,514	$2,828	$32,336

	Predecessor Company				
Description	Beginning Balance January 1, 2003	Revisions to Estimate	Accretion for Period Ended December 5, 2003	Adjustment for Fresh Start Reporting	Ending Balance December 5, 2003
	(In thousands)				
Northeast Region	$ 2,045	$4,034	$ 634	$4,978	$11,691
South Central Region	396	—	57	2,170	2,623
Australia	5,834	—	3,282	—	9,116
Alternative Energy	629	—	73	128	830
Non-generation	1,171	9	93	53	1,326
Total asset retirement obligation	$10,075	$4,043	$4,139	$7,329	$25,586

The following represents the pro-forma effect on our net income for the period January 1, 2003 to December 5, 2003 and for the year ended December 31, 2002, as if we had adopted SFAS No. 143 as of January 1, 2002:

	Predecessor Company	
	For the Period January 1- December 5, 2003	Year Ended December 31, 2002
	(In thousands)	
Income (loss) from continuing operations as reported	$2,949,078	$(2,788,452)
Pro-forma adjustment to reflect retroactive adoption of SFAS No. 143	2,154	(677)
Pro-forma income (loss) from continuing operations	$2,951,232	$(2,789,129)
Net income (loss) as reported	$2,766,445	$(3,464,282)
Pro-forma adjustment to reflect retroactive adoption of SFAS No. 143	2,154	(677)
Pro-forma net income (loss)	$2,768,599	$(3,464,959)

Note 10 — Inventory

Inventory, which is stated at the lower of weighted average cost or market, consists of:

	Reorganized NRG	
	December 31, 2004	December 31, 2003
	(In thousands)	
Fuel oil	$114,092	$ 75,272
Coal	74,646	59,555
Natural gas	392	856
Other fuels	106	75
Spare parts	54,113	54,522
Emission credits	4,218	4,478
Other	443	168
Total inventory	$248,010	$194,926

Note 11 — Notes Receivable and Other Investments

Notes receivable consist primarily of fixed and variable rate notes secured by equity interests in partnerships and joint ventures.

The notes receivable and other investments are as follows:

	Reorganized NRG	
	December 31, 2004	December 31, 2003
	(In thousands)	
Investment in Bonds		
Audrain County, due December 2023, 10%(1)	$239,930	$239,930
Notes Receivable		
O'Brien Cogen II, due 2008, non-interest bearing	—	692
Omega Energy, LLC, due 2004, 12.5%	3,744	3,708
Omega Energy II, LLC, due 2009, 11%	1,583	1,583
Bullock Development Corporation, due November 2005, 8.5%	73	84
Elk River — GRE, due December 31, 2008, non-interest bearing	1,278	1,564
Dakota Wood Grinding	24	134
Audrain Generating LLC	—	118
Termo Rio (via NRGenerating Luxembourg (No. 2) S.a.r.l), 8.0%	57,323	57,323
Other		
Saale Energie GmbH, due August 31, 2021, 13.88% (direct financing lease) (2)	461,762	451,449
Notes receivable and bonds — non-affiliates	765,717	756,585
Reserve for uncollectible notes receivable	(3,794)	—
Notes receivable, net	761,923	756,585
NEO notes to various affiliates due primarily 2012, prime +2%	4,000	9,419
NRG (LSP Nelson)	—	200
Saale Energie GmbH, indefinite maturity date, 4.75%-7.79%(3)	119,644	111,892
Northbrook Texas LLC, due February 2024, 9.25%	8,804	8,841
Notes receivable — affiliates	132,448	130,352
Reserve for uncollectible notes receivable	(4,402)	—
Notes receivable — affiliates, net	128,046	130,352
Subtotal	889,969	886,937
Less current maturities	85,447	65,341
Total	$804,522	$821,596

(1) Investment in bonds is comprised of marketable debt securities. These securities consist of municipal bonds of Audrain County, Missouri which mature in 2023. These investments in bonds are classified as held to maturity and are recorded at amortized cost. The carrying value of these bonds approximates fair value. The Audrain County bonds are pledged as collateral for the related debt owed to Audrain County. As further described in Note 18, this transaction has an offsetting obligation.

(2) Saale Energie GmbH has sold 100% of its share of energy from the Schkopau power plant under a 25-year contract, which is more than 83% of the useful life of the plant. The direct financing lease receivable amount was calculated based on the present value of the income to be received over the life of the contract.

(3) Saale Energie GmbH entered into a note receivable with Kraftwerke Schkopau GBR, a partnership between Saale Energie GmbH and E.On Kraftwerke GmbH. The note was used to fund Saale's initial capital contribution to the partnership and to cover project liquidity shortfalls during construction of a power plant. The note is subject to repayment upon the disposition of the Schkopau plant.

Note 12 — Property, Plant and Equipment

The major classes of property, plant and equipment were as follows:

	Depreciable Lives	Reorganized NRG December 31, 2004	Reorganized NRG December 31, 2003	Average Remaining Useful Life
		(In thousands)		
Facilities and equipment	1-42 Years	$3,414,189	$3,732,391	15
Land and improvements		129,716	134,888	
Office furnishings and equipment	2-10 Years	20,753	18,186	3
Construction in progress		17,429	139,171	
Total property, plant and equipment		3,582,087	4,024,636	
Accumulated depreciation		(207,536)	(11,800)	
Net property, plant and equipment		$3,374,551	$4,012,836	

Note 13 — Investments Accounted for by the Equity Method

We have investments in various international and domestic energy projects. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships, because the ownership structure prevents us from exercising a controlling influence over operating and financial policies of the projects. Under this method, equity in pretax income or losses of domestic partnerships and, generally, in the net income or losses of international projects, are reflected as equity in earnings of unconsolidated affiliates.

A summary of certain of our more significant equity-method investments, which were in operation at December 31, 2004, is as follows:

Name	Geographic Area	Economic Interest
West Coast Power	USA	50%
James River	USA	50%
NRG Saguaro LLC	USA	50%
Rocky Road Power	USA	50%
Gladstone Power Station	Australia	37.5%
MIBRAG GmbH	Germany	50%
Enfield	UK	25%
Central and Eastern European Energy Power Fund	Various	22.2%
Scudder LA Power Fund I	Latin America	25%

During 2004, we sold our equity investments in Commonwealth Atlantic Limited Partnership, four NEO investments (Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC), Calpine Cogeneration, Loy Yang, Kondapalli, and ECKG. Summarized financial information for investments in unconsolidated affiliates accounted for under the equity method is as follows:

	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
		(In thousands)		
Operating revenues	$2,427,760	$ 268,348	$ 2,212,280	$2,394,256
Costs and expenses	1,965,915	202,725	2,035,812	2,284,582
Net income	$ 461,845	$ 65,623	$ 176,468	$ 109,674
Current assets	$ 844,821	$ 829,525	$ 783,669	$1,069,239
Noncurrent assets	2,902,798	6,541,003	6,452,014	6,853,250
Total assets	$3,747,619	$7,370,528	$ 7,235,683	$7,922,489
Current liabilities	$ 205,459	$1,275,724	$ 1,215,827	$1,075,785
Noncurrent liabilities	1,739,968	3,592,342	3,528,600	3,861,285
Equity	1,802,192	2,502,462	2,491,256	2,985,419
Total liabilities and equity	$3,747,619	$7,370,528	$ 7,235,683	$7,922,489
NRG's share of equity	$ 808,883	$1,051,959	$ 1,079,336	$1,171,726
NRG's share of net income	$ 159,825	$ 13,521	$ 170,901	$ 68,996

We have ownership interests in two companies that were considered significant as defined by applicable SEC regulations as of December 31, 2004: West Coast Power LLC and Enfield Energy Centre Limited. We account for our investments using the equity method. Our carrying value of equity investments is impacted by impairments, unrealized gains and losses on derivatives and movements in foreign currency exchange rates as well as other adjustments.

West Coast Power LLC Summarized Financial Information

We have a 50% interest in West Coast Power LLC. Upon adoption of Fresh Start we adjusted our investment in West Coast Power to fair value as of December 6, 2003. In accordance with APB Opinion 18, we have reconciled the value of our investment as of December 6, 2003 to our share of West Coast Powers partner's equity. As a result of pushing down the impact of Fresh Start to the project's balance sheet, we determined that a contract based intangible asset with a one year remaining life, consisting of the value of West Coast Power's CDWR energy sales contract, must be established and recognized as a basis adjustment to our share of the future earnings generated by West Coast Power. This adjustment reduced our equity earnings in the amount of $115.8 million for the year ended December 31, 2004 until the contract expired in December 2004. Offsetting this reduction in earnings is a favorable adjustment to reflect a lower depreciation expense resulting from the corresponding reduced value of the project's fixed assets from Fresh Start reporting. During the year ended December 31, 2004 we recorded equity earnings of $68.9 million for West Coast Power after adjustments for the reversal of $31.7 million project-level depreciation expense, offset by a decrease in earnings related to $115.8 million amortization of the intangible asset for the CDWR contract. During the period December 6, 2003 through December 31, 2003 we recorded equity earnings of $9.4 million for West Coast Power after adjustments for the reversal of $2.6 million project-level depreciation expense, offset by a decrease in earnings related to $8.8 million amortization of the intangible asset for the CDWR contract. The following table summarizes financial information for West Coast Power LLC, including interests owned by us and other parties for the periods shown below:

Results of Operations

	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
		(In thousands)		
Operating revenues	$1,334	$53	$643	$585
Operating income	304	31	201	48
Net income (pre-tax)	306	31	202	34

Financial Position

	December 31, 2004	December 31, 2003
	(In thousands)	
Current assets	$430	$257
Other assets	394	454
Total assets	$824	$711
Current liabilities	$ 83	$ 55
Other liabilities	5	8
Equity	736	648
Total liabilities and equity	$824	$711

Enfield Energy Centre Limited

We own a 25% interest in Enfield Energy Centre Limited, or EECL, located in Enfield, North London, UK. EECL owns and operates a 396 MW, natural gas-fired combined cycle gas turbine power station. EECL sells electricity generated from the plant in North London and the gas generated from the plant under a long-term gas supply contract. Enfield has a long-term agreement that effectively fixes the purchase price of its gas supply. The purpose of the contract, which was executed in August 1997 and extends through October 2014, is to mitigate the risk associated with fluctuations in the price of gas utilized in the generation of electricity at our facility. This contract is considered a derivative as defined by SFAS No. 133, and is afforded mark-to-market accounting treatment. We are subject to volatility in earnings associated with fluctuations in the market price of gas. Enfield has the ability to consume the gas for generation, and therefore our risk of loss associated with the contract is minimal. Given an increase in the price of natural gas in the UK market during the course of 2004, we recorded gains of $23.3 million associated with the value of this contract.

Note 14 — Decommissioning Funds

We are required by the Louisiana Department of Environmental Quality, or LADEQ, to rehabilitate our Big Cajun II ash and wastewater impoundment areas, subsequent to the Big Cajun II facilities' removal from service. On July 1, 1989, a guarantor trust fund, or the Solid Waste Disposal Trust Fund, was established to accumulate the estimated funds necessary for such purpose. Approximately $1.1 million was initially deposited in the Solid Waste Disposal Trust Fund in 1989, and $116,000 has been funded annually thereafter, based upon an estimated future rehabilitation cost (in 1989 dollars) of approximately $3.5 million and the remaining estimated useful life of the Big Cajun II facilities. At December 31, 2004 and 2003, the carrying value of the trust fund investments was approximately $5.0 million and $4.8 million, respectively. The trust fund investments are comprised of various debt securities of the United States and are carried at amortized cost, which approximates their fair value. The amounts required to be deposited in this trust fund are separate from our calculation of the asset retirement obligation recorded for the Big Cajun II ash and wastewater impoundment areas discussed in Note 9.

Note 15 — Intangible Assets

Reorganized NRG

Upon the adoption of Fresh Start, we established certain intangible assets for power sales agreements and plant emission allowances. These intangible assets will be amortized over their respective lives based on a straight-line or units of production basis to resemble our realization of such assets.

Power sale agreements are amortized as a reduction to revenue over the terms and conditions of each contract. The weighted average remaining amortization period is two years for the power sale agreements. Emission allowances are amortized as additional fuel expense based upon the actual level of emissions from the respective plants through 2023. Aggregate amortization recognized for the year ended December 31, 2004 and the period December 6, 2003 to December 31, 2003 was approximately $49.8 million and $5.2 million, respectively. The annual aggregate amortization for each of the five succeeding years, starting with 2005, is expected to approximate $22.6 million in 2005, $16.5 million in 2006, $15.9 million in 2007, $10.5 million in 2008 and $10.0 million in 2009 for both the power sale agreements and emission allowances. The expected annual amortization of these amounts is expected to change as we relieve our tax valuation allowance, as explained below.

For the year ended December 31, 2004, we reduced our deferred tax valuation allowance by $64.3 million (see Note 24) and recorded a corresponding reduction of $55.5 million related to our intangible assets at our wholly-owned subsidiaries. The remaining $8.8 million was recorded as a reduction to our intangible asset related to our equity investments in West Coast Power (see Note 13). In accordance with SOP 90-7, any future income tax benefits realized from reducing the valuation allowance should first reduce intangible assets until exhausted, and thereafter be recorded as a direct addition to paid-in capital. Intangible assets were also reduced by $32.7 million consisting of a $10.4 million reduction in connection with the recognition of certain tax credits to be claimed on our New York state franchise tax return and $22.3 million of adjustments related to a true-up of certain other tax evaluations and the recognition of Itiquira Energetica S.A. preferred stock as debt for U.S. generally accepted accounting purposes.

Intangible assets consisted of the following:

	Power Sale Agreements	Emission Allowances	Total
		(In thousands)	
Original balance as of December 6, 2003	$ 64,055	$373,518	$437,573
Amortization	(5,212)	—	(5,212)
Balance as of December 31, 2003	58,843	373,518	432,361
Tax valuation adjustments	(5,308)	(50,180)	(55,488)
Other valuation adjustments	(1,521)	(31,204)	(32,725)
Amortization	(31,969)	(17,829)	(49,798)
Balance as of December 31, 2004	$ 20,045	$274,305	$294,350

Predecessor Company

We had intangible assets that were amortized and consisted of service contracts. Aggregate amortization expense for the period January 1, 2003 to December 5, 2003 and for the year ended December 31, 2002 was approximately $3.8 million and $2.7 million, respectively.

Note 16 — Accounting for Derivative Instruments and Hedging Activities

SFAS No. 133 *"Accounting for Derivative Instruments and Hedging Activities"* as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149 requires us to recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. If certain conditions are met, we may be able to designate our derivatives as cash flow hedges and defer the effective portion of the change in fair value of the derivatives in Accumulated Other Comprehensive Income (OCI) and subsequently recognize in earnings when the hedged items impact income. The ineffective portion of a cash flow hedge is immediately recognized in income.

For derivatives designated as hedges of the fair value of assets or liabilities, the changes in fair value of both the derivatives and the hedged items are recorded in current earnings. The ineffective portion of a hedging derivative instrument's change in fair values will be immediately recognized in earnings.

For derivatives that are neither designated as cash flow hedges or do not qualify for hedge accounting treatment, the changes in the fair value will be immediately recognized in earnings.

Under the guidelines established by SFAS No. 133, as amended, certain derivative instruments may qualify for the normal purchase and sale exception and are therefore exempt from fair value accounting treatment.

SFAS No. 133 applies to our energy related commodity contracts, interest rate swaps and foreign exchange contracts discussed in further detail below.

Derivative Financial Instruments

Energy Related Commodities

As part of our risk management activities, we manage the commodity price risk associated with our competitive supply activities and the price risk associated with power sales from our electric generation facilities. In doing so, we may enter into a variety of derivative and non-derivative instruments, including but not limited to the following:

- Forward contracts, which commit us to purchase or sell energy commodities in the future.
- Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument.
- Swap agreements, which require payments to or from counter-parties based upon the differential between two prices for a predetermined contractual (notional) quantity.
- Option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

The objectives for entering into such hedges include:

- Fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric generation operations.
- Fixing the price of a portion of anticipated fuel purchases for the operation of our power plants.
- Fixing the price of a portion of anticipated energy purchases to supply our load-serving customers.

At December 31, 2004 we had hedge and non-hedge energy related commodities financial instruments extending through March 2025. Our energy related contracts that are components of our derivative assets and liabilities as of December 31, 2004 are as follows:

- Electric forward and futures contracts sales of electricity economically hedging our generation assets forecasted output through 2006.
- Natural gas forward and futures contracts purchases of natural gas relating to the forecasted usage of our generation assets into 2005.

Also, at December 31, 2004 we had other energy related contracts that did not qualify as derivatives under the guidelines established by SFAS No. 133, or we elected to apply the normal purchase and sale exception as follows:

- Coal purchase contracts extending through 2007 (designated as normal purchases and disclosed as part of our contractual cash obligations. See Note 27 Commitments and Contingencies).
- Natural gas transportation and storage agreements (these contracts are not derivatives and are disclosed as part of our contractual cash obligations. See Note 27 Commitments and Contingencies).
- Load-following forward electric sales contracts extending through 2025 (these contracts are not considered derivatives).

No ineffectiveness was recognized on commodity cash flow hedges during the year ended December 31, 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003, or during the year ended December 31, 2002.

Our pre-tax earnings for the year ended December 31, 2004, the period December 6, 2003 through December 31, 2003, the period January 1, 2003 through December 5, 2003, and the year ended December 31, 2002 were affected by an unrealized gain of $80.8 million, an unrealized loss of $0.7 million, an unrealized gain of $53.7 million and a unrealized gain of $20.0 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the year ended December 31, 2004, we reclassified losses of $3.2 million from OCI to current period earnings. During the period December 6, 2003 through December 31, 2003 no gains or losses were reclassified from OCI to current-period earnings. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net gains recorded in OCI of $61.0 million on energy related derivative instruments accounted for as hedges. During the period January 1, 2003 through December 5, 2003, we reclassified gains of $112.5 million from OCI to current period earnings. During the year ended December 31, 2002, we reclassified gains of $83.7 million from OCI to current-period earnings. We expect to reclassify an additional $3.9 million of deferred gains to earnings during the next twelve months on energy related derivative instruments accounted for as hedges.

Interest Rates

We are exposed to changes in interest rates through our issuance of variable rate and fixed rate debt. In order to manage this interest rate risk, we have entered into interest-rate swap agreements. At December 31, 2004 our consolidating subsidiaries had various interest-rate swap agreements extending through June 2019 with combined notional amounts of $1.3 billion. If these swaps had been terminated at December 31, 2004 we would have owed the counter-parties $35.6 million.

At December 31, 2004 all of our interest rate swap arrangements have been designated as either cash flow or fair value hedges.

No ineffectiveness was recognized on interest rate swaps that qualify as hedges during the year ended December 31, 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003 and the year ended December 31, 2002.

Our pre-tax earnings for the year ended December 31, 2004 were increased by an unrealized gain of $0.4 million associated with changes in the fair value of interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133. One of these instruments is a $400 million swap to pay fixed, which was not designated as a hedge of the expected cash flows at March 31, 2004. As of April 1, 2004, this instrument was designated as a cash flow hedge under SFAS No. 133. As a result, changes in value subsequent to April 1, 2004 are deferred and recorded as part of OCI.

Our pre-tax earnings for the period December 6, 2003 through December 31, 2003 and the period January 1, 2003 through December 5, 2003 were increased by an unrealized gain of $2.0 million and decreased by an unrealized loss of $15.1 million, respectively, associated with changes in the fair value of interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

Our pre-tax earnings for the year ended December 31, 2002 were decreased by an unrealized loss of $32.0 million associated with changes in the fair value of interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the year ended December 31, 2004, we reclassified losses of $5.0 million from OCI to current period earnings. During the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003, losses of $0 and $29.7 million, respectively, were reclassified from OCI to current-period earnings. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net losses recorded in OCI of $65.9 million on interest rate swaps accounted for as hedges. During the year ended December 31, 2002, we reclassified gains of $0.9 million from OCI to current-period earnings. We do not expect to reclassify any deferred gains or losses to earnings during the next twelve months associated with interest rate swaps accounted for as hedges.

Foreign Currency Exchange Rates

To preserve the U.S. dollar value of projected foreign currency cash flows, we may hedge, or protect those cash flows if appropriate foreign hedging instruments are available. As of December 31, 2004 and 2003, neither we nor our consolidating subsidiaries had any outstanding foreign currency exchange contracts.

No ineffectiveness occurred on foreign currency cash flow hedges during the year ended December 31, 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003, or during the year ended December 31, 2002.

During the year ended December 31, 2004 and the period December 6, 2003 to December 31, 2003, our pre-tax earnings were not affected by any gain or loss associated with foreign currency hedging instruments not accounted for as hedges in accordance with SFAS No. 133.

Our pre-tax earnings for the period January 1, 2003 through December 5, 2003, and for the year ended December 31, 2002 were increased by an unrealized gain of $0.1 million and $0.3 million, respectively, associated with foreign currency hedging instruments not accounted for as hedges in accordance with SFAS No. 133.

During the year ended December 31, 2004, we reclassified losses of $0.2 million from OCI to current period earnings. During the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003, no amounts were reclassified from OCI to current period earnings. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net losses recorded in OCI of $0.2 million on foreign currency swaps accounted for as hedges. During the year ended December 31, 2002, we reclassified losses of $2.1 million from OCI to current period earnings. We do not expect to reclassify any deferred gains or losses to earnings during the next twelve months on foreign currency swaps accounted for as hedges.

Accumulated Other Comprehensive Income

The following table summarizes the effects of SFAS No. 133, as amended, on our other comprehensive income balance attributable to hedged derivatives for the year ended December 31, 2004 before income taxes:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Accum. OCI balance at December 31, 2003	$(1,953)	$ 1,600	$(170)	$ (523)
Unwound from OCI during period:				
— due to unwinding of previously deferred amounts	3,241	5,030	170	8,441
Mark to market of hedge contracts (net of tax of $4,273)	4,194	(4,643)	—	(449)
Accum. OCI balance at December 31, 2004	$ 5,482	$ 1,987	$ —	$7,469
Gains/(Losses) expected to unwind from OCI during next 12 months	$ 3,902	$ —	$ —	$3,902

During the year ended December 31, 2004, losses of approximately $8.4 million were reclassified from OCI to current period earnings due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also during the year ended December 31, 2004, we recorded a loss in OCI of $0.4 million related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133 as of December 31, 2004 was an unrecognized gain of approximately $7.5 million. We expect $3.9 million of deferred net gains on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

The following table summarizes the effects of SFAS No. 133, as amended, on our other comprehensive income balance attributable to hedged derivatives for the period December 6, 2003 to December 31, 2003 before income taxes:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Accum. OCI balance at December 6, 2003	$ —	$ —	$ —	$ —
Unwound from OCI during period:				
— due to unwinding of previously deferred amounts	—	—	—	—
Mark to market of hedge contracts	(1,953)	1,600	(170)	(523)
Accum. OCI balance at December 31, 2003	$(1,953)	$1,600	$(170)	$(523)

During the period ended December 31, 2003, we recorded a loss in OCI of approximately $0.5 million related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133, as amended, as of December 31, 2003 was an unrecognized loss of approximately $0.5 million.

The following table summarizes the effects of SFAS No. 133, as amended, on our other comprehensive income balance attributable to hedged derivatives for the period January 1, 2003 to December 5, 2003 before income taxes:

	Predecessor Company			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Accum. OCI balance at December 31, 2002	$ 129,496	$(102,957)	$(261)	$ 26,278
Unwound from OCI during period:				
— due to forecasted transactions probable of no longer occurring	—	32,025	—	32,025
— due to unwinding of previously deferred amounts	(112,501)	(2,280)	—	(114,781)
Mark to market of hedge contracts	43,979	7,358	56	51,393
Accum. OCI balance at December 5, 2003	60,974	(65,854)	(205)	(5,085)
— due to Fresh Start reporting write-off	(60,974)	65,854	205	5,085
Accum. OCI balance at December 6, 2003	$ —	$ —	$ —	$ —

During the period ended December 5, 2003, we reclassified losses of $32.0 million from OCI to current-period earnings as a result of the discontinuance of cash flow hedges because it is probable that the original forecasted transactions will not occur by the end of the originally specified time period. Additionally, gains of $114.8 million were reclassified from OCI to current period earnings during the period ended December 5, 2003 due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also during the period ended December 5, 2003, we recorded a gain in OCI of approximately $51.4 million related to changes in the fair values of derivatives accounted for as hedges. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net losses recorded in OCI of $5.1 million.

The following table summarizes the effects of SFAS No. 133, as amended, on our other comprehensive income balance attributable to hedged derivatives for the year ended December 31, 2002 before income taxes:

	Predecessor Company			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Accum. OCI balance at December 31, 2001	$142,919	$ (69,455)	$(2,363)	$ 71,101
Unwound from OCI during period:				
— due to forecasted transactions probable of no longer occurring	—	(23,263)	—	(23,263)
— due to termination of hedged items by counter-party	(6,130)	—	—	(6,130)
— due to unwinding of previously deferred amounts	(77,576)	22,337	2,075	(53,164)
Mark to market of hedge contracts	70,283	(32,576)	27	37,734
Accum. OCI balance at December 31, 2002	$129,496	$(102,957)	$ (261)	$ 26,278

During the year ended December 31, 2002, we reclassified gains of $23.3 million from OCI to current-period earnings as a result of the discontinuance of cash flow hedges because it is probable that the original forecasted transactions will not occur by the end of the originally specified time period. Also, gains of $6.1 million were reclassified from OCI to current period earnings due to the hedge items being terminated by the counter-parties. Additionally, gains of $53.2 million were reclassified from OCI to current period earnings during the year ended December 31, 2002 due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also during the year ended December 31, 2002, we recorded a gain in OCI of approximately $37.7 million related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133, as amended, as of December 31, 2002 was an unrecognized gain of approximately $26.3 million.

Statement of Operations

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the year ended December 31, 2004:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Revenue from majority-owned subsidiaries	$57,313	$ —	$—	$57,313
Cost of operations	(255)	—	—	(255)
Other income	—	—	—	—
Equity in earnings of unconsolidated subsidiaries	23,735	—	—	23,735
Interest expense	—	411	—	411
Total Statement of Operations impact before tax	$80,793	$411	$—	$81,204

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the period from December 6, 2003 through December 31, 2003:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Revenue from majority-owned subsidiaries	$(627)	$ —	$—	$ (627)
Cost of operations	508	—	—	508
Other income	—	—	—	—
Equity in earnings of unconsolidated subsidiaries	(630)	—	—	(630)
Interest expense	—	1,983	—	1,983
Total Statement of Operations impact before tax	$(749)	$1,983	$—	$1,234

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the period from January 1, 2003 through December 5, 2003:

	Predecessor Company			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Revenue from majority-owned subsidiaries	$30,027	$ —	$—	$ 30,027
Cost of operations	4,607	—	—	4,607
Other income	—	—	92	92
Equity in earnings of unconsolidated subsidiaries	19,022	—	—	19,022
Interest expense	—	(15,104)	—	(15,104)
Total Statement of Operations impact before tax	$53,656	$(15,104)	$92	$ 38,644

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the year ended December 31, 2002:

	Predecessor Company			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Revenue from majority-owned subsidiaries	$ 9,085	$ —	$ —	$ .9,085
Cost of operations	9,530	—	—	9,530
Equity in earnings of unconsolidated subsidiaries	1,426	970	—	2,396
Other income	—	—	344	344
Interest expense	—	(32,953)	—	(32,953)
Total Statement of Operations impact before tax	$20,041	$(31,983)	$344	$(11,598)

Note 17 — Creditor Pool and Other Settlements

A principal component of our plan of reorganization is a settlement with Xcel Energy in which Xcel Energy agreed to make a contribution consisting of cash (and, under certain circumstances, its stock) in the aggregate amount of up to $640 million to be paid in three separate installments following the effective date of our plan of reorganization. The Xcel Energy settlement agreement resolves any and all claims existing between Xcel Energy and us and/or our creditors and, in exchange for the Xcel Energy contribution, Xcel Energy received a complete release of claims from us and our creditors, except for a limited number of creditors who have preserved their claims as set forth in the confirmation order entered on November 24, 2003. We received $288.0 million, $328.5 million and $23.5 million from Xcel Energy on February 20, 2004, April 30, 2004 and May 28, 2004, respectively. We used the proceeds from the Xcel Energy settlement to reduce our creditor pool obligation. As of December 31, 2004 and 2003 the balance of our creditor pool obligation was $0.0 million and $540.0 million, respectively. On February 20, 2004, April 30, 2004, May 28, 2004 and October 29, 2004, we made payments of $163.0 million, $328.5 million, $23.5 million and $25.0 million, respectively. In addition, our other bankruptcy settlement obligation as of December 31, 2004 and 2003 was $175.6 million and $220.0 million, respectively. This obligation relates to the allowed claims against NRG Energy related to our Audrain and Pike facilities. See Note 27 — NRG FinCo Settlement. The net change in the balance of $44.4 million reflects the sale of certain of these assets, the proceeds of which were paid to the FinCo lenders.

Note 18 — Debt and Capital Leases

Long-term debt and capital leases consist of the following:

	Stated Rate	Effective Rate	Principal December 31, 2004	Fair Value Adjustment December 31, 2004	Principal December 31, 2003	Fair Value Adjustment December 31, 2003
	(Percent)		(In thousands)			
NRG Recourse Debt:						
NRG Energy 2nd priority senior notes, due December 15, 2013(4)(5)	8.00%	—%	$1,725,000	$ 9,790	$1,250,000	$ —
NRG New Credit Facility, due June 23, 2010	(1)	—	—	—	1,200,000	—
NRG Amended Credit Facility, due December 24, 2011	(1)	—	800,000	—	—	—
NRG Promissory Note, Xcel Energy, due June 5, 2006	3.00	9.00	10,000	(758)	10,000	(1,310)
NRG Project-Level, Non-Recourse Debt:						
NRG Peaker Finance Co. LLC, due June 2019	(1)	L+3.5(2)	300,876	(64,446)	311,373	(72,105)
Flinders Power Finance Pty, due September 2012	(1)	6.00	202,856	9,984	187,668	10,632
NRG Energy Center Minneapolis LLC, Senior secured notes, due 2013 and 2017, 7.12%-7.31%	(1)	L+2(2)	118,950	5,896	126,279	7,030
NRG Energy Center San Francisco LLC, Senior secured notes, due November 2004	10.61	L+2(2)	—	—	860	41
NRG Energy Center San Francisco LLC, Senior secured notes, due September 2008	7.63	L+2(2)	129	6	—	—
NRG Energy Center Pittsburgh LLC, senior secured notes, due November 2004	10.61	L+2(2)	—	—	1,550	66
Northbrook STS HydroPower, due March 2023	9.13	9.70	24,329	(893)	24,506	(930)
Northbrook Carolina Hydro, due December 2016	(1)	L+4(2)	2,375	(150)	2,475	(177)
Northbrook New York, due September 2018	(1)	L+3(2)	16,900	(297)	17,199	(315)

	Stated Rate	Effective Rate	Principal December 31, 2004	Fair Value Adjustment December 31, 2004	Principal December 31, 2003	Fair Value Adjustment December 31, 2003
	(Percent)		(In thousands)			
Camas Power Boiler LP, unsecured term loan, due June 2007	(1)	L+2(2)	6,275	(168)	8,628	(277)
Camas Power Boiler LP, revenue bonds, due August 2007	3.38	L+2(2)	4,475	(42)	5,765	(108)
Itiquira Energetica S.A., due December 2013	12.00		31,002	—	—	—
Itiquira Energetica S.A., due January 2012	(1)		20,078	—	—	—
Meriden promissory note, due May 2003	10.00	—	—	—	500	—
LSP Kendall Energy LLC, due November 2006	(1)	L+3.5(2)	—	—	487,013	(30,370)
Cobee term loans, due July 2007(3)	(1)	15.00	—	—	31,800	(2,815)
Hsin Yu, due various(3)	(1)	—	—	—	85,300	(44,480)
LSP Energy LLC (Batesville), due 2014 and 2025, 7.16%-8.16%(3)	(1)	8.23-9.00	—	—	307,175	(12,292)
PERC notes, due 2017 and 2018(3)	6.75	L+2(2)	—	—	26,265	(1,203)
Capital leases:						
Saale Energie GmbH, Schkopau capital lease, due 2021	(1)	—	303,803	—	342,469	—
Audrain County, MO, capital lease, due December 2023	10.00	—	239,930	—	239,930	—
Conemaugh Fuels LLC, capital lease, due August 2014	7.00	—	218	—	—	—
NRG Processing Solutions, capital lease, due November 2004	9.00	L+2(2)	—	—	326	10
Subtotal			3,807,196	(41,078)	4,667,081	(148,603)
Less discontinued operations			—	—	450,540	(61,073)
Less current maturities				2,798	901,242	(100,013)
Total			$3,297,742	$(43,876)	$3,315,299	$ 12,483

(1) Distinguishes debt with various interest rates.

(2) L+ equals LIBOR plus x%

(3) Discontinued operations.

(4) Fair value adjustment as of December 31, 2004 reflects $16.1 million reduction for an interest rate swap.

(5) $415.8 million in bonds have been paid in 2005, of which $375.0 million were redeemed and $40.8 million were assumed by NRG Energy and therefore remain outstanding.

As a result of adopting Fresh Start on December 6, 2003, the fair value of long-term debt was calculated using the indicated effective interest rates which approximate market rates. The fair value adjustments for these notes and capital leases are amortized into interest expense using the effective interest rate method. A fair value adjustment was not necessary for the senior notes and the credit facility as both of these obligations were entered into subsequent to Fresh Start. For those notes and capital leases where market pricing was not available, we used carrying amounts, which we believe approximated the market values as of December 6, 2003.

As of December 31, 2004, we have timely made scheduled payments on interest and/or principal on all of our recourse debt and were not in default under any of our related recourse debt instruments. Additionally, we are not in default on any obligations to post collateral.

While we were in bankruptcy, we ceased accruing interest on unsecured debt that was not probable of being paid.

Short-Term Debt

Short-term debt at December 31, 2003 consisted of a $19.0 million revolving loan undertaken by Itiquira Energetica S.A., an indirectly wholly-owned subsidiary of ours. This loan was replaced by a long-term financing arrangement on July 15, 2004.

Long-term Debt and Capital Leases

Senior Securities

On December 23, 2003, we issued $1.25 billion in 8% Second Priority Notes, due and payable on December 15, 2013. On January 28, 2004, we issued an additional $475.0 million in Second Priority Notes, under the same terms and indenture as our December 23, 2003 offering. Proceeds of the offering were used to prepay $503.5 million of the outstanding principal on the term loan under the New Credit Facility. Included in refinancing expenses for the year ended December 31, 2004 are $15 million of prepayment penalties and a $15 million write-off of deferred financing costs related to refinancing certain amounts of our term loans with the additional $475.0 million in Second Priority Notes.

The Second Priority Notes are general obligations of ours. They are secured on a second-priority basis by security interests in all assets of ours, with certain exceptions, subject to the liens securing our obligations under the Amended Credit Agreement (described below) and any other priority lien debt. The notes are effectively subordinated to our obligations under the Amended Credit Facility and any other priority lien obligation, which are secured on a first-priority basis by the same assets that secure the Second Priority Notes. The Second Priority Notes are senior in right of payment to any future subordinated indebtedness. Interest on the Second Priority Notes accrues at the rate of 8.0% per annum and is payable semi-annually in arrears on June 15 and December 15, commencing on June 15, 2004. Accrued but unpaid interest was $6.1 million and $2.2 million as of December 31, 2004 and 2003, respectively. As of December 31, 2004, we had an interest rate swap in place to exchange fixed-rate interest payments for floating-rate interest payments. This swap agreement became effective March 26, 2004 and terminates December 15, 2013. The swap agreement has provisions for early termination that are linked to any prepayment of the Second Priority Notes. Under the agreement, we agree to pay semi-annually in arrears, commencing June 15, 2004, a floating interest rate on a notional amount of $400.0 million, and receive semi-annually in arrears a fixed interest rate payment on the same notional amount. The floating interest rate is based upon six-month LIBOR plus a spread. Depending on market interest rates, we or the swap counter-party may be required to post collateral on a daily basis in support of this swaps, to the benefit of the other party. On December 31, 2004 and as of March 21, 2005, we had $0 and $4.1 million in collateral posted.

When we issued the Second Priority Senior Secured Notes in December 2003, we entered into a Registration Rights Agreement with the purchasers of the Notes. Under the Registration Rights Agreement, we were required to file a Registration Statement with the SEC by May 21, 2004 (150 days after the issuance of the Notes) to permit the bonds to be publicly traded. When we did not meet this deadline, we were required to accrue liquidated damages, starting May 22, 2004 until the exchange is executed. Accrued amounts are due and payable on the same dates that we pay interest (semi-annually on June 15 and December 15, or upon early redemption). Liquidated damages are calculated as a rate per $1000 outstanding on a weekly basis, with the rate increasing from $0.05 up to $0.50 per $1000 each 90 day period, commencing May 22, 2004. Accrued but unpaid liquidated damages were $0.6 million and $0.0 million as of December 31, 2004 and 2003, respectively. As of December 31, 2004, we were accruing liquidated damages of $0.15 per $1000 per week, or $0.3 million per week.

In January 2005 and in March 2005, we used existing cash to purchase, at market prices, $25 million and $15.8 million, respectively, in face value of our Second Priority Notes. On February 4, 2005, we redeemed $375.0 million in Second Priority Notes. At the same time, we paid $30.0 million for the early redemption premium on the redeemed notes, $4.1 million in accrued but unpaid interest on the redeemed notes and $0.4 million in accrued but unpaid liquidated damages on the redeemed notes.

Also on December 23, 2003, concurrently with the initial offering of the Second Priority Notes, we and PMI entered into the New Credit Facility for up to $1.45 billion with Credit Suisse First Boston, as Administrative Agent, and Lehman Commercial Paper, Inc., as Syndication Agent and a group of lenders. The New Credit Facility consisted of a $950.0 million, six and a half-year senior secured term loan facility, a $250.0 million funded letter of credit facility, and a four-year revolving credit facility in an amount up to $250.0 million. The balance outstanding under this facility was $1.2 billion as of December 31, 2003.

On December 24, 2004, the credit facility was amended and restated, or the Amended Credit Facility, whereby we repaid outstanding amounts and issued a $450.0 million, seven-year senior secured term loan facility, a $350.0 million funded letter of credit facility, and a three-year revolving credit facility in an amount up to $150.0 million. At that time, we paid $13.8 million in prepayment breakage costs, $3.2 million in accrued but unpaid interest and fees, and wrote off $27 million of deferred financing costs associated with the amendment. Refinancing expenses for the year ended December 31, 2004 included the $13.8 million of prepayment penalties and the $27 million write-off of deferred financing costs. The balance outstanding under this facility was $800.0 million as of December 31, 2004. Other expenses include commitment fees on the undrawn portion of the revolving credit facility, participation fees for the credit-linked deposit and other fees.

Refinancing expenses were $71.6 million for the year ended December 31, 2004. This amount includes $15 million of prepayment penalties and a $15 million write-off of deferred financing costs related to refinancing certain amounts of our term loans with additional Second Priority Notes in January 2004 and $13.8 million of prepayment penalties and a $27 million write-off of deferred financing costs related to refinancing the senior credit facility in December 2004.

As of December 31, 2004, the $350.0 million letter of credit facility was fully funded and reflected as a funded letter of credit on the December 31, 2004 balance sheet. As of December 31, 2004, $157.1 million in letters of credit had been issued under this facility, leaving $192.9 million available for future issuances. Most of these letters of credit are issued in support of our obligations to perform under commodity agreements, financing or other arrangements. These letters of credit expire within one year of issuance, and it is not unusual for us to renew many of them on similar terms.

The Amended Credit Facility is secured by, among other things, first-priority perfected security interests in all of the property and assets owned at any time or acquired by us and our subsidiaries, other than the property and assets of certain excluded project subsidiaries, foreign subsidiaries and certain other subsidiaries, with some exceptions.

The Amended Credit Facility bears interest at an interest rate of 1.875% over LIBOR which was 2.42% as of December 31, 2004. We can elect to convert to a rate of 0.875% over prime at the end of any LIBOR period. As of December 31, 2004, we had an interest rate swap in place to hedge against fluctuations in prime or LIBO rates. The swap agreement became effective March 26, 2004 and terminates March 31, 2006. Under the agreement, we agree to pay quarterly a fixed interest rate on a notional amount of $400.0 million, commencing on March 31, 2004, and receive quarterly a floating-rate interest rate payment on the same notional amount. The floating rate is based upon three-month LIBOR, subject to a floor.

Significant affirmative covenants of the Second Priority Notes and the Amended Credit Facility include the provision of financial reports, reports of any events of default or developments that could have a material adverse effect, provision of notice with respect to changes in corporate structure or collateral. In addition, the borrower must maintain segregated cash accounts for certain deposits or settlements and meet certain ratio tests. Certain restricted payments are permitted under both credit facilities, pursuant to our meeting certain ratio tests and the absence of any defaults.

Significant negative covenants of the Second Priority Notes and the Amended Credit Facility include limitations on additional indebtedness, liens, acquisitions and certain asset dispositions.

Events of default under the Second Priority Notes and the Amended Credit Facility include materially false representation or warranty; payment default on principal or interest; covenant defaults; cross-defaults to material indebtedness; our or a material subsidiary's bankruptcy and insolvency; material unpaid judgments; ERISA events; failure to be perfected on any material collateral; and a change in control.

On December 5, 2003, we entered into a $10 million promissory note with Xcel Energy. The note accrues interest at a rate of 3% per year, payable quarterly in arrears. All principal is due at maturity on June 5, 2006.

Project Financings

The following are descriptions of certain indebtedness of NRG's project subsidiaries that remain outstanding on December 31, 2004. The indebtedness described below is non-recourse to NRG, unless otherwise described.

Peakers

In June 2002, NRG Peaker Financing LLC, or Peakers, an indirect wholly-owned subsidiary, issued $325 million in floating rate bonds due June 2019. Peakers subsequently swapped such floating rate debt for fixed rate debt at an all-in cost of 6.67% per annum. Principal, interest, and swap payments are guaranteed by XL Capital Assurance, or XLCA, through a financial guaranty insurance policy. Such notes are also secured by, among other things, substantially all of the assets of and membership interests in Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Sterlington Power LLC, NRG Rockford LLC, NRG Rockford II LLC and NRG Rockford Equipment LLC (all subsidiaries of NRG). As of December 31, 2004, $300.9 million in principal remained outstanding on these bonds. In January 2004, terms of the financing arrangement were restructured, at which time we issued a $36.2 million letter of credit, under our corporate funded letter of credit facility to the Peakers' Collateral Agent. The letter of credit may be drawn if the project is unable to meet principal or interest payments. There are no provisions requiring us to replenish the letter of credit once it is fully drawn.

Flinders

At December 31, 2004, NRG Flinders, a wholly-owned subsidiary of NRG, had AUD 315 million available in senior debt bank financing pursuant to two bank facilities. The first was an AUD 150 million floating-rate syndicated facility that matured in September 2012. The second facility, intended to fund the refurbishment of the Playford station, allowed Flinders to draw up to AUD 137 million (approximately US $107 million) at a floating-rate of interest on drawn amounts and matures coterminous with the first facility. As of December 31, 2004, outstanding principal was AUD 259.2 million (approximately US $202.9 million) on the two facilities. In addition, Flinders had an AUD 20.0 million (approximately US $15.7 million) working capital facility. At December 31, 2004 the facility was undrawn. Flinders agreed with the lenders to hedge not less than 60% of its floating interest exposure until September 30, 2005 and not less than 40% of its floating interest exposure through the end of the loan. Under this financing arrangement, Flinders was required to fully fund, and NRG was required to guarantee, a debt service reserve account. The reserve amount of AUD 70 million (approximately US $54.8 million) was fully funded as of December 31, 2004.

In February 2005, Flinders amended its floating-rate debt facility of AUD 279.4 million (approximately US $218.5 million). The amendment extended the maturity to February 2017, reduced borrowing costs and reserve requirements, minimized debt service coverage ratios, removed mandatory cash sharing arrangements, and made other minor modifications to terms and conditions. The facility includes an AUD 20 million (approximately US $15.7 million) working capital and performance bond facility. NRG Flinders is required to maintain interest-rate hedging contracts on a rolling 5-year basis at a minimum level of 60% of principal outstanding. Upon execution of the amendment, a voluntary principal prepayment of AUD 50 million (approximately US $39.1 million) was made, reducing the principal balance of the term loan to AUD 209.2 million (approximately US $163.7 million). As of March 21, 2005, the revolver remained undrawn.

NRG Thermal

NRG Thermal LLC, or NRG Thermal, has several subsidiaries with outstanding long-term debt. Such indebtedness is secured principally by the subsidiaries' long-term assets and is guaranteed by NRG Thermal and "cross-collateralized" by NRG Thermal's ownership interests in all of its subsidiaries. In July 2002, NRG Energy Center Minneapolis LLC issued $55 million of 7.25% Series A notes due August 2017, of which $50.0 million remained outstanding as of December 31, 2004; $20 million of 7.12% Series B notes due August 2017, of which $18.2 million remained outstanding as of December 31, 2004; and in August 1993, NRG Energy Center Minneapolis LLC issued $84 million of 7.31% senior secured notes due June 2013, of which $50.8 million remained outstanding as of December 31, 2004. NRG Energy Center San Francisco LLC has issued $360 thousand of 7.63% senior secured term notes due September 2008, of which $129 thousand remained outstanding at December 31, 2004. The NRG Energy Center San Francisco LLC 10.61% senior secured term notes and the NRG Energy Center Pittsburgh LLC 10.61% senior secured term notes were paid in full on November 5, 2004.

STS Hydropower

STS Hydropower, LTD, or STS Hydropower, which is indirectly 50% owned by NEO Corporation, a wholly-owned subsidiary of NRG Energy, entered into a Note Purchase Agreement in March 1995 with Allstate Life Insurance Co., or Allstate. Allstate purchased from STS Hydropower $22 million of 9.155% senior secured debt due December 30, 2016. The agreement was amended in 1996 to add $700,000 of 8.24% senior secured debt due March 2011. The debt is secured by substantially all assets of and interest in STS Hydropower. Because of poor hydroelectric output due to drought conditions, no principal or interest payments have been made on this loan facility since October 2001. In May 2003, the facility was restructured and currently has a maturity of March 2023 and an interest rate of 9.133%. As of December 31, 2004, all required covenants under the restructured facility had been met and $24.3 million was outstanding.

Northbrook Carolina Hydro and Northbrook New York

Northbrook Carolina Hydro, LLC, or NCH, which is indirectly 50% owned by NEO, entered into a $2.6 million loan arrangement in December 2001 with Heller Financial. In order to secure the NCH financing, Heller Financial's credit agreement with Northbrook New York LLC, or NNY, was amended to cross-collateralize the NCH and NNY notes. NNY is indirectly 70% owned by the NEO Corporation. In 2002, GE Capital Services purchased Heller Financial and assumed the loan facility. This loan facility is secured by substantially all hydroelectric assets of and membership interests in NCH and NNY. The NCH facility bears interest at an interest rate of LIBOR plus 4% and matures in December 2016. As of December 31, 2004, the outstanding balance was $2.4 million.

In September 1999, NNY entered into a $17.5 million term loan agreement with Heller Financial. In addition to the term loan, there is a $1.5 million revolver, which was undrawn as of December 31, 2004. In December 2001, the credit agreement with Heller Financial was amended to include $2.6 million of financing for NCH, an affiliated entity, and to cross-collateralize the NNY and NCH notes. Heller Financial was subsequently purchased by GE Capital Services, which assumed the notes. The NNY facility bears an interest rate of LIBOR plus 3% and matures in December 2018. It is secured by substantially all of the assets of and membership interests in the NNY and NCH facilities. The principal amount outstanding as of December 31, 2004 was $16.9 million.

Camas

In November 1990, Clark County, Washington issued $15.0 million in aggregate principal amount of 7.2% fixed interest Series A tax-exempt bonds due August 15, 2007 to fund the construction of the Camas project. The bonds were re-marketed with a 4.65% interest rate in August 1997 and again at a 3.375% interest rate in August 2002. This facility pursuant to the indenture, can no longer be re-marketed. As of December 31, 2004, $4.5 million remains outstanding. In 1997, Camas also acquired a $19.6 million floating-rate bank loan from Fort James Corporation, maturing in June 2007. The principal outstanding on this facility was $6.3 million as of December 31, 2004.

Itiquira Energetica S.A.

On July 15, 2004, Itiquira Energetica S. A., a majority-owned subsidiary of ours, executed a long-term financing arrangement with União de Bancos Brasileiros S.A., or Unibanco, for a 55 million Brazilian reals term loan maturing in January 2012. The facility bears a floating interest rate and amortizes on a schedule that is indexed to certain foreign exchange rates. The facility replaces a revolving loan undertaken with Unibanco which was classified as short-term debt on our balance sheet as of December 31, 2003. The current facility is classified as long-term debt as of December 31, 2004. The principal obligation as of December 31, 2004 was $20.1 million. Eletrobrãs owns preferred shares in Itiquira, which for U.S. GAAP purposes are reflected as debt. The preferred shares accrue cumulative dividends of 12% per year, payable only at such time Itiquira has sufficient retained profits or reserves. The balance at December 31, 2004 was $31.0 million.

LSP Kendall

The LSP Kendall Energy LLC, or LSP Kendall, credit facility was non-recourse to us and consisted of a construction and term loan, working capital and letter of credit facilities. As of December 31, 2003, there were borrowings totaling $487.0 million outstanding under the facility at a weighted average annual interest rate of 2.58%. LSP Kendall was sold on December 1, 2004.

Capital Leases

Schkopau

The Kraftwerke Schkopau GbR, or Schkopau, partnership, which is indirectly 41.9% owned by NRG, issued debt pursuant to multiple facilities totaling approximately €886.8 million (approximately US $1,203.1 million) to finance a construction project. As of December 31, 2004, €463.5 million (approximately US $628.8 million) remained outstanding. Interest on the individual loans accrues at fixed rates averaging 6.68% per annum, with maturities occurring between years 2005 and 2015. Schkopau is a partnership between Saale Energie GmbH, an NRG subsidiary and German Limited Liability Company, and E.ON Kraftwerke GmbH, a German Limited Liability Company. As a result, lenders to the project rely almost exclusively on the creditworthiness of E.ON Kraftwerke GmbH. Saale Energie remains liable to the lenders as a partner in the borrower, but there is no recourse to NRG.

Schkopau is not permitted to retain funds for its own account, so funds received from electricity sales are retained by the partners and Schkopau calls for funds from the partners on a pro rata basis to meet debt service payments as they fall due. In the early years of the project these were at a low level, which allowed Saale Energie to accumulate cash that in 1999 was lent upstream for use elsewhere within the NRG group. Saale Energie is now projecting that cash calls to meet debt service payments over the next four years will at times exceed the cash available to meet them. NRG agreed to cover the periodic shortfalls by way of partial repayments of an upstream loan followed by cash dividend payments on high levels to NRG in 2007. For U.S. GAAP purposes, the Schkopau debt obligations are classified as capital leases on its balance sheet. As of December 31, 2004 the capital lease obligation was $303.8 million.

Audrain

In connection with our acquisition of the Audrain facilities, we have recognized a capital lease on our balance sheet classified within long-term debt in the amount of $239.9 million as of December 31, 2004 and 2003. The capital lease obligation is recorded at the net present value of the minimum lease obligation payable. The lease terminates in December 2023. During the term of the lease only interest payments are due, no principal is due until the end of the lease. In addition, we have recorded, in notes receivable, an amount of approximately $239.9 million, which represents our investment in the bonds that the county of Audrain issued to finance the project. During December 2004, we received a notice of a waiver of a $24.0 million interest payment due on the capital lease obligation, allowing us to defer payment of the interest due in December 2004, and waiving any default associated with the deferral. In connection with the transfer of the security in the Audrain projects to NRG FinCo Lenders, the Audrain entity will be liquidated resulting in the termination of the lease obligation and the note receivable.

Consolidated annual maturities and future minimum lease payments:

Annual maturities of long-term debt and capital leases for the years ending after December 31, 2004 are as follows:

	Total (In thousands)
2005	$ 509,454
2006	110,471
2007	92,609
2008	86,649
2009	79,683
Thereafter	2,928,330
Total	$3,807,196

Future minimum lease payments for capital leases included above at December 31, 2004 are as follows:

	(In thousands)
2005	$ 115,558
2006	96,039
2007	81,397
2008	73,418
2009	63,522
Thereafter	833,724
Total minimum obligations	1,263,658
Interest	719,707
Present value of minimum obligations	543,951
Current portion	69,920
Long-term obligations	$ 474,031

Assets related to our capital leases were revalued as of December 6, 2003, to $171.0 million and remained at $171.0 million with no accumulated amortization at December 31, 2004 and 2003, as the amounts have been recorded at recoverable values.

Note 19 — Capital Stock

Reorganized Capital Structure

In connection with the consummation of our reorganization, on December 5, 2003, all shares of our old common stock were canceled and 100,000,000 shares of new common stock of NRG Energy were distributed pursuant to such plan in accordance with Section 1145 of the bankruptcy code to the holders of certain classes of claims. We received no proceeds from such issuance. A certain number of shares of common stock were issued and placed in the Disputed Claims Reserve for distribution to holders of disputed claims as such claims are resolved or settled. See Item 3 — Legal Proceedings — Disputed Claims Reserve. In the event our disputed claims reserve is inadequate, it is possible we would have to issue additional shares of our common stock to satisfy such pre-petition claims or contribute additional cash proceeds. Our authorized capital stock consists of 500,000,000 shares of NRG Energy common stock and 10,000,000 shares of preferred stock. A total of 4,000,000 shares of our common stock are available for issuance under our long-term incentive plan. We have also filed with the Secretary of State of Delaware a Certificate of Designation of our 4% Convertible Perpetual Preferred Stock, or Preferred Stock, as more fully described in Note 20.

Repurchase of Common Stock

Upon emergence from chapter 11, investment partnerships managed by MatlinPatterson LLC owned approximately 21.5 million (21.5%) of our common shares. In December 2004, we used existing cash to repurchase 13 million shares of common stock from MatlinPatterson at a purchase price of $31.16 per share plus transaction costs of $0.2 million. In addition to a reduction in total shares of common stock outstanding by 13 million, the share repurchase resulted in (i) the reduction of MatlinPatterson's share ownership of NRG Energy to less than 10% from the prior 21.5%, (ii) termination of MatlinPatterson's registration rights, and (iii) resignation from our Board of Directors of three directors affiliated with MatlinPatterson. Our Board's Governance and Nominating Committee is in the process of identifying appropriate independent directors to fill the three vacancies.

Note 20 — Convertible Perpetual Preferred Stock

On December 27, 2004, we completed the sale of 420,000 shares of convertible perpetual preferred stock with a dividend coupon rate of 4%. The Preferred Stock has a liquidation preference of $1,000 per share of Preferred Stock. Holders of Preferred Stock are entitled to receive, when declared by our Board of Directors, cash dividends at the rate of 4% per annum, payable quarterly in arrears on March 15, June 15, September 15 and December 15 of each year, commencing on March 15, 2005. The Preferred Stock is convertible, at the option of the holder, at any time into shares of our common stock at an initial conversion price of $40.00 per share, which is equal to an approximate conversion rate of 25 shares of common stock per share of Preferred Stock, subject to specified adjustments. On or after December 20, 2009, we may redeem, subject to certain limitations, some or all of the Preferred Stock with cash at a redemption price equal to 100% of the liquidation preference, plus accumulated but unpaid dividends, including liquidated damages, if any, to the redemption date.

If we are subject to a fundamental change, as defined in the Certificate of Designation of the 4.0% Convertible Perpetual Preferred Stock, each holder of shares of Preferred Stock has the right, subject to certain limitations, to require us to purchase any or all of its shares of Preferred Stock at a purchase price equal to 100% of the liquidation preference, plus accumulated and unpaid dividends, including liquidated damages, if any, to the date of purchase. Final determination of a fundamental change must be approved by the Board of Directors.

Each holder of Preferred Stock has one vote for each share of Preferred Stock held by the holder on all matters voted upon by the holders of our common stock, as well as voting rights specifically provided for in our amended and restated certificate of incorporation or as otherwise from time to time required by law. In addition, whenever (1) dividends on the Preferred Stock or any other class or series of stock ranking on a parity with the Preferred Stock with respect to the payment of dividends are in arrears for dividend periods, whether or not consecutive, containing in the aggregate a number of days equivalent to six calendar quarters, or (2) we fail to pay the redemption price on the date shares of Preferred Stock are called for redemption or the purchase price on the purchase date for shares of Preferred Stock following a fundamental change, then, in each case, the holders of Preferred Stock (voting separately as a class with all other series of preferred stock upon which like voting rights have been conferred and are exercisable) are entitled to vote for the election of two of the authorized number of our directors at the next annual meeting of stockholders and at each subsequent meeting until all dividends accumulated or the redemption price on the Preferred Stock have been fully paid or set apart for payment. The term of office of all directors elected by holders of the Preferred Stock terminates immediately upon the termination of the rights of the holders of the Preferred Stock to vote for directors. Upon election of any additional directors, the number of directors that comprise our Board of Directors will be increased by the number of such additional directors.

The Preferred Stock is, with respect to dividend rights and rights upon liquidation, winding up or dissolution: junior to all of our existing and future debt obligations; junior to each other class or series of our capital stock other than (1) our common stock and any other class or series of our capital stock which provides that such class or series will rank junior to the Preferred Stock and (2) any other class or series of our capital stock the terms of which provide that such class or series will rank on a parity with the Preferred Stock; on a parity with any other class or series of our capital stock the terms of which provide that such class or series will rank on parity with the Preferred Stock; senior to our common stock and any other class or series of our capital stock the terms of which provide that such class or series will rank junior to the Preferred Stock; and effectively junior to all of our subsidiaries (1) existing and future liabilities and (2) capital stock held by others.

The proceeds of $406.4 million net of issuance costs of approximately $13.6 million, were used to redeem $375.0 million of Second Priority Notes on February 4, 2005.

On March 15, 2005, we made a $3.9 million dividend payment to our preferred shareholders of record as of March 1, 2005. This represents the first quarterly dividend payment we anticipate making to our preferred shareholders.

Note 21 — Stock-Based Compensation

Incentive Compensation Plans

Effective January 1, 2003, we adopted the fair value recognition provisions of SFAS Statement No. 123, *"Accounting for Stock-Based Compensation",* or SFAS No. 123. In accordance with SFAS Statement No. 148, *"Accounting for Stock-Based Compensation — Transition and Disclosure",* or SFAS No. 148, we adopted SFAS No. 123 under the prospective transition method which requires the application of the recognition provisions to all employee awards granted, modified, or settled after the beginning of the fiscal year in which the recognition provisions are first applied. As a result, we recognized compensation expense for any grants issued on or after January 1, 2003.

During 2004 and 2003, we recognized approximately $13.6 million and $0.4 million, respectively, of stock based compensation expense under the Long-Term Incentive Plan as follows:

	2004	2003
	(In thousands)	
Stock options	$ 6,353	$429
Restricted stock	5,184	—
Deferred stock units	2,055	—
Total	$13,592	$429

In December 2003, we adopted a new long-term incentive plan, or the Long-Term Incentive Plan, which is described below.

Long-Term Incentive Plan

The Long-Term Incentive Plan became effective upon our emergence from bankruptcy and was also approved by our stockholders on August 4, 2004. The Long-Term Incentive Plan provides for grants of stock options, stock appreciation rights, restricted stock, performance awards, deferred stock units and dividend equivalent rights. Our directors, officers and employees, as well as other individuals performing services for, or to whom an offer of employment has been extended by us, are eligible to receive grants under the Long-Term Incentive Plan. The purpose of the Long-Term Incentive Plan is to promote our long-term growth and profitability by providing these individuals with incentives to maximize stockholder value and otherwise contribute to our success and to enable us to attract, retain and reward the best available persons for positions of responsibility.

A total of 4,000,000 shares of our common stock are available for issuance under the Long-Term Incentive Plan, subject to adjustment in the event of a reorganization, recapitalization, stock split, reverse stock split, stock dividend, combination of shares, merger or similar change in our structure or our outstanding shares of common stock. There were 2,053,294 and 3,367,249 shares of common stock remaining available for grants of stock options under our Long-Term Incentive Plan as of December 31, 2004 and 2003, respectively.

The Compensation Committee of our Board of Directors administers the Long-Term Incentive Plan. If for any reason a Compensation Committee has not been appointed by our board to administer the Long-Term Incentive Plan, our Board of Directors has the authority to administer the plan and to take all actions under the plan.

The following is a summary of the material terms of the Long-Term Incentive Plan, but does not include all of the provisions of the plan.

Eligibility. Our directors, officers and employees, as well as other individuals performing services for, or to whom an offer of employment has been extended by, us are eligible to receive grants under the Long-Term Incentive Plan. In each case, the Compensation Committee selects the actual grantees.

Stock Options. Under the Long-Term Incentive Plan, the Compensation Committee may award grants of incentive stock options conforming to the requirements of Section 422 of the Internal Revenue Code, or non-qualified stock options. The Compensation Committee may not award to any one person in any calendar year options to purchase more than 1,000,000 shares of common stock. In addition, it may not award incentive stock options first exercisable in any calendar year whose underlying shares have a fair market value greater than $100,000, determined at the time of grant.

The Compensation Committee determines the exercise price of any options granted under the Long-Term Incentive Plan. However, the exercise price of any option may not be less than 100% of the fair market value of a share of our common stock on the date of grant, and the exercise price of an incentive stock option granted to a person who owns stock constituting more than 10% of the voting power of all classes of our stock may not be less than 110% of the fair market value of a share of our common stock on the date of grant.

Unless the Compensation Committee determines otherwise, the exercise price of any option may be paid in any of the following ways:

- in cash;
- by delivery of shares of common stock with a fair market value equal to the exercise price;
- by means of any cashless exercise procedure approved by the Compensation Committee; or
- by any combination of the foregoing.

The Compensation Committee determines the term of each option in its discretion. However, no term may exceed 10 years from the date of grant or, in the case of an incentive stock option granted to a person who owns stock constituting more than 10% of the voting power of all classes of our stock, five years from the date of grant. In addition, all options under the Long-Term Incentive Plan, whether or not then exercisable, generally cease vesting when a grantee ceases to be a director, officer or employee of, or to otherwise perform services for, us. Vested options generally expire 90 days after the date of cessation of service.

There are exceptions depending upon the circumstances of cessation. In the case of a grantee's death, all options become fully vested and remain exercisable for a period of one year after the date of death. In the case of a grantee's termination due to disability, vested options remain exercisable for a period of one year after the date of termination due to disability while his or her unvested options are forfeited. In the event of retirement, a grantee's vested options remain exercisable for a period of two years after the date of retirement while his or her unvested options are forfeited. Upon termination for cause, all options terminate immediately. Upon a change in control of NRG Energy, all of the options become fully vested and remain exercisable until the expiration date of the options. In addition, the Compensation Committee has the authority to grant options that become fully vested and exercisable automatically upon a change in control, whether or not the grantee is subsequently terminated.

Upon a reorganization, merger, consolidation or sale or other disposition of all or substantially all of our assets, the Compensation Committee may cancel any or all outstanding options under the Long-Term Incentive Plan in exchange for payment of an amount equal to the portion of the consideration that would have been payable to the grantees in the transaction if their options had been fully exercised immediately prior to the transaction, less the exercise price that would have been payable, or if the exercise price is greater than the consideration that would have been payable in the transaction, then for no consideration or payment.

Stock Appreciation Rights. Under the Long-Term Incentive Plan, the Compensation Committee may grant stock appreciation rights, or SARs, alone or in tandem with options, subject to terms and conditions as the Compensation Committee may specify. SARs granted in tandem with options become exercisable only when, to the extent and on the conditions that the related options are exercisable, and they expire at the same time the related options expire. The exercise of an option results in the immediate forfeiture of any related SAR to the extent the option is exercised, and the exercise of a SAR results in the immediate forfeiture of any related option to the extent the SAR is exercised.

Upon exercise of a SAR, the grantee receives an amount in cash, shares of our common stock or our other securities equal to the difference between the fair market value of a share of common stock on the date of exercise and the exercise price of the SAR or, in the case of a SAR granted in tandem with options, of the option to which the SAR relates, multiplied by the number of shares as to which the SAR is exercised. Unless otherwise provided in the grantee's grant agreement, each SAR is subject to the same termination and forfeiture provisions as the stock options described above.

Restricted Stock. Under the Long-Term Incentive Plan, the Compensation Committee may award restricted stock in the amounts that it determines in its discretion. Each grant of restricted stock is evidenced by a grant agreement, which specifies the applicable restrictions on such shares and the duration of the restrictions (which is generally at least six months). A grantee is required to pay us at least the aggregate par value of any shares of restricted stock within ten days of the grant, unless the shares are treasury shares. Unless otherwise provided in the grantee's grant agreement, each unit or share of restricted stock is subject to the same termination and forfeiture provisions as the stock options described above.

Performance Awards. Under the Long-Term Incentive Plan, the Compensation Committee may grant performance awards contingent upon achievement by the grantee, us or any of our divisions of specified performance criteria, such as return on equity, over a specified performance cycle, as determined by the Compensation Committee. Performance awards may include specific dollar-value target awards; performance units, the value of which is determined by the Compensation Committee at the time of issuance; and/or performance shares, the value of which is equal to the fair market value of common stock. The value of a performance award may be fixed or may fluctuate based on specified performance criteria. A performance award may be paid out in cash, shares of our common stock or our other securities.

A grantee must be a director, officer or employee of, or otherwise perform services for, us at the end of the performance cycle in order to be entitled to payment of a performance award issued in respect of such cycle, provided that unless otherwise provided in the grantee's grant agreement, each performance award is subject to the same termination and forfeiture provisions as the stock options described above.

Deferred Stock Units. Under the Long-Term Incentive Plan, the Compensation Committee may grant deferred stock units from time to time in its discretion. A deferred stock unit entitles the grantee to receive the fair market value of one share of common stock at the end of the deferral period, which is no less than one year. The payment of the value of deferred stock units may be made by us in shares of our common stock, cash or both. If a grantee ceases to be a director, officer or employee of, or otherwise perform services for, us upon his or her death prior to the end of the deferral period, the grantee receives payment of his or her deferred stock units which would have matured or been earned at the end of the deferral period as if the deferral period has ended as of the date of his or her death. In the event of a termination due to disability or retirement prior to the end of the deferral period, the grantee receives payment of his or her deferred stock units at the end of the deferral period. If a grantee ceases to be a director, officer or employee of, or otherwise perform services for, us for any other reason, his or her unvested deferred stock units are immediately forfeited. Upon a change in control in NRG Energy, a grantee receives payment of his or her deferred stock units as if the deferral period has ended as of the date of the change in control.

Dividend Equivalent Rights. Under the Long-Term Incentive Plan, the Compensation Committee may grant a dividend equivalent right entitling the grantee to receive amounts equal to all or any portion of the dividends that would be paid on shares of our common stock covered by an award if those shares had been delivered to the grantee pursuant to the award, subject to terms and conditions as the committee may specify.

Vesting, Withholding Taxes and Transferability of All Awards. The terms and conditions of each award made under the Long-Term Incentive Plan, including vesting requirements, is set forth consistent with the plan in a written agreement with the grantee. Except in limited circumstances and unless the Compensation Committee determines otherwise, no award under the Long-Term Incentive Plan may vest and become exercisable within six months of the date of grant.

Unless the Compensation Committee determines otherwise, a participant may elect to deliver shares of common stock, or to have us withhold shares of common stock otherwise issuable upon exercise of an option or a SAR or deliverable upon grant or vesting of restricted stock or the receipt of common stock, in order to satisfy our tax withholding obligations in connection with any exercise, grant or vesting.

Unless the Compensation Committee determines otherwise, no award made under the Long-Term Incentive Plan is transferable other than by will or the laws of descent and distribution, and each option, SAR or performance award may be exercised only by the grantee or his or her executor, administrator, guardian or legal representative, or by a family member of the grantee if he or she has acquired the option, SAR or performance award by gift or qualified domestic relations order.

Amendment and Termination of the Long-Term Incentive Plan. The Board of Directors or the Compensation Committee may amend or terminate the Long-Term Incentive Plan in its discretion, except that no amendment is effective without prior approval of our stockholders if approval is required by applicable law or regulations, including any NASDAQ or stock exchange listing requirements, if the amendment would remove a provision of the Long-Term Incentive Plan which, without giving effect to the amendment, is subject to shareholder approval or if the amendment would directly or indirectly increase the share limit of 4,000,000 shares. If not otherwise terminated, the Long-Term Incentive Plan terminates on the tenth anniversary of the effective date of our plan of reorganization, which was December 5, 2003.

In 2004, we issued stock options grants for a total of 330,000 shares of common stock under the Long-Term Incentive Plan. These options have a three-year graded vesting schedule and become exercisable through the year 2006 at an average exercise price of $21.46. Total compensation expense under all stock option grants is approximately $11.7 million. Compensation expense for the year ended December 31, 2004 and 2003 was approximately $6.4 million and $0.4 million, respectively. Compensation expense for the years ended December 31, 2005, December 31, 2006 and December 31, 2007 will be approximately $3.4 million, $1.4 million and $0.1 million, respectively. At December 31, 2004, 210,917 employee stock options were exercisable. The following table summarizes stock option transactions:

	Shares	Exercise Price Range Per Share	Weighted-Average Exercise Price
Outstanding at January 1, 2003	—	$ —	$ —
Granted	632,751	24.03	24.03
Exercised	—	—	—
Canceled or expired	—	—	—
Outstanding at December 6, 2003	632,751	$ 24.03	$24.03
Granted	—	—	—
Exercised	—	—	—
Canceled or expired	—	—	—
Outstanding at December 31, 2003	632,751	$ 24.03	$24.03
Granted	330,000	$19.90-$31.48	$21.46
Exercised	—	—	—
Canceled or expired	—	—	—
Outstanding at December 31, 2004	962,751	$19.90-$31.48	$23.15

The following table summarizes information about stock options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of exercise prices	Total Outstanding	Weighted-Average Remaining Life (In Years)	Weighted-Average Exercise Price	Total Exercisable	Weighted-Average Exercise Price
$19.90-$22.24	307,000	4.2	$20.92	—	NA
$24.03-$31.48	655,751	8.9	$24.20	210,917	$24.03

The fair value of the stock option grants were estimated on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	2004	2003
Dividends per year	—	—
Expected volatility	40.96%	35.70%
Risk-free interest rate	3.84%	4.24%
Expected life (years)	8.3	10

As of December 31, 2004, restricted stock units issued and outstanding under the Long-Term Incentive Plan totaled 880,994. These units fully vest in three years from the date of issuance. Total compensation expense attributable to the restricted stock grants is approximately $19 million. During the year ended

December 31, 2004, we issued 750,100 restricted stock units at fair values between \$19.90 and \$34.31, cancelled 40,500 restricted stock units at fair values between \$19.90 and \$25.90 and issued 1,255 shares of common stock, net of payroll taxes withheld, due to accelerated vesting on 2,000 restricted stock units at fair values between \$23.20 and \$27.43. Compensation expense for the year ended December 31, 2004 was approximately \$5.2 million. Compensation expense for the years ended December 31, 2005, December 31, 2006 and December 31, 2007 will be approximately \$6.1 million, \$6.5 million and \$1.2 million, respectively. The weighted-average fair value of our restricted stock units outstanding as of December 31, 2004 is \$21.59.

During 2004, deferred stock units issued under the Long-Term Incentive Plan totaled 100,961, and were issued solely to members of our Board of Directors. The fair values of the deferred stock units were between \$19.95 and \$21.05 per unit. These units are fully vested at the date of issuance. Total compensation expense attributable to the deferred stock grants is approximately \$2.1 million, and was recognized entirely in 2004. Elections were made at the time of issuance to immediately convert 6,798 deferred stock units to an equal number of shares of our common stock. As a result of our common stock repurchase in December 2004 and the termination of three members of our Board of Directors, 33,882 deferred stock units were converted into an equal number of shares of our common stock. The weighted-average fair value of our deferred stock units outstanding as of December 31, 2004 is \$20.31.

Note 22 — Earnings Per Share

Basic earnings per common share were computed by dividing net income less accumulated preferred stock dividends by the weighted average number of common stock shares outstanding. Shares issued during the year are weighted for the portion of the year that they were outstanding. Shares of common stock granted to our officers and employees are included in the computation only after the shares become fully vested. Diluted earnings per share is computed in a manner consistent with that of basic earnings per share while giving effect to all potentially dilutive common shares that were outstanding during the period. The dilutive effect of the potential exercise of outstanding options to purchase shares of common stock is calculated using the treasury stock method. The nonvested restricted stock units are not considered outstanding for purposes of computing basis earnings per share; however these units are included in the denominator for purposes of computing diluted earnings per share under the treasury method. The deferred stock units are considered outstanding upon grant date on a weighted average basis for computing basic earnings per share. The reconciliation of basic earnings per common share to diluted earnings per share is shown in the following table:

	Reorganized NRG	
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003
	(In thousands, except per share data)	
Basic earnings per share		
Numerator:		
Income from continuing operations	\$162,145	\$ 11,405
Preferred stock dividends	(549)	—
Net income available to common stockholders from continuing operations	161,596	11,405
Discontinued operations, net of tax	23,472	(380)
Net income available to common stockholders	\$185,068	\$ 11,025

	Reorganized NRG	
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003
	(In thousands, except per share data)	
Denominator:		
Weighted average number of common shares outstanding	99,616	100,000
Basis earnings per share:		
Income from continuing operations	$ 1.62	$ 0.11
Discontinued operations, net of tax	0.24	—
Net income	$ 1.86	$ 0.11
Diluted earnings per share		
Numerator		
Net income available to common stockholders from continuing operations	$161,596	$ 11,405
Preferred stock dividends	549	—
Income from continuing operations	162,145	11,405
Discontinued operations, net of tax	23,472	(380)
Net income available to common stockholders	$185,617	$ 11,025
Denominator:		
Weighted average number of common shares outstanding	99,616	100,000
Incremental shares attributable to the issuance of nonvested restricted stock units (treasury stock method)	345	60
Incremental shares attributable to the assumed conversion of deferred stock units (if converted method)	67	—
Incremental shares attributable to the assumed conversion of preferred stock (if-converted method)	343	—
Total dilutive shares	100,371	100,060
Diluted earnings per share:		
Income from continuing operations	$ 1.62	$ 0.11
Discontinued operations, net of tax	0.23	—
Net income	$ 1.85	$ 0.11

For the year ended December 31, 2004 and the period December 6, 2003 to December 31, 2003, options to purchase 962,751 and 632,751 shares of common stock at an average price of $23.15 and $24.03, respectively per share, were not included in the computation because the effect would be anti-dilutive.

Note 23 — Segment Reporting

In connection with our emergence from bankruptcy and the new management team, we determined that it was necessary to adjust our segment reporting disclosures to more closely align our disclosures with the realignment of our management team. Accordingly, we have expanded our domestic geographical disclosures and collapsed our international geographical disclosures related to our wholesale power generation segment. In addition, our other segments have been further refined. As a result of these changes, we have retroactively recast our prior period disclosures in a consistent manner.

We conduct the majority of our business within five reportable operating segments. All of our other operations are presented under the "All Other" category. Our reportable operating segments consist of Wholesale Power Generation — Northeast, Wholesale Power Generation — South Central, Wholesale Power Generation — West Coast, Wholesale Power Generation — Other North America and Wholesale Power Generation — Australia. These reportable segments are distinct components with separate operating results and management structures in place. Included in the All Other category are our Wholesale Power Generation — Other International operations, our Alternative Energy operations, our Non-Generation operations and an Other component which includes primarily our corporate charges (primarily interest expense) that have not been allocated to the reportable segments and the remainder of our operations which are not significant. We have presented this detail within the All Other category as we believe that this information is important to a full understanding of our business.

	Reorganized NRG Year Ended December 31, 2004									
	Wholesale Power Generation					All Other				
	Northeast	South Central	West Coast	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(In thousands)									
Operations										
Operating revenues	$1,251,153	$ 418,145	$ 2,469	$105,644	$ 181,065	$157,220	$65,872	$186,425	$ (6,569)	$2,361,424
Operating expenses	859,769	294,215	10,842	57,686	161,960	121,895	60,725	101,051	37,433	1,705,576
Depreciation and amortization	72,665	62,458	800	21,842	24,027	2,834	5,293	11,318	8,058	209,295
Corporate relocation charges	11	1	—	—	—	—	—	—	16,155	16,167
Reorganization items	180	976	—	142	—	—	—	513	(15,201)	(13,390)
Restructuring and impairment charges	247	2,909	—	26,505	—	—	—	—	15,000	44,661
Operating income/(loss)	318,281	57,586	(9,173)	(531)	(4,922)	32,491	(146)	73,543	(68,014)	399,115
Minority interest in earnings of consolidated subsidiaries	—	—	—	(1,029)	—	(16)	—	—	—	(1,045)
Equity in earnings (losses) of unconsolidated affiliates	—	—	74,375	17,455	17,524	50,921	(450)	—	—	159,825
Write downs and losses on sales of equity method investments	—	—	—	(11,172)	(1,268)	—	(3,830)	—	—	(16,270)
Other income (expense), net	4,324	474	434	1,831	4,845	5,966	1,893	1,811	4,987	26,565
Refinancing expenses	—	—	—	—	—	—	—	—	(71,569)	(71,569)
Interest expense	(791)	(8,710)	(3)	(47,970)	(11,189)	(10,769)	(445)	(8,419)	(181,068)	(269,364)
Income/(loss) from continuing operations before income taxes	321,814	49,350	65,633	(41,416)	4,990	78,593	(2,978)	66,935	(315,664)	227,257
Income tax expense/(benefit)	—	—	175	(9,961)	(4,610)	12,872	(1,224)	5,033	62,827	65,112
Income/(loss) from continuing operations	321,814	49,350	65,458	(31,455)	9,600	65,721	(1,754)	61,902	(378,491)	162,145
Income/(loss) on discontinued operations, net of income taxes	—	—	—	13,183	—	12,358	2,457	—	(4,526)	23,472
Net income/(loss)	$ 321,814	$ 49,350	$ 65,458	$(18,272)	$ 9,600	$ 78,079	$ 703	$ 61,902	$ (383,017)	$ 185,617
Balance Sheet										
Equity investments in affiliates	1,281	—	255,582	75,889	156,118	245,609	471	—	—	734,950
Total assets	$1,939,222	$1,076,578	$278,277	$781,658	$1,008,085	$905,034	$51,257	$504,926	$1,284,991	$7,830,028

Reorganized NRG
December 6, 2003 through December 31, 2003

	Wholesale Power Generation						All Other			
	Northeast	South Central	West Coast	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(In thousands)									
Operations										
Operating revenues	$ 69,191	$ 26,609	$ (268)	$ 5,377	$ 11,947	$ 13,082	$ 3,852	$ 10,013	$ (1,313)	$ 138,490
Operating expenses	53,016	19,491	119	2,790	10,385	10,798	3,424	8,053	(17)	108,059
Depreciation and amortization	4,604	2,561	58	1,639	1,475	212	324	497	438	11,808
Reorganization items	241	27	—	—	—	1	—	—	2,192	2,461
Operating income/(loss)	11,330	4,530	(445)	948	87	2,071	104	1,463	(3,926)	16,162
Minority interest in earnings of consolidated subsidiaries	—	—	—	(134)	—	—	—	—	—	(134)
Equity in earnings of unconsolidated affiliates	—	—	9,979	1,836	997	709	—	—	—	13,521
Other income (expense), net	(267)	99	—	163	274	905	151	77	(1,305)	97
Interest expense	(2,976)	(4,133)	—	(3,643)	(707)	(420)	(1)	(619)	(6,403)	(18,902)
Income/(loss) from continuing operations before income taxes	8,087	496	9,534	(830)	651	3,265	254	921	(11,634)	10,744
Income tax expense/(benefit)	—	—	—	357	(298)	1,045	—	45	(1,810)	(661)
Income/(loss) from continuing operations	8,087	496	9,534	(1,187)	949	2,220	254	876	(9,824)	11,405
Income/(loss) on discontinued operations, net of income taxes	—	—	—	(248)	—	(64)	(68)	—	—	(380)
Net income/(loss)	$ 8,087	$ 496	$ 9,534	$ (1,435)	$ 949	$ 2,156	$ 186	$ 876	$ (9,824)	$ 11,025
Balance Sheet										
Equity investments in affiliates	1,281	—	304,267	96,249	136,129	196,488	458	—	3,126	737,998
Total assets	$2,178,681	$1,128,404	$355,184	$2,052,100	$945,096	$1,058,072	$71,886	$334,658	$1,120,906	$9,244,987

	Predecessor Company January 1, 2003 through December 5, 2003									
	Wholesale Power Generation					All Other				
	Northeast	South Central	West Coast	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(In thousands)									
Operations										
Operating revenues	$ 861,452	$ 356,534	$ 23,956	$ 85,388	$ 151,494	$137,384	$ 60,871	$ 129,063	$ (7,755)	$1,798,387
Operating expenses	800,141	246,908	8,049	45,655	124,812	111,032	52,360	86,487	50,795	1,526,239
Depreciation and amortization	90,132	33,987	10,750	38,046	17,114	3,550	4,602	11,870	8,792	218,843
Reorganization items	1,813	28,769	—	41,717	—	—	—	—	125,526	197,825
Restructuring and impairment charges	232,170	1,574	—	17,994	5	133	1,067	26	(15,394)	237,575
Fresh start reporting adjustments	1,067,783	428,823	106,523	515,166	77,593	(10,676)	50,290	181,459	(6,535,597)	(4,118,636)
Legal settlement	—	—	—	4,000	—	—	(9,369)	—	468,000	462,631
Operating income/(loss)	(1,330,587)	(383,527)	(101,366)	(577,190)	(68,030)	33,345	(38,079)	(150,779)	5,890,123	3,273,910
Equity in earnings of unconsolidated affiliates	—	—	102,681	7,260	30,364	31,536	(940)	—	—	170,901
Write downs and losses on sales of equity method investments	—	—	—	12,125	(146,354)	3,389	(16,284)	—	—	(147,124)
Other income (expense), net	2,308	699	8	2,832	(934)	12,647	2,521	75	(947)	19,209
Interest expense	(69,663)	(73,968)	—	(92,031)	(4,176)	(7,896)	(153)	(9,805)	(72,197)	(329,889)
Income/(loss) from continuing operations before income taxes	(1,397,942)	(456,796)	1,323	(647,004)	(189,130)	73,021	(52,935)	(160,509)	5,816,979	2,987,007
Income tax expense/(benefit)	—	—	35,746	5,440	15,155	16,843	1,597	395	(37,247)	37,929
Income/(loss) from continuing operations	(1,397,942)	(456,796)	(34,423)	(652,444)	(204,285)	56,178	(54,532)	(160,904)	5,854,226	2,949,078
Income/(loss) on discontinued operations, net of income taxes	—	—	—	(279,639)	—	137,819	(25,123)	—	(15,690)	(182,633)
Net income/(loss)	$(1,397,942)	$(456,796)	$ (34,423)	$(932,083)	$(204,285)	$193,997	$(79,655)	$(160,904)	$ 5,838,536	$2,766,445

Predecessor Company
Year Ended December 31, 2002

	Wholesale Power Generation						All Other			
	Northeast	South Central	West Coast	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
					(In thousands)					
Operations										
Operating revenues	$964,196	$ 388,023	$30,796	$ 81,521	$ 170,761	$ 108,379	$ 69,030	$135,403	$ (9,816)	$ 1,938,293
Operating expenses	713,120	258,965	2,758	63,659	157,794	96,565	68,454	80,957	109,026	1,551,298
Depreciation and amortization	83,757	35,965	11,243	34,338	14,849	1,242	5,442	12,584	7,607	207,027
Restructuring and impairment charges	51,130	139,929	—	1,840,652	(16,265)	71,108	27,893	31	448,582	2,563,060
Operating income/(loss)	116,189	(46,836)	16,795	(1,857,128)	14,383	(60,536)	(32,759)	41,831	(575,031)	(2,383,092)
Equity in earnings of unconsolidated affiliates	—	(3,146)	24,012	23,287	15,680	33,617	(24,454)	—	—	68,996
Write downs and losses on sales of equity method investments	—	(48,375)	—	5,386	(129,190)	(12,751)	(15,542)	—	—	(200,472)
Other income (expense), net	5,822	922	—	1,359	(1,423)	10,680	1,503	(142)	(7,290)	11,431
Interest expense	(67,820)	(74,940)	(160)	(88,192)	(4,212)	(3,030)	(3,666)	(8,946)	(201,216)	(452,182)
Income/(loss) from continuing operations before income taxes	54,191	(172,375)	40,647	(1,915,288)	(104,762)	(32,020)	(74,918)	32,743	(783,537)	(2,955,319)
Income tax expense/(benefit)	—	—	5,843	8,848	(3,033)	14,982	(16,943)	11,654	(188,218)	(166,867)
Income/(loss) from continuing operations	54,191	(172,375)	34,804	(1,924,136)	(101,729)	(47,002)	(57,975)	21,089	(595,319)	(2,788,452)
Income/(loss) on discontinued operations, net of income taxes	—	—	—	(93,755)	—	(550,876)	(31,199)	—	—	(675,830)
Net income/(loss)	$ 54,191	$(172,375)	$34,804	$(2,017,891)	$(101,729)	$(597,878)	$(89,174)	$ 21,089	$(595,319)	$(3,464,282)

Note 24 — Income Taxes

The income tax provision (benefit) from continuing operations consists of the following amounts:

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
Current				
U.S.	$ (229)	$(1,513)	$ 2,231	$ 10,409
Foreign	17,118	1,184	15,630	17,160
	16,889	(329)	17,861	27,569
Deferred				
U.S.	56,747	59	3,292	(191,447)
Foreign	(8,524)	(391)	16,776	(2,989)
	48,223	(332)	20,068	(194,436)
Total income tax (benefit)	$65,112	$ (661)	$37,929	$(166,867)
Effective tax rate	28.7%	(6.2)%	1.3%	5.6%

The following represents the domestic and foreign income components of income (loss) from continuing operations before income tax expense (benefit):

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
U.S.	$139,007	$ 6,828	$3,103,117	$(2,818,537)
Foreign	88,250	3,916	(116,110)	(136,782)
	$227,257	$10,744	$2,987,007	$(2,955,319)

A reconciliation of the U.S. federal statutory rate to our effective rate from continuing operations for the year ended December 31, 2004, the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003 and for the year ended December 31, 2002 is as follows:

	Reorganized NRG				Predecessor Company			
	Year Ended December 31, 2004		For the Period December 6 - December 31, 2003		For the Period January 1 - December 5, 2003		Year Ended December 31, 2002	
	(Dollars in thousands)							
Income/(Loss) From Continuing Operations Before Income Taxes	$227,257		$10,744		$ 2,987,007		$(2,955,319)	
Tax at 35%	79,540	35.0%	3,760	35.0%	1,045,452	35.0%	(1,034,362)	35.0%
State taxes, (net of federal benefit)	6,455	2.9%	(1,834)	(17.1)%	254,112	8.5%	(167,405)	5.7%
Foreign operations	(22,294)	(9.8)%	(1,265)	(11.8)%	15,001	0.5%	(18,522)	0.6%
Fresh Start accounting adjustments	—	—			(1,383,334)	(46.3)%	—	
Tax credits	—	—						
Valuation allowance	—	—	(515)	(4.8)%	71,315	2.4%	1,006,540	(34.1)%
Change in tax rate	—	—			36,018	1.2%	—	
Permanent differences, reserves, other	1,411	0.6%	(807)	(7.5)%	(635)	—	46,882	(1.6)%
Income Tax Expense/(Benefit)	$ 65,112	28.7%	$ (661)	(6.2)%	$ 37,929	1.3%	$ (166,867)	5.6%

The temporary differences, which give rise to our deferred tax assets and liabilities consist of the following:

	Reorganized NRG	
	December 31, 2004	December 31, 2003
	(In thousands)	
Deferred tax liabilities:		
Discount/premium on notes	$ 20,191	$ 34,136
Emissions credits	115,150	147,811
Difference between book and tax basis of property	245,977	—
Other	—	988
Total deferred tax liabilities	381,318	$ 182,935
Deferred tax assets:		
Deferred compensation, accrued vacation and other reserves	54,240	46,684
Development costs	2,741	2,999
Net unrealized gains on mark to market transactions	9,914	20,634
Foreign net operating loss carryforwards	63,674	342,017
Differences between book and tax basis of contracts	161,792	175,224
Difference between book and tax basis of property	—	79,070
Nondepreciable Property	182,578	402,940
Intangibles amortization (other than goodwill)	13,358	13,053
Restructuring costs	60,159	20,468
U.S. net operating loss carry forwards	40,404	—
U.S. capital loss carryforwards	280,054	—
Investments in projects	82,691	159,370
Other	2,925	13,934
Total deferred tax assets (before valuation allowance)	954,530	1,276,393
Valuation allowance	(707,871)	(1,241,101)
Net deferred tax assets	246,659	35,292
Net deferred tax liability	$ 134,659	$ 147,643

The net deferred tax liability consists of:

	Reorganized NRG	
	December 31, 2004	December 31, 2003
	(In thousands)	
Current deferred tax liability (asset)	$ 334	$ (1,850)
Non-current deferred tax liability	134,325	149,493
Net deferred tax liability	$134,659	$147,643

We generated U.S. net operating loss carryforwards of $102.1 million for the year ended December 31, 2004, which will expire through 2024. Cumulative foreign net operating loss carryforwards of $200.6 million have no expiration date.

We believe that it is more likely than not that no benefit will be realized on a substantial portion of our deferred tax assets. This assessment included consideration of positive and negative evidence, including our current financial position and results of current operations, projected future taxable income, including projected operating and capital gains and our available tax planning strategies. Therefore, a valuation allowance of $707.9 million was recorded against the net deferred tax assets, including net operating loss carryforwards.

Under SOP 90-7, any future benefits from reducing a valuation allowance from preconfirmation deferred tax assets are required to be reported as a direct addition to paid in capital versus a benefit on our income statement. Consequently, our effective tax rate in post-bankruptcy emergence years will not benefit from the realization of our deferred tax assets, which were fully valued as of the date of our emergence from bankruptcy.

As of December 31, 2004, our management intends to indefinitely reinvest the earnings from our foreign operations. Accordingly, U.S. income taxes and foreign withholding taxes were not provided on the earnings from our foreign subsidiaries. As of December 31, 2004, no U.S. income tax benefit was provided on the cumulative losses from our foreign subsidiaries of $110.0 million. Our management is currently reviewing their reinvestment plan pursuant to the American Jobs Creation Act of 2004. This legislation provides for a low tax cost on earnings repatriated in 2005 and reinvested in a company's U.S. operations.

Note 25 — Related Party Transactions

Prior to our emergence from bankruptcy on December 5, 2003, NRG Energy was an indirect, wholly-owned subsidiary of Xcel Energy. Prior to December 5, 2003, we had entered into material transactions and agreements with Xcel Energy which are described below. Upon emergence from bankruptcy, we became an independent public company with no material affiliation or relationship to Xcel Energy. We have included amounts paid to or received from Xcel Energy during the year ended December 31, 2004 and for the period December 6, 2003 to December 31, 2003 only for comparative purposes, as these transactions are not considered related party transactions subsequent to December 5, 2003.

Stock Purchase Agreement

Upon emergence from chapter 11, investment partnerships managed by MatlinPatterson LLC owned approximately 21.5 million (21.5%) of our common shares. We used existing cash to repurchase 13 million shares of common stock from MatlinPatterson pursuant to a stock purchase agreement dated December 13, 2004 at a purchase price of $31.16 per share. In addition to a reduction in total shares of common stock outstanding by 13 million, the share repurchase resulted in (i) the reduction of MatlinPatterson's share ownership of NRG Energy to less than 10% from the prior 21.5%, (ii) termination of MatlinPatterson's registration rights, and (iii) resignation from our Board of Directors of three directors affiliated with MatlinPatterson. Our Board's Governance and Nominating Committee is in the process of identifying appropriate independent directors to fill the three vacancies.

Operating Agreements

We have two agreements with Xcel Energy for the purchase of thermal energy. Under the terms of the agreements, Xcel Energy charges us for certain costs (fuel, labor, plant maintenance, and auxiliary power) incurred by Xcel Energy to produce the thermal energy. We paid Xcel Energy $11.1 million, $1.1 million, $9.6 million and $8.2 million during the year ended December 31, 2004, the period December 6, 2003 to December 31, 2003, the period January 1, 2003 to December 5, 2003, and the year ended December 31, 2002, respectively, under these agreements. One of these agreements expires in 2006 and the other expires in 2010.

We have a renewable 10-year agreement with Xcel Energy, expiring on December 31, 2006, whereby Xcel Energy agreed to purchase refuse-derived fuel for use in certain of its boilers and we agree to pay Xcel Energy a burn incentive. Under this agreement, we received $1.4 million, $0, $1.4 million and $1.2 million from Xcel Energy and paid $3.7 million, $0.3 million, $3.9 million and $3.3 million to Xcel Energy during the year ended December 31, 2004, the period December 6, 2003 to December 31, 2003, the period January 1, 2003 to December 5, 2003 and the year ended December 31, 2002, respectively.

Administrative Services and Other Costs

We had an administrative services agreement in place with Xcel Energy. Under this agreement we reimbursed Xcel Energy for certain overhead and administrative costs, including benefits administration, engineering support, accounting and other shared services as requested by us. In addition, our employees participated in certain employee benefit plans of Xcel Energy as discussed in Note 26. We reimbursed Xcel Energy in the amounts of $7.3 million and $21.2 million during the period January 1, 2003 to December 5, 2003 and the year ended December 31, 2002, respectively, under this agreement. This agreement was terminated December 5, 2003.

Natural Gas Marketing and Trading Agreement

We had an agreement with e prime, a wholly-owned subsidiary of Xcel Energy, under which e prime provided natural gas marketing and trading from time to time at our request. We paid $19.2 million to e prime in 2002 related to these services. This agreement was terminated by e prime on December 12, 2002 and a termination charge of $0.3 million was paid in the period January 1, 2003 to December 5, 2003.

Note 26 — Benefit Plans and Other Postretirement Benefits

Reorganized NRG

Substantially all employees hired prior to December 5, 2003 were eligible to participate in our defined benefit pension plans. We have initiated a new NRG Energy noncontributory, defined benefit pension plan effective January 1, 2004, with credit for service from December 5, 2003. As of December 31, 2004, our accumulated benefit obligation was approximately $61.1 million. As of December 31, 2004, we had plan assets of $716,000.

In addition, we provide postretirement health and welfare benefits (health care and death benefits) for certain groups of our employees. Generally, these are groups that were acquired in recent years and for whom prior benefits are being continued (at least for a certain period of time or as required by union contracts). Cost sharing provisions vary by acquisition group and terms of any applicable collective bargaining agreements. As of December 31, 2004, our accumulated benefit obligation was approximately $45.5 million. We expect to contribute approximately $12.8 million to our NRG pension plan and our postretirement health and welfare plan in 2005.

NRG Flinders Retirement Plan

Employees of NRG Flinders, a wholly-owned subsidiary of NRG Energy, are members of the multiemployer Electricity Industry Superannuation Schemes, or EISS. Members of the EISS make contributions from their salary and the EISS Actuary makes an assessment of our liability. As a result of adopting Fresh Start we recorded a liability of approximately $13.8 million at December 5, 2003, to record our accumulated benefit obligation plan assets on the balance sheet at fair value. The balance sheet includes a liability related to the Flinders retirement plan of $8.5 million and $13.7 million at December 31, 2004 and 2003, respectively. NRG Flinders contributed $10.2 million, $0, $4.5 million and $5.8 million for the year ended December 31, 2004, the period December 6 through December 31, 2003, the period January 1 through December 5, 2003 and the year ended December 31, 2002, respectively.

The Superannuation Board is responsible for the investment of EISS assets. The assets may be invested in government securities, shares, property and a variety of other securities and the Board may appoint professional investment managers to invest all or part of the assets on its behalf.

NRG Pension and Postretirement Medical Plans

Components of Net Periodic Benefit Cost

The net annual periodic pension cost related to all of our plans, include the following components:

	Pension Benefits			
	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
Service cost benefits earned	$11,053	$ 800	$—	$—
Interest cost on benefit obligation	2,857	205	—	—
Expected return on plan assets	(44)	—	—	—
Curtailment gain	(750)	—	—	—
Net periodic benefit cost	$13,116	$1,005	$—	$—

	Other Benefits			
	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
Service cost benefits earned	$1,673	$130	$1,220	$1,206
Interest cost on benefit obligation	2,601	180	1,900	1,831
Amortization of prior service cost	—	—	(22)	(24)
Recognized actuarial (gain)/loss	—	—	178	5
Net periodic benefit cost	$4,274	$310	$3,276	$3,018

Reconciliation of Funded Status

A comparison of the pension benefit obligation and pension assets at December 31, 2004 and 2003 for all of our plans on a combined basis is as follows:

Reorganized NRG	Pension Benefits December 31, 2004	Pension Benefits December 31, 2003	Other Benefits December 31, 2004	Other Benefits December 31, 2003
	(In thousands)			
Benefit obligation at January 1	$ 48,955	$ —	$ 42,170	$ 31,584
Service cost	11,053	800	1,673	1,350
Interest cost	2,857	205	2,601	2,080
Plan initiation	—	47,950	—	—
Plan amendments	—	—	—	2,100
Plan curtailment	(750)	—	—	—
Actuarial (gain)/loss	2,073	—	6,004	5,396
Benefit payments	(254)	—	(993)	(340)
Benefit obligation at December 31	$ 63,934	$ 48,955	$ 51,455	$ 42,170
Fair value of plan assets at January 1	$ —	$ —	$ —	$ —
Actual return on plan assets	(30)	—	—	—
Employer contributions	1,000	—	993	340
Benefit payments	(254)	—	(993)	(340)
Fair value of plan assets at December 31	$ 716	$ —	$ —	$ —
Funded status at December 31 — excess of obligation over assets	$(63,218)	$(48,955)	$(51,455)	$(42,170)
Unrecognized net (gain) loss	2,147	—	5,997	—
Accrued benefit liability recognized on the consolidated balance sheet at December 31	$(61,071)	$(48,955)	$(45,458)	$(42,170)

Amounts recognized in the balance sheets consist of:

	Pension Benefits December 31, 2004	Pension Benefits December 31, 2003	Other Benefits December 31, 2004	Other Benefits December 31, 2003
	(In thousands)			
Accrued benefit cost	$(61,071)	$(48,955)	$(45,458)	$(42,170)
Unfunded accrued benefit obligation	—	—	—	—
Intangible assets	—	—	—	—
Accumulated other comprehensive income	—	—	—	—
Net amount recognized	$(61,071)	$(48,955)	$(45,458)	$(42,170)

	Pension Benefits	
	December 31, 2004	December 31, 2003
Projected benefit obligation	$63,934	$48,955
Accumulated benefit obligation	16,375	1,000
Fair value of plan assets	716	—

The following tables present the significant assumptions used:

	Pension Benefits		Other Benefits	
	2004	2003	2004	2003
Weighted-average assumptions used to determine benefit obligations at December 31				
Discount rate	5.75%	6.00%	5.75%	6.00%
Rate of compensation increase	4.00 - 4.50%	4.00 - 4.50%	—	—
Health care trend rate	—	—	9% grading to 5.5% in 2009	10% grading to 5.5% in 2009

	Pension Benefits		Other Benefits	
	2004	2003	2004	2003
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31				
Discount rate	6.00%	6.00%	6.00%	6.75%
Expected return on plan assets	8.00%	*	—	—
Rate of compensation increase	4.00 - 4.50%	4.00 - 4.50%	—	—
Health care trend rate	—	—	10% grading to 5.5% in 2009	11% grading to 5.5% in 2009

* We did not determine an expected return on plan assets for the NRG pension plan, as there were no plan assets at December 31, 2003.

Expected future benefit payments are:

	Pension Benefits	Post Retirement Medical Plans	
	Benefit Payments	Benefit Payments	Medicare Prescription Drug Reimbursements
		(In thousands)	
2005	$ 882	$ 1,328	$ —
2006	1,776	1,583	10
2007	2,486	1,861	25
2008	3,399	2,216	45
2009	4,817	2,552	75
2010-2014	42,491	17,438	815

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect (in thousands):

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total service and interest cost components	$ 558	$ (506)
Effect on postretirement benefit obligation	5,616	(5,410)

Defined Contribution Plans

Our employees have also been eligible to participate in defined contribution 401(K) plans. Our contributions to these plans were approximately $4.3 million, $3.8 million and $4.6 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Predecessor Company

Prior to December 5, 2003, all eligible employees participated in Xcel Energy's multiemployer noncontributory, defined benefit pension plan, which was formerly sponsored by NSP. We sponsored two defined benefit plans that were merged into Xcel Energy's plan as of June 30, 2002. Benefits were generally based on a combination of an employee's years of service and earnings. Some formulas also took into account Social Security benefits. Plan assets principally consisted of the common stock of public companies, corporate bonds and U.S. government securities.

Prior to December 5, 2003, certain former NRG Energy retirees were covered under the legacy Xcel Energy plan, which was terminated for non-bargaining employees retiring after 1998 and for bargaining employees retiring after 1999.

As a result of our emergence from bankruptcy on December 5, 2003, we are no longer owned by or affiliated with Xcel Energy and our employees are no longer participants of the Xcel Energy plans.

Participation in Xcel Energy, Inc. Pension Plan and Postretirement Medical Plan

We did not make contributions to the Xcel Energy pension plan and postretirement plan in 2002 or 2003. As of December 31, 2003, there are no liabilities recorded related to the Xcel Energy plans. The liabilities associated with these plans were settled as part of the NRG plan of reorganization. The net annual periodic cost (credit) related to our portion of the Xcel Energy pension plan and postretirement plans totaled $0.2 million and $(8.9) million for 2003 and 2002, respectively.

Prior to December 5, 2003, certain employees also participated in Xcel Energy's noncontributory defined benefit supplemental retirement income plan. This plan was for the benefit of certain qualifying executive personnel. Benefits for this unfunded plan were paid out of operating cash flows. The liability related to this plan was not material as of December 31, 2004 and 2003, respectively.

2003 Medicare Legislation

In May 2004, the Financial Accounting Standards Board, FASB, issued FASB Staff Position (FSP) No. 106-2, *"Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"* (FSP 106-2). FSP 106-2 provides guidance on accounting for the effects of the new Medicare Prescription Drug, Improvement, and Modernization Act of 2003 by employers whose prescription drug benefits are actuarially equivalent to the drug benefit under Medicare Part D. FSP 106-2 is effective as of the first interim period beginning after June 15, 2004. NRG Energy adopted FSP 106-2 in the third quarter of 2004 on a retroactive basis. Adoption of FSP 106-2 will reduce the annual non-cash postretirement health expense by approximately $0.2 million and reduce the accumulated postretirement benefit obligation by $2.2 million. The change in accumulated postretirement benefit obligation has been reflected as an actuarial gain and will be amortized in future periods.

Note 27 — Commitments and Contingencies

Operating Lease Commitments

We lease certain of our facilities and equipment under operating leases, some of which include escalation clauses, expiring on various dates through 2023. Rental expense under these operating leases was $11.3 million for the year ended December 31, 2004, $0.7 million for the period December 6, 2003 through December 31, 2003, $11.9 million for the period January 1, 2003 through December 5, 2003 and $13.2 million for the year ended December 31, 2002. Future minimum lease commitments under these leases for the years ending after December 31, 2004 are as follows:

	Total (In thousands)
2005	$ 16,176
2006	17,589
2007	14,794
2008	14,485
2009	14,337
Thereafter	62,943
Total	$140,324

In August 2004, we entered into a contract to purchase 1,540 aluminum railcars from Johnston America Corporation to be used for the transportation of low sulfur coal from Wyoming to NRG Energy's coal burning generating plants, including the Cajun Facilities. On February 18, 2005, we entered into a ten-year operating lease agreement with GE Railcar Services Corporation, or GE, for the lease of 1,500 railcars and delivery commenced in February 2005. We have assigned certain of our rights and obligations for 1,500 railcars under the purchase agreement with Johnston America to GE. Accordingly, the railcars which we lease from GE under the arrangement described above will be purchased by GE from Johnston America in lieu of our purchase of those railcars.

Coal Purchase and Transportation Commitments

In December 2004, we entered into a long-term coal transport agreement with the Burlington Northern and Santa Fe Railway Company and affiliates of American Commercial Lines LLC to deliver low sulfur coal to our Big Cajun II facility in New Roads, Louisiana beginning April 1, 2005. In December 2004, we also entered into coal purchase contracts extending through 2007. In March 2005, we entered into an agreement to purchase 23.75 million tons of coal over a period of four years and nine months from Buckskin Mining Company, or Buckskin. The coal will be sourced from Buckskin's mine in the Powder River Basin, Wyoming, and will be used primarily in NRG Energy's coal-burning generation plants in the South Central region. Future payments under these agreements for the years ending after December 31, 2004 are estimated as follows:

	Total (In thousands)
2005	$118,679
2006	85,682
2007	49,494
2008	37,189
2009	38,439
Thereafter	21,699
Total	$351,182

Capital Commitments

We anticipate funding our ongoing capital requirements through committed debt facilities, operating cash flows, and existing cash. Our capital expenditure program is subject to continuing review and modification. The timing and actual amount of expenditures may differ significantly based upon plant operating history, unexpected plant outages, and changes in the regulatory environment, and the availability of cash.

International

Two of our wholly-owned, indirect subsidiaries are severally responsible for the prorate payments of principal, interest and related costs incurred in connection with the financing of our equity investment in the unincorporated joint venture Gladstone Power Station. At December 31, 2004, we were obligated for the loan of AUD 108.4 million (approximately US $84.8 million) in principal. This loan is scheduled to be fully repaid on March 31, 2009.

NRG FinCo Settlement

In May 2001, our wholly-owned subsidiary, NRG FinCo, entered into a $2.0 billion revolving credit facility. The facility was established to finance the acquisition, development and construction of certain power generating plants located in the United States and to finance the acquisition of turbines for such facilities. The facility provided for borrowings of base rate loans and Eurocurrency loans and was secured by mortgages and security agreements in respect of the assets of the projects financed under the facility, pledges of the equity interests in the subsidiaries or affiliates of the borrower that own such projects, and by guaranties from each such subsidiary or affiliate. The NRG FinCo secured revolver was initially scheduled to mature on May 8, 2006; however, due to defaults hereunder by NRG FinCo and applicable guarantors, the lenders accelerated all outstanding obligations on November 6, 2002. As of our emergence from bankruptcy, $1.1 billion was outstanding under the facility, and there was an aggregate of approximately $58 million of accrued but unpaid interest and commitment fees. Of this, $842.0 million was allowed in unsecured claims under the NRG plan of reorganization, and was settled at the time of our emergence. The remaining balance will be satisfied when the NRG FinCo lenders exercise their perfected security interests in our Nelson, Audrain and Pike projects. During 2004, we sold our Nelson assets for approximately $19.5 million and certain assets of our Pike project for $17 million. The proceeds from these sales were paid to the lenders. As of December 31, 2004, we hold assets in our Audrain project, principally property, plant and equipment, and some remaining ancillary equipment in our Pike project of approximately $172 million and $5 million, respectively. Any proceeds from the sale of these assets are owed to the NRG FinCo lenders, accordingly there are liabilities reflected in other bankruptcy settlement for the same amount on our consolidated balance sheet. We are in the process of marketing for sale the Audrain project and the remaining Pike equipment on behalf of the NRG FinCo lenders. The NRG FinCo lenders have authority under their perfected security interest to accept or reject all offers. As a result, these entities are not reflected as discontinued operations. In accordance with a Term Sheet Agreement with the NRG FinCo lenders, we are accruing a monthly management fee and accruing for certain costs associated with the caretaking and marketing of these assets. We believe we have no additional risk of loss related to these entities.

Environmental Regulatory Matters

The construction and operation of power projects are subject to stringent environmental and safety protection and land use laws and regulation in the U.S. If such laws and regulations become more stringent, or new laws, interpretations or compliance policies apply and our facilities are not exempted from coverage, we could be required to make extensive modifications to further reduce potential environmental impacts. In general, the effect of future laws or regulations is expected to require the addition of pollution control equipment or the imposition of restrictions on our operations.

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at the facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by the party in connection with any releases or threatened releases. These laws impose strict (without fault) and joint and several liability. The cost of investigation, remediation or removal of any hazardous or toxic substances or petroleum products could be substantial. To date, we have not been named as a potentially responsible party with respect to any off-site waste disposal matter.

As part of acquiring existing generating assets, we have inherited certain environmental liabilities associated with regulatory compliance and site contamination. Often potential compliance implementation plans are changed, delayed or abandoned due to one or more of the following conditions: (a) extended negotiations with regulatory agencies, (b) a delay in promulgating rules critical to dictating the design of expensive control systems, (c) changes in governmental/regulatory personnel, (d) changes in governmental priorities or (e) selection of a less expensive compliance option than originally envisioned.

Northeast Region

Significant amounts of ash are landfilled at on and off-site locations. At Dunkirk, Huntley, Somerset and Indian River, ash is disposed at landfills owned and operated by the Company. The Company maintains financial assurance to cover costs associated with closure, post-closure care and monitoring activities. The Company has funded a trust in the amount of approximately $5.9 million to provide such financial assurance in New York and $6.7 million in Delaware. The Company must also maintain financial assurance for closing interim status "RCRA facilities" at the Devon, Middletown, Montville and Norwalk Harbor Generating Stations and has funded a trust in the amount of $1.5 million accordingly.

The Company inherited historical clean-up liabilities when it acquired the Somerset, Devon, Middletown, Montville, Norwalk Harbor, Arthur Kill and Astoria Generating Stations. During installation of a sound wall at Somerset Station in 2003, oil contaminated soil was encountered. The Company has delineated the general extent of contamination, determined it to be minimal, and has placed an activity use limitation on that section of the property. Site contamination liabilities arising under the Connecticut Transfer Act at the Devon, Middletown, Montville and Norwalk Harbor Stations have been identified. The Company has proposed a remedial action plan to be implemented over the next two to eight years (depending on the station) to address historical ash contamination at the facilities. The total estimated cost is not expected to exceed $1.5 million. Remedial obligations at the Arthur Kill generating station have been established in discussions between the Company and the NYSDEC and are estimated to cost between $1 million and $2 million. Remedial investigations continue at the Astoria generating station with long-term clean-up liability expected to be within the range of $2.5 million to $4.3 million. While installing groundwater-monitoring wells at Astoria to track our remediation of a historical fuel oil spill, the drilling contractor encountered deposits of coal tar in two borings. The Company reported the coal tar discovery to the NYSDEC in 2003 and delineated the extent of this contamination. The Company may also be required to remediate the coal tar contamination and/or record a deed restriction on the property if significant contamination is to remain in place.

We estimate that we will incur total environmental capital expenditures of $197.6 million during 2005 through 2010 for the facilities in New York, Connecticut, Delaware and Massachusetts. These expenditures will be primarily related to installation of particulate, SO_2 and NO_X controls, as well as installation of BTA under the Phase II 316(b) Rule.

Huntley Power LLC, Dunkirk Power LLC and Oswego Power LLC were issued Notices of Violation for opacity exceedances and entered into a Consent Order with NYSDEC, effective March 31, 2004. The Consent Order required the respondents to pay a civil penalty of $1.0 million which was paid in April 2004. The Order also establishes stipulated penalties (payable quarterly) for future violations of opacity requirements and a compliance schedule. The Company is currently in dispute with NYSDEC over the method of calculation for stipulated penalties. The Company has placed $867,400 in a reserve as of December 31, 2004, and does not believe that the final resolution will involve a material larger amount.

South Central Region

Liabilities associated with closure, post-closure care and monitoring of the ash ponds owned and operated on site at the Big Cajun II Generating Station are addressed through the use of a trust fund maintained by the Company in the amount of approximately $5.0 million. Annual payments are made to the fund in the amount of approximately $116,000.

We estimate approximately $149 million of capital expenditures will be incurred during the period 2005 through 2010 for out South Central facilities, primarily related to installation of particulate, SO_2 and NO_X controls, as well as studies for installation of BTA under the Phase II 316(b) Rule.

West Coast Region

The Asset Purchase Agreements for the Long Beach, El Segundo, Encina, and San Diego gas turbine generating facilities provide that SCE and SDG&E retain liability, and indemnify the Company, for existing soil and groundwater contamination that exceeds remedial thresholds in place at the time of closing. The Company and its business partner conducted Phase I and Phase II Environmental Site Assessments at each of these sites for purposes of identifying such existing contamination and provided the results to the sellers. SCE and SDG&E have agreed to address contamination identified by these studies and are undertaking corrective action at the Encina and San Diego gas turbine generating sites. Spills and releases of various substances have occurred at these sites since the Company established the historical baseline, all of which have been, or will be, completely remediated. An oil leak in 2002 from underground piping at the El Segundo Generating Station contaminated soils adjacent to and underneath the Unit 1 and 2 powerhouse. The Company excavated and disposed of contaminated soils that could be removed in accordance with existing laws. Following the

Company's formal request, the LARWQCB will allow contaminated soils to remain underneath the building foundation until the building is demolished.

NYISO Claims

In November 2002, NYISO notified us of claims related to New York City mitigation adjustments, general NYISO billing adjustments and other miscellaneous charges related to sales between November 2000 and October 2002. New York City mitigation adjustments totaled $11.4 million. The issue related to NYISO's concern that NRG would not have sufficient revenue to cover subsequent revisions to its energy market settlements. As of December 31, 2004, NYISO held $3.9 million in escrow for such future settlement revisions.

Legal Issues

California Wholesale Electricity Litigation and Related Investigations

We, West Coast Power, LLC, or WCP, WCP's four operating subsidiaries, Dynegy, Inc. and numerous other unrelated parties are the subject of numerous lawsuits arising based on events occurring in the California power market. Through our subsidiary, NRG West Coast Power LLC, we are a 50 percent beneficial owner with Dynegy of WCP, which owns, operates and markets the power of four California plants. Dynegy and its affiliates and subsidiaries are responsible for gas procurement and marketing and trading activities on behalf of WCP. The complaints primarily allege that the defendants engaged in unfair business practices, price fixing, antitrust violations, and other market "gaming" activities. Certain of these lawsuits, which seek unspecified treble damages and injunctive relief, were consolidated and made a part of a Multi-District Litigation proceeding before the U.S. District Court for the Middle District of California. Defendants filed dispositive motions in the fall of 2002 and in the first quarter of 2003, the judge granted motions to dismiss in certain of these cases based on federal preemption and the filed rate doctrine. On September 10, 2004, the U.S. Court of Appeals for the Ninth Circuit affirmed the District Court's dismissal. On November 5, 2004, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court and on February 22, 2005, the Supreme Court ordered the U.S. Solicitor General to submit its views on the petition.

Regarding the remaining cases, in December 2002, the U.S. District Court for the Southern District of California found that federal jurisdiction was absent and remanded the cases back to state court. On December 8, 2004, the U.S. Court of Appeals for the Ninth Circuit affirmed the District Court in most respects. On March 3, 2005, the Ninth Circuit denied a motion for rehearing. We anticipate that the cases will be remanded to state court in 2005 at which time the defendants will again raise file rate and federal preemption challenges. In the Northern California cases, on February 25, 2005, the Ninth Circuit approved the district court's decision to dismiss all of the defendants' cases.

In addition to the Multi-District Litigation discussed above, numerous other cases, including putative class actions, have been filed in state and federal court on behalf of business and residential electricity consumers which name us and/or WCP and/or certain subsidiaries of WCP, in addition to numerous other defendants. The complaints allege the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades, and violated California's antitrust law and unfair business practices law. The complaints seek restitution and disgorgement, civil fines, compensatory and punitive damages, attorneys' fees and declaratory and injunctive relief. Motion practice is proceeding in these cases and dispositive motions have been filed in several.

In certain of the above referenced cases, Dynegy is defending WCP and/or it subsidiaries pursuant to a limited indemnification agreement while in the others, Dynegy's counsel is representing it and WCP and/or it subsidiaries and with each party responsible for half of the costs.

FERC Proceedings

The FERC conducted an "Investigation of Potential Manipulation of Electric and Natural Gas Prices," which involved hundreds of parties, including WCP. In June 2001, FERC initiated proceedings related to California's demand for $8.9 billion in refunds from power sellers who allegedly inflated wholesale prices during the energy crisis. After two administrative law judge opinions and a March 26, 2003, FERC Order adopting in part and modifying in part the last of the two opinions, Dynegy, we and the WCP entities entered into extensive settlement negotiations with several governmental entities culminating in a comprehensive settlement which FERC approved on October 25, 2004 (the FERC Settlement).

As part of the FERC Settlement, WCP placed into escrow for distribution to California energy consumers a total of $22.5 million, which includes the $3 million settlement with FERC respecting trading techniques, announced on January 20, 2004. In addition, WCP agreed to forego: (1) past due receivables from the California Independent System Operator and the California Power Exchange related to the settlement period; and (2) natural gas cost recovery claims against the settling parties related to the settlement period. In exchange, the various California settling parties agreed to forego: (1) all claims relating to refunds or other monetary damages for sales of electricity during the settlement period; (2) claims alleging that WCP received unjust or unreasonable rates for the sale of electricity during the settlement period; and (3) FERC dismissed numerous investigations respecting market transactions. For a two year period following FERC's acceptance of the settlement agreement, WCP will retain an independent engineering company to perform semi-annual audits of the technical and economic basis, justification and rationale for outages that occurred at its California generating plants during the previous six month period, and to have the results of such audits provided to the FERC Office of Market Oversight and Investigation without any prior review by WCP.

West Coast Power previously established significant reserves on its balance sheet and will not incur any further loss associated with the FERC Settlement. We will pay no cash from corporate funds, nor will the FERC Settlement have any direct impact on our profit and loss statement.

There are a number of additional, related proceedings in which WCP subsidiaries are parties, which are either pending before FERC or on appeal from FERC to various U.S. Courts of Appeal. These cases involve, among other things, allegations of physical withholding, a FERC-established price mitigation plan determining maximum rates for wholesale power transactions in certain spot markets, and the enforceability of, and obligations under, various contracts with, among others, the California Independent System Operator and the State of California.

California Attorney General

The California Attorney General has undertaken an investigation entitled "In the Matter of the Investigation of Possibly Unlawful, Unfair, or Anti-Competitive Behavior Affecting Electricity Prices in California." As has Dynegy, we and subsidiaries of WCP have responded to interrogatories, document requests, and to requests for interviews.

NRG Bankruptcy Cap on California Claims

On November 21, 2003, in conjunction with confirmation of the NRG plan of reorganization, we reached an agreement with the Attorney General and the State of California, generally, whereby for purposes of distributions, if any, to be made to the State of California under the NRG plan of reorganization, the liquidated amount of any and all allowed claims shall not exceed $1.35 billion in the aggregate. The agreement neither affects our right to object to these claims on any and all grounds nor admits any liability whatsoever. We further agreed to waive any objection to the liquidation of these claims in a non-bankruptcy forum having proper jurisdiction.

We believe that we have valid defenses to the legal proceedings and investigations described above and intend to defend them vigorously. We cannot predict with certainty whether we incur any liability or estimate a range of possible loss, if any, that might be incurred in connection with these matters. However, an adverse result in one or more of these proceedings could have a material adverse effect on our financial condition, results of operations and cash flows.

New York Operating Reserve Markets

Consolidated Edison and others petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of FERC's refusal to order a re-determination of prices in the New York Independent System Operator, or NYISO, operating reserve markets for a two month period in 2000. On November 7, 2003, the court found that NYISO's method of pricing spinning reserves violated the NYISO tariff. On March 4, 2005, FERC issued an order stating that no refunds would be required for the tariff violation associated with the pricing of spinning reserves. In the order, FERC also stated that the exclusion of the Blenheim-Gilboa facility and western reserves from the non-spinning market was not a market flaw and NYISO was correct not to use its TEP authority to revise the prices in this market. Motions for rehearing of the Order must be filed by April 3, 2005. If the March 4, 2005 order is reversed and refunds are required, NRG entities which may be affected include NRG Power Marketing, Inc., Astoria Gas Turbine Power LLC and Arthur Kill Power LLC. Although non-NRG-related entities would share responsibility for payment of any such refunds, under the petitioners' theory the cumulative exposure to our above-listed entities could exceed $23 million.

Connecticut Congestion Charges

CL&P withheld approximately $30 million from amounts owed to NRG Power Marketing, Inc., or PMI under an October 29, 1999, contract and PMI counterclaimed. CL&P's motion for summary judgment, which PMI opposed, remains pending. We cannot estimate at this time the overall exposure for congestion charges for the full term of the contract, however, such amount has been fully reserved as a reduction to outstanding accounts receivable.

New York Environmental Settlement

In January 2002, the New York Department of Environmental Conservation, or NYSDEC, sued Niagara Mohawk Power Corporation, or NiMo, and us in federal court in New York asserting that projects undertaken at our Huntley and Dunkirk plants by NiMo, the former owner of the facilities, violated federal and state laws. On January 11, 2005, we reached an agreement to settle this matter whereby we will reduce levels of sulfur dioxide by over 86 percent and nitrogen oxide by over 80 percent in aggregate at the Huntley and Dunkirk plants. We are not subject to any penalty as a result of the settlement. Through the end of the decade, we expect that our ongoing compliance with the emissions limits set out in the settlement will be achieved through capital expenditures already planned. This includes our conversion to low sulfur western coal at the Huntley and Dunkirk plants that will be completed by Spring 2006. In a related case, on October 18, 2004, the parties reached a confidential settlement with respect to NiMo's obligation to indemnify us for any related compliance costs associated with resolution of the NYSDEC action.

Station Service Disputes

On October 2, 2000, NiMo commenced an action against us in New York state court seeking damages related to our alleged failure to pay retail tariff amounts for utility services at the Dunkirk Plant between June 1999 and September 2000. The parties agreed to consolidate this action with two other actions against the Huntley and Oswego Plants. On October 8, 2002, by Stipulation and Order, this action was stayed pending submission to FERC of some or all of the disputes in the action. The potential loss inclusive of amounts paid to NiMo and accrued is approximately $23.2 million. In a companion action at FERC, NiMo asserted the same claims and legal theories and on November 19, 2004, FERC denied NiMo's petition and ruled that the NRG facilities could net their service station obligations over a 30 calendar day period from the day NRG acquired the facilities. In addition, FERC ruled that neither NiMo nor the New York Public Service Commission could impose a retail delivery charge on the NRG facilities, because they are interconnected to transmission and not to distribution. NiMo filed a motion for rehearing.

On December 14, 1999, NRG Energy acquired certain generating facilities from CL&P. A dispute arose over station service power and delivery services provided to the facilities. On December 20, 2002, as a result of a petition filed at FERC by Northeast Utilities Services Company on behalf of itself and CL&P, FERC issued an Order finding that at times when NRG Energy is not able to self-supply its station power needs, there is a sale of station power from a third-party and retail charges apply. In August 2003, the parties agreed to submit the dispute to binding arbitration, however, the parties have yet to agree on a description of the dispute and on the appointment of a neutral arbitrator. The potential loss inclusive of amounts paid to CL&P and accrued could exceed $6 million.

U.S. Environmental Protection Agency

On January 27, 2004, our subsidiaries, Louisiana Generating, LLC and Big Cajun II, received a request under Section 114 of the federal Clean Air Act from USEPA Region 6 seeking information primarily relating to physical changes made at Big Cajun II. Louisiana Generating, LLC and Big Cajun II submitted several responses to the USEPA in response to follow-up requests. On February 15, 2005, Louisiana Generating, LLC received a Notice of Violation alleging violations of the New Source Review provisions of the Clean Air Act at Big Cajun 2 Units 1 and 2 from 1998 through the Notice of Violation date. Given the preliminary stage of this NOV process, the Company cannot predict the outcome of this matter at this time, but it is actively engaged with USEPA to address the issues.

TermoRio Litigation

TermoRio was a green field cogeneration project located in the state of Rio de Janeiro, Brazil. Based on the project's failure to meet certain key milestones, we exercised our rights under the project agreements to sell our debt and equity interests in the project to our partner Petroleo Brasileiro S.A.–Petrobras, or Petrobras. On March 8, 2003, the arbitral tribunal decided most, but not all, of the issues in our favor and awarded us approximately US$80 million. On June 4 2004, NRG Energy commenced a lawsuit in federal court seeking to enforce the arbitration award. On February 16, 2005, a conditional settlement agreement was signed with our former partner Petrobras, whereby Petrobras is obligated to pay us US$70.825 million. Such payment was received by us at a closing held on February 25, 2005. The settlement is being accounted for as a gain contingency. As of December 31, 2004, we had a note receivable from Petrobras of $57.3 million related to the arbitral award. The amounts paid in excess of the $57.3 million will be recognized in earnings in the first quarter of 2005. In addition to the settlement figure, we have the right to continue to seek recovery of US$12.3 million in a related dispute with a third-party.

Itiquira Energetica, S.A.

Our Brazilian project company, Itiquira Energetica S.A., the owner of a 156 MW hydro project in Brazil, is in arbitration with the former EPC contractor for the project, Inepar Industria e Construcoes, or Inepar. The dispute was commenced by Itiquira in September of 2002 and pertains to certain matters arising under the former EPC contract. Itiquira seeks $40 million and asserts that Inepar breached the contract. Inepar seeks $10 million and alleges that Itiquira breached the contract. Final written arguments were submitted on January 28, 2005, to the court of arbitration and a decision is expected during the first quarter of 2005.

CFTC Trading Litigation

On July 1, 2004, the CFTC filed a civil complaint against us in Minnesota federal district court, alleging false reporting of natural gas trades from August 2001 to May 2002, and seeking an injunction against future violations of the Commodity Exchange Act On November 17, 2004, a Bankruptcy Court hearing was held on the CFTC's motion to reinstate its expunged bankruptcy claim, and on our motion to enforce the provisions of the NRG plan of reorganization thereby precluding the CFTC from continuing its federal court action. Although the bankruptcy court has not yet ruled on those motions, on December 6, 2004, a federal magistrate judge issued a report and recommendation that our motion to dismiss be granted. That motion to dismiss was granted by the federal district court in Minnesota on March 16, 2005. The Bankruptcy Court has yet to schedule for a hearing or rule on the CFTC's pending motion to reinstate its expunged claim.

Additional Litigation

In addition to the foregoing, we are parties to other litigation or legal proceedings arising in the ordinary course of business. In management's opinion, the disposition of these ordinary course matters will not materially adversely affect our financial condition, results of operations or cash flows.

The Company believes that it has valid defenses to the legal proceedings and investigations described above and intends to defend them vigorously. However, litigation is inherently subject to many uncertainties. There can be no assurance that additional litigation will not be filed against the Company or its subsidiaries in the future asserting similar or different legal theories and seeking similar or different types of damages and relief. Unless specified above, the Company is unable to predict the outcome these legal proceedings and investigations may have or reasonably estimate the scope or amount of any associated costs and potential liabilities. An unfavorable outcome in one or more of these proceedings could have a material impact on the Company's consolidated financial position, results of operations or cash flows. The Company also has indemnity rights for some of these proceedings to reimburse the Company for certain legal expenses and to offset certain amounts deemed to be owed in the event of an unfavorable litigation outcome.

Pursuant to the requirements of Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies," and related guidance, we record reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable. Management has assessed each of these matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought and the probability of success. Management's judgment may, as a result of facts arising prior to resolution of these matters or other factors, prove inaccurate and investors should be aware that such judgment is made subject to the known uncertainty of litigation.

Disputed Claims Reserve

As part of the NRG plan of reorganization, we have funded a disputed claims reserve for the satisfaction of certain general unsecured claims that were disputed claims as of the effective date of the plan. Under the terms of the plan, to the extent such claims are resolved now that we have emerged from bankruptcy, the claimants will be paid from the reserve on the same basis as if they had been paid out in the bankruptcy. That means that their allowed claims will be reduced to the same recovery percentage as other creditors would have received and will be paid in pro rata distributions of cash and common stock. We believe we have funded the disputed claims reserve at a sufficient level to settle the remaining unresolved proofs of claim we received during the bankruptcy proceedings. However, to the extent the aggregate amount of these payouts of disputed claims ultimately exceeds the amount of the funded claims reserve, we are obligated to provide additional cash, notes and common stock to the claimants. We will continue to monitor our obligation as the disputed claims are settled. If excess funds remain in the disputed claims reserve after payment of all obligations, such amounts will be reallocated to the creditor pool. We have contributed common stock and cash to an escrow agent to complete the distribution and settlement process. Since we have surrendered control over the common stock and cash provided to the disputed claims reserve, we recognized the issuance of the common stock as of December 6, 2003 and removed the cash amounts from our balance sheet. Similarly, we have removed the obligations relevant to the claims from our balance sheet when the common stock was issued and cash contributed.

Note 28 — Cash Flow Information

Detail of supplemental disclosures of cash flow and non-cash investing and financing information was:

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
Interest paid (net of amount capitalized)	$294,697	$86,874	$182,355	$331,679
Income taxes paid/(refunds)	34,352	1,726	27,064	(17,406)
Non-cash investing and financing activities:				
Capitalized lease obligation incurred	223	—	—	—
Investment in WCP by contributing fixed assets	1,590	—	—	—
Reduction to fixed assets due to liquidated damages	14,543	—	—	—

Note 29 — Guarantees and Other Contingent Liabilities

In November 2002, the FASB issued FASB Interpretation No. 45, *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."* In connection with the adoption of Fresh Start, all outstanding guarantees were considered new; accordingly, we applied the provisions of FIN 45 to all of the guarantees.

We and our subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchase and sale agreements, commodity sale and purchase agreements, joint venture agreements, operations and maintenance agreements, service agreements, settlement agreements, and other types of contractual agreements with vendors and other third parties. These contracts generally indemnify the counter-party for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements. In many cases, our maximum potential liability cannot be estimated, since some of the underlying agreements contain no limits on potential liability.

The material guarantees, within the scope of FIN 45, are as follows:

- **Standby letters of credit and surety bonds** — At December 31, 2004, we and our consolidated subsidiaries were contingently obligated for approximately $173.2 million under standby letters of credit. Most of these letters of credit are issued in support of our obligations to perform under commodity agreements, financing or other arrangements. These letters of credit expire within one year of issuance, and it is typical for us to renew many of them on similar terms.

  As of December 31, 2004, standby letters of credit in amounts totaling approximately $157.1 million were issued under our $350.0 million corporate funded letter of credit facility, which is reflected in our financial statements. This amount includes a $33.3 million letter of credit issued to the benefit of Xcel to cover potential obligations from which Xcel was not released when we ceased to be an affiliate of theirs, though our maximum exposure under this arrangement is indeterminate. In addition, $2.4 million was issued to support performance obligations of an unconsolidated affiliate of ours.

Approximately $16.1 million in letters of credit were issued separately and are not supported by collateral. Of the uncollateralized letters of credit, approximately $4.8 million was issued to support the obligations of an unconsolidated affiliate of ours. We were also contingently obligated for $4.5 million under surety bonds to support our prepayment, completion, license, tax or performance bonding requirements. Most of the bonds are supported by collateral, which is reflected in our financial statements. All of the bonds expire within one year; however, we expect to renew many of these bonds on a rolling twelve-month basis.

- **Asset purchases and divestitures** — In the normal course of business, we may be asked to provide certain assurances to the counter-parties of our asset sale and purchase agreements. Such assurances may take the form of a guarantee issued by us on behalf of a directly or indirectly held majority-owned subsidiary. Due to the inter-company nature of such arrangements (NRG Energy is essentially guaranteeing its own performance) and the nature of the guarantee being provided (usually the typical representations and warrantees that are provided in any asset sales agreement), it is not our policy to recognize the value of such an obligation in our consolidated financial statements. Most of these guarantees provide an explicit cap on our maximum liability, as well as an expiration period, exclusive of breach of representations and warranties. At December 31, 2004, our maximum known exposure under asset sales guarantees was $73.5 million. On February 18, 2005 we executed a guarantee to the benefit of our counter-party under the railcar lease described in Items 7 — Contractual Obligations and Commercial Commitments. This guarantee covers NRG PMI payment and performance obligations under the relevant lease documents, and is of indeterminate exposure.

- **Commercial sales arrangements** — In connection with the purchase and sale of fuel, emission credits and power generation products to and from third parties with respect to the operation of some of our generation facilities in the U.S., we may be required to guarantee a portion of the obligations of certain of our subsidiaries. These obligations may include liquidated damages payments or other unscheduled payments. As of December 31, 2004, we estimate the maximum liability for this category of guarantee was $57.6 million. We have subsequently issued additional guarantees of the performance of NRG PMI, with a maximum liability of $0.3 million. These guarantees terminate on May 31, 2005 and December 31, 2005.

- **Other types of guarantees** — We have issued guarantees of obligations our subsidiaries may incur in provision of environmental site remediation, funding reserve accounts, payment of debt obligations, and performance under operating and maintenance agreements. Maximum quantifiable liability under the environmental guarantees is approximately $65.9 million, most of which is a guarantee for plant removal and site remediation obligations at our Flinders facilities. The maximum quantifiable exposure under the operational guarantees is $25.8 million, primarily related to our role as operator at the Gladstone power plant. In addition, we have a maximum liability exposure of $0.6 million under a tax indemnity guarantee to a third party, reserve funding guarantee exposure of $1.0 million and third-party debt guarantee exposure of $0.8 million.

The following table outlines the scheduled expiration of our guarantees, indemnity and other contingent liability obligations, to the extent the maximum liabilities can be quantified and scheduled.

Guarantee Type	Amount of Guarantee Liabilities Expiration per Period as of December 31, 2004 (in thousands)				
	Total Amounts Committed	Short-term	1-3 Years	4-5 Years	After 5 Years or Indeterminate
Funded standby letters of credit	$157,144	$157,144	$ —	$ —	$ —
Unfunded standby letters of credit	16,103	16,103	—	—	—
Surety bonds	4,467	4,467	—	—	—
Asset sales guarantee obligations	73,515	1,000	250	12,500	59,765
Commodity sales guarantee obligations	57,600	24,100	—	—	33,500
Other guarantees	94,126	—	778	—	93,348
Total guarantees	$402,955	$202,814	$1,028	$12,500	$186,613

The material indemnities, within the scope of FIN 45, are as follows:

- **Asset purchases and divestitures** — The purchase and sale agreements which govern our asset or share investments and divestitures customarily contain indemnifications of the transaction to third parties. The contracts indemnify the parties for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party, or as a result of a change in tax laws. These obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or quantify at the time of the transaction. In several cases, the contract limits the liability of the indemnitor. For those indemnities in which liability is capped, the exposure ranges from $1.0 million up to $50.0 million. We have no reason to believe that we currently have any material liability relating to such routine indemnification obligations.

- **Other indemnities** — Other indemnifications we have provided cover operational, tax, litigation and breaches of representations, warranties and covenants. We have also indemnified, on a routine basis in the ordinary course of business, consultants or other vendors who have provided services to us. Our maximum potential exposure under these indemnifications can range from a specified dollar amount to an unlimited amount, depending on the nature of the transaction. Total maximum potential exposure under these indemnifications is not estimable due to uncertainty as to whether claims will be made or how they will be resolved. We do not have any reason to believe that we will be required to make any material payments under these indemnity provisions.

Because many of the guarantees and indemnities we issue to third parties do not limit the amount or duration of our obligations to perform under them, there exists a risk that we may have obligations in excess of the amounts described above. For those guarantees and indemnities that do not limit our liability exposure, we may not be able to estimate what our liability would be, until a claim was made for payment or performance, due to the contingent nature of these contracts.

Note 30 — Sales to Significant Customers

Reorganized NRG

For the year ended December 31, 2004, we derived approximately 49.8% of our total revenues from majority-owned operations from four customers. NYISO accounted for 28.5%, ISO New England accounted for 9.1%, Vattenfall Europe (Germany) accounted for 5.4% and National Electricity Market Management Co. Ltd (Australia) accounted for 6.8%. For the period December 6, 2003 through December 31, 2003, we derived approximately 39.0% of our total revenues from majority-owned operations from two customers: NYISO accounted for 26.5% and ISO New England accounted for 12.5%. Revenues from NYISO and ISO New England are included in our Northeast segment.

Predecessor Company

For the period from January 1, 2003 through December 5, 2003 and for the year ended December 31, 2002, sales to one customer, NYISO, accounted for 33.4% and 26.0%, respectively, of our total revenues from majority-owned operations.

Note 31 — Jointly Owned Plants

Big Cajun II Unit 3

On March 31, 2000, we acquired a 58% interest in the Big Cajun II, Unit 3 generation plant. Entergy Gulf States owns the remaining 42%. Big Cajun II, Unit 3 is operated and maintained by Louisiana Generating pursuant to a joint ownership participation and operating agreement. Under this agreement, Louisiana Generating and Entergy Gulf States are each entitled to their ownership percentage of the hourly net electrical output of Big Cajun II, Unit 3. All fixed costs are shared in proportion to the ownership interests. All variable costs are incurred in proportion to the energy delivered to the owners. Our income statement includes its share of all fixed and variable costs of operating the unit.

Reorganized NRG

Our 58% share of the property, plant and equipment and construction in progress as revalued to fair value upon the adoption of the fresh start provisions of SOP 90-7 at December 31, 2004 and 2003 was $182.8 million and $183.2 million, respectively, and the corresponding accumulated depreciation and amortization was $11.5 million and $0.5 million, respectively.

Keystone and Conemaugh

In June 2001, we completed the acquisition of an approximately 3.7% interest in both the Keystone and Conemaugh coal-fired generating facilities. The Keystone and Conemaugh facilities are located near Pittsburgh, Pennsylvania and are jointly owned by a consortium of energy companies. We purchased our interest from Conectiv, Inc. Keystone and Conemaugh are operated by GPU Generation, Inc., which sold its assets and operating responsibilities to Sithe Energies. Keystone and Conemaugh both consist of two operational coal-fired steam power units with a combined net output of 1,700 MW, four diesel units with a combined net output of 11 MW and an on-site landfill. The units are operated pursuant to a joint ownership participation and operating agreement. Under this agreement each joint owner is entitled to its ownership ratio of the net available output of the facility. All fixed costs are shared in proportion to the ownership interests. All variable costs are incurred in proportion to the energy delivered to the owners. Our income statement includes our share of all fixed and variable costs of operating the facilities.

Reorganized NRG

Our 3.70% and 3.72% share of the Keystone and Conemaugh facilities original cost included in property, plant and equipment and construction in progress at December 31, 2004 was $58.6 million and $70.7 million, respectively. The corresponding accumulated depreciation and amortization at December 31, 2004 for Keystone and Conemaugh was $3.2 million and $3.9 million, respectively.

Our 3.70% and 3.72% share of the Keystone and Conemaugh facilities property, plant and equipment and construction in progress as revalued to fair value upon the adoption of the fresh start provisions of SOP 90-7 at December 31, 2003 was $57.9 million and $69.7 million, respectively. The corresponding accumulated depreciation and amortization at December 31, 2003 for Keystone and Conemaugh was $0.2 million and $0.3 million, respectively.

Note 32 — Unaudited Quarterly Financial Data

Summarized quarterly unaudited financial data is as follows:

	Reorganized NRG					
	Quarter Ended 2004					Period Ended December 6 - December 31, 2003
	March 31	June 30	September 30	December 31	Total Year	
	(In thousands)					
Operating Revenues	$600,265	$573,623	$606,663	$580,873	$2,361,424	$138,490
Operating Income	119,748	116,791	78,998	83,578	399,115	16,162
Income From Continuing Operations	31,446	69,400	43,330	17,969	162,145	11,405
Income/(Loss) on Discontinued Operations net of Income Taxes	(1,211)	13,624	10,891	168	23,472	(380)
Net Income	$ 30,235	$ 83,024	$ 54,221	$ 18,137	$ 185,617	$ 11,025
Weighted Average Number of Common Shares Outstanding — Basic	100,018	100,080	100,101	98,456	99,616	100,000
Income From Continuing Operations per Weighted Average Common Share — Basic	$ 0.31	$ 0.69	$ 0.43	$ 0.18	$ 1.62	$ 0.11
Income/(Loss) From Discontinued Operations per Weighted Average Common Share — Basic	(0.01)	0.14	0.11	0.00	0.24	—
Net Income per Weighted Average Common Share — Basic	$ 0.30	$ 0.83	$ 0.54	$ 0.18	$ 1.86	$ 0.11
Weighted Average Number of Common Shares Outstanding — Diluted	100,018	100,478	100,616	98,978	100,371	100,060
Income From Continuing Operations per Weighted Average Common Share — Diluted	$ 0.31	$ 0.69	$ 0.43	$ 0.18	$ 1.62	$ 0.11
Income From Discontinued Operations per Weighted Average Common Share — Diluted	(0.01)	0.14	0.11	—	0.23	—
Net Income per Weighted Average Common Share — Diluted	$ 0.30	$ 0.83	$ 0.54	$ 0.18	$ 1.85	$ 0.11

	Predecessor Company				
	Quarter Ended 2003			Period Ended October 1 - December 5, 2003	Total through December 5, 2003
	March 31	June 30	September 30		
	(In thousands)				
Operating Revenues	$ 494,947	$ 441,538	$ 570,701	$ 291,201	$1,798,387
Operating Income/(Loss)	(11,958)	(318,595)	(327,565)	3,932,028	3,273,910
Income/(Loss) From Continuing Operations	(173,136)	(508,518)	(284,544)	3,915,276	2,949,078
Income/(Loss) on Discontinued Operations net of Income Taxes	160,504	(99,883)	(250)	(243,004)	(182,633)
Net Income/(Loss)	(12,632)	(608,401)	(284,794)	3,672,272	2,766,445

Note 33 — Condensed Consolidating Financial Information

On December 17, 2003 and January 28, 2004, we issued $1.2 billion and $475.0 million, respectively, of 8% Second Priority Senior Secured Notes due on December 15, 2013 (the Notes). These notes are guaranteed by each of our current and future wholly-owned domestic subsidiaries, or Guarantor Subsidiaries. Each of the following Guarantor Subsidiaries fully and unconditionally guarantee the Notes.

Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Berrians I Gas Turbine Power LLC
Big Cajun II Unit 4 LLC
Capistrano Cogeneration Company
Chickahominy River Energy Corp.
Commonwealth Atlantic Power LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company
El Segundo Power II LLC
Hanover Energy Company
Huntley Power LLC
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Louisiana Generating LLC
Middletown Power LLC
Montville Power LLC
NEO California Power LLC
NEO Chester-Gen LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Landfill Gas Holdings Inc.
NEO Power Services Inc.
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Arthur Kill Operations Inc.
NRG Asia-Pacific, Ltd.
NRG Astoria Gas Turbine Operations, Inc.
NRG Bayou Cove LLC
NRG Cabrillo Power Operations Inc.
NRG Cadillac Operations Inc.
NRG California Peaker Operations LLC
NRG Connecticut Affiliate Services Inc.
NRG Devon Operations Inc.
NRG Dunkirk Operations Inc.
NRG El Segundo Operations Inc.
NRG Huntley Operations Inc.
NRG International LLC
NRG Kaufman LLC
NRG Mesquite LLC
NRG MidAtlantic Affiliate Services Inc.
NRG MidAtlantic Generating LLC
NRG Middletown Operations Inc.
NRG Montville Operations Inc.
NRG New Jersey Energy Sales LLC
NRG New Roads Holdings LLC
NRG North Central Operations Inc.
NRG Northeast Affiliate Services Inc.
NRG Northeast Generating LLC
NRG Norwalk Harbor Operations Inc.
NRG Operating Services, Inc.
NRG Oswego Harbor Power Operations Inc.
NRG Power Marketing Inc.
NRG Rocky Road LLC
NRG Saguaro Operations Inc.
NRG South Central Affiliate Services Inc.
NRG South Central Generating LLC
NRG South Central Operations Inc.
NRG West Coast LLC
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Saguaro Power LLC
Somerset Operations Inc.
Somerset Power LLC
Vienna Operations Inc.
Vienna Power LLC

The non-guarantor subsidiaries, or Non-Guarantor Subsidiaries, include all of our foreign subsidiaries and certain domestic subsidiaries. We conduct much of our business through and derive much of our income from our subsidiaries. Therefore, our ability to make required payments with respect to our indebtedness and other obligations depends on the financial results and condition of our subsidiaries and our ability to receive funds from our subsidiaries. Except for NRG Bayou Cove, LLC, which is subject to certain restrictions under our Peaker financing agreements, there are no restrictions on the ability of any of the Guarantor Subsidiaries to transfer funds to us. In addition, there may be restrictions for certain Non-Guarantor Subsidiaries.

The following condensed consolidating financial information presents the financial information of NRG Energy, the Guarantor Subsidiaries and the Non-Guarantor Subsidiaries in accordance with Rule 3-10 under the Securities and Exchange Commission's Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the Guarantor Subsidiaries or Non-Guarantor Subsidiaries operated as independent entities.

In this presentation, NRG Energy consists of parent company operations. Guarantor Subsidiaries and Non-Guarantor Subsidiaries of NRG Energy are reported on an equity basis. For companies acquired, the fair values of the assets and liabilities acquired have been presented on a "push-down" accounting basis.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2004
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$1,721,575	$595,708	$ 50,713	$ (6,572)	$2,361,424
Operating Costs and Expenses					
Cost of majority-owned operations	1,060,115	409,551	31,242	(6,572)	1,494,336
Depreciation and amortization	133,123	62,989	13,183	—	209,295
General, administrative and development	117,462	32,156	61,600	22	211,240
Other charges (credits)					
Corporate relocation charges	2	(1)	16,166	—	16,167
Reorganization items	1,838	(25)	(15,203)	—	(13,390)
Restructuring and impairment charges	3,156	26,505	15,000	—	44,661
Total operating costs and expenses	1,315,696	531,175	121,988	(6,550)	1,962,309
Operating Income/(Loss)	405,879	64,533	(71,275)	(22)	399,115
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(1,045)	—	—	(1,045)
Equity in earnings of consolidated subsidiaries	88,671	1	293,364	(382,036)	—
Equity in earnings of unconsolidated affiliates	91,602	68,869	(646)	—	159,825
Write downs and losses on sales of equity method investments	(15,737)	(1,271)	738	—	(16,270)
Other income, net	7,380	34,574	5,028	(20,417)	26,565
Refinancing expenses	—	—	(71,569)	—	(71,569)
Interest expense	51	(107,516)	(182,525)	20,626	(269,364)
Total other income/(expense)	171,967	(6,388)	44,390	(381,827)	(171,858)
Income/(Loss) From Continuing Operations Before Income Taxes	577,846	58,145	(26,885)	(381,849)	227,257
Income Tax Expense/(Benefit)	238,042	44,107	(217,028)	(9)	65,112
Income/(Loss) From Continuing Operations	339,804	14,038	190,143	(381,840)	162,145
Income/(Loss) on Discontinued Operations, net of Income Taxes	3,013	24,985	(4,526)	—	23,472
Net income	$ 342,817	$ 39,023	$ 185,617	$(381,840)	$ 185,617

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEETS
December 31, 2004
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
		ASSETS			
Current Assets					
Cash and cash equivalents	$ 155,795	$ 242,523	$ 711,727	$ —	$1,110,045
Restricted cash	3,720	109,104	—	—	112,824
Accounts receivable-trade, net	182,340	82,757	7,004	—	272,101
Current portion of notes receivable and other investments — affiliates	—	(2,986)	5,482	(2,496)	—
Current portion of notes receivable and other investments	—	85,147	300	—	85,447
Taxes receivable	1	(5,498)	42,981	—	37,484
Inventory	216,932	29,617	1,461	—	248,010
Derivative instruments valuation	79,759	—	—	—	79,759
Prepayments and other current assets	103,891	25,740	42,893	(2,916)	169,608
Current deferred income tax	—	—	—	—	—
Current assets — discontinued operations	(88)	3,098	—	—	3,010
Total current assets	742,350	569,502	811,848	(5,412)	2,118,288
Property, Plant and Equipment					
In service	2,359,090	1,163,986	41,582	—	3,564,658
Under construction	24,481	(10,044)	2,796	196	17,429
Total property, plant and equipment	2,383,571	1,153,942	44,378	196	3,582,087
Less accumulated depreciation	(140,013)	(53,925)	(13,598)	—	(207,536)
Net property, plant and equipment	2,243,558	1,100,017	30,780	196	3,374,551
Other Assets					
Investment in subsidiaries	776,922	—	3,916,352	(4,693,274)	—
Equity investments in affiliates	327,425	407,054	471	—	734,950
Notes receivable and other investments, less current portion — affiliates	407,165	363,462	—	(642,581)	128,046
Notes receivable and other investments, less current portion	1,533	673,966	977	—	676,476
Decommissioning fund investments	4,954	—	—	—	4,954
Deferred income taxes	—	—	—	—	—
Intangible assets, net	256,392	37,958	—	—	294,350
Debt issuance costs, net	—	247	48,238	—	48,485
Derivative instruments valuation	1,468	34,926	5,393	—	41,787
Funded letter of credit	—	—	350,000	—	350,000
Other assets	31,452	21,596	5,093	—	58,141
Total other assets	1,807,311	1,539,209	4,326,524	(5,335,855)	2,337,189
Total Assets	$4,793,219	$3,208,728	$5,169,152	$(5,341,071)	$7,830,028

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEETS — (Continued)
December 31, 2004
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
LIABILITIES AND STOCK HOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt	$ 16	$ 98,877	$ 415,855	$ (2,496)	$ 512,252
Accounts payable — trade	69,919	91,119	5,093	—	166,131
Accounts payable — affiliate	333,514	(129,041)	(199,799)	917	5,591
Accrued taxes	—	—	—	—	—
Accrued property, sales and other taxes	1,841	8,188	1,105	—	11,134
Accrued salaries, benefits and related costs	15,723	6,493	12,990	—	35,206
Accrued interest	435	6,000	7,538	(2,916)	11,057
Derivative instruments valuation	16,772	—	—	—	16,772
Current deferred income taxes	260	92	(18)	—	334
Other bankruptcy settlement	—	175,576	—	—	175,576
Other current liabilities	106,863	17,245	28,418	—	152,526
Current liabilities — discontinued operations	—	1,362	—	—	1,362
Total current liabilities	545,343	275,911	271,182	(4,495)	1,087,941
Other Liabilities					
Long-term debt	202	1,768,068	2,128,177	(642,581)	3,253,866
Deferred income taxes	(32,379)	130,972	35,732	—	134,325
Postretirement and other benefit obligations	98,439	8,987	8,957	—	116,383
Derivative instruments valuation	172	132,209	16,064	—	148,445
Other long-term obligations	341,960	30,883	16,876	—	389,719
Non-current liabilities — discontinued operations	—	1,081	—	—	1,081
Total non-current liabilities	408,394	2,072,200	2,205,806	(642,581)	4,043,819
Total liabilities	953,737	2,348,111	2,476,988	(647,076)	5,131,760
Minority interest	—	6,104	—	—	6,104
Commitments and Contingencies					
Stockholders' Equity	3,839,482	854,513	2,692,164	(4,693,995)	2,692,164
Total Liabilities and Stockholders' Equity	$4,793,219	$3,208,728	$5,169,152	$(5,341,071)	$7,830,028

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2004
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income/(loss)	$342,817	$ 39,023	$ 185,617	$(381,840)	$ 185,617
Adjustments to reconcile net income/(loss) to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	(52,620)	(37,953)	(523)	90,034	(1,062)
Depreciation and amortization	133,123	68,314	13,183	—	214,620
Reserve for note and interest receivable	7,165	4,572	—	—	11,737
Amortization of deferred financing costs and debt discount/(premium)	—	20,532	7,127	—	27,659
Write-off of deferred financing costs due to refinancings	—	—	42,137	—	42,137
Write downs and losses on sales of equity method investments	15,737	1,271	(738)	—	16,270
Deferred income taxes and investment tax credits	25,958	(8,138)	118,258	(78,840)	57,238
Unrealized (gains)/losses on derivatives	(70,301)	(9,254)	5,763	—	(73,792)
Minority interest	—	1,046	—	—	1,046
Amortization of power contracts and emission credits	14,210	37,442	—	—	51,652
Amortization of unearned equity compensation	2,173	328	11,091	—	13,592
Restructuring and impairment charges	3,156	26,505	15,000	—	44,661
(Gain)/loss on sale of discontinued operations	(1,922)	(25,119)	4,622	—	(22,419)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions					
Accounts receivable	(61,929)	4,103	6,355	—	(51,471)
Xcel Energy settlement receivable	—	—	640,000	—	640,000
Inventory	(52,079)	(3,307)	(227)	—	(55,613)
Prepayments and other current assets	(22,938)	34,180	35,570	1,960	48,772
Accounts payable	8,273	19,430	(31,809)	11,011	6,905
Accrued expenses	27,037	1,569	(31,640)	(18,129)	(21,163)
Creditor pool obligation payments	—	—	(540,000)	—	(540,000)
Other current liabilities	36,082	(43,286)	14,446	—	7,242
Other assets and liabilities	16,650	(9,184)	32,899	—	40,365
Net Cash Provided (Used) by Operating Activities	370,592	122,074	527,131	(375,804)	643,993
Cash Flows from Investing Activities					
Proceeds from sale of discontinued operations	1,941	250,735	—	—	252,676
Proceeds from sale of investments	21,000	26,693	3,000	—	50,693
Decrease/(increase) in restricted cash	717	(27,160)	—	—	(26,443)
Decrease/(increase) in notes receivable	(22,976)	14,937	25,775	7,373	25,109
Capital expenditures	(77,026)	(27,691)	(9,447)	(196)	(114,360)
Investments in projects	4,313	(15,840)	8,537	—	(2,990)
Distributions/(investments) in subsidiaries	—	—	82,163	(82,163)	—
Net Cash Provided (Used) by Investing Activities	(72,031)	221,674	110,028	(74,986)	184,685
Cash Flows from Financing Activities					
Net borrowings under line of credit agreement					
Proceeds from issuance of preferred shares	—	—	406,359	—	406,359
Payment for treasury stock	—	—	(405,312)	—	(405,312)
Capital contributions from parent	9,850	32,987	—	(42,837)	—
Dividends and return of investment to NRG Energy, Inc.	(407,000)	(10,000)	—	417,000	—
Proceeds from issuance of long-term debt	—	(6,336)	1,303,500	35,507	1,332,671
Deferred debt issuance costs	—	(247)	(25,259)	—	(25,506)
Funded letter of credit	—	—	(100,000)	—	(100,000)
Principal payments on long-term debt	(41,125)	(291,941)	(1,200,000)	41,120	(1,491,946)
Net Cash Provided (Used) by Financing Activities	(438,275)	(275,537)	(20,712)	450,790	(283,734)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	3,007	—	—	3,007
Change in Cash from Discontinued Operations	—	10,871	—	—	10,871
Net Increase (Decrease) in Cash and Cash Equivalents	(139,714)	82,089	616,447	—	558,822
Cash and Cash Equivalents at Beginning of Period	295,509	160,434	95,280	—	551,223
Cash and Cash Equivalents at End of Period	$155,795	$ 242,523	$ 711,727	$ —	$ 1,110,045

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Period December 6, 2003 Through December 31, 2003
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$94,455	$40,741	$ 3,353	$ (59)	$138,490
Operating Costs and Expenses					
Cost of majority-owned operations	64,519	28,734	2,347	(59)	95,541
Depreciation and amortization	7,118	3,931	759	—	11,808
General, administrative and development	7,165	2,803	2,550	—	12,518
Other charges (credits)					
Reorganization items	269	—	2,192	—	2,461
Total operating costs and expenses	79,071	35,468	7,848	(59)	122,328
Operating Income/(Loss)	15,384	5,273	(4,495)	—	16,162
Other Income/(Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(134)	—	—	(134)
Equity in earnings of consolidated subsidiaries	3,266	143	16,482	(19,891)	—
Equity in earnings of unconsolidated affiliates	11,007	1,463	1,051	—	13,521
Other income, net	43	(23)	114	(37)	97
Interest expense	(6,417)	(4,719)	(7,803)	37	(18,902)
Total other income/(expense)	7,899	(3,270)	9,844	(19,891)	(5,418)
Income/(Loss) From Continuing Operations Before Income Taxes	23,283	2,003	5,349	(19,891)	10,744
Income Tax Expense/(Benefit)	3,653	1,362	(5,676)	—	(661)
Income/(Loss) From Continuing Operations	19,630	641	11,025	(19,891)	11,405
Income/(Loss) on Discontinued Operations, net of Income Taxes	(4)	(376)	—	—	(380)
Net Income	$19,626	$ 265	$11,025	$(19,891)	$ 11,025

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEETS
December 31, 2003
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
		ASSETS			
Current Assets					
Cash and cash equivalents	$ 295,509	$ 160,434	$ 95,280	$ —	$ 551,223
Restricted cash	4,298	111,769	—	—	116,067
Accounts receivable-trade, net	120,411	68,151	13,359	—	201,921
Xcel Energy settlement receivable	—	—	640,000	—	640,000
Current portion of notes receivable and other investments — affiliates	—	—	31,170	(30,970)	200
Current portion of notes receivable and other investments	—	64,854	287	—	65,141
Inventory	164,853	28,839	1,234	—	194,926
Derivative instruments valuation	772	—	—	—	772
Prepayments and other current assets	86,656	58,175	78,263	(956)	222,138
Current deferred income tax	—	2,998	—	(1,148)	1,850
Current assets — discontinued operations	15	119,586	—	—	119,601
Total current assets	672,514	614,806	859,593	(33,074)	2,113,839
Property, Plant and Equipment					
In service	2,288,280	1,562,048	35,137	—	3,885,465
Under construction	20,600	118,433	138	—	139,171
Total property, plant and equipment	2,308,880	1,680,481	35,275	—	4,024,636
Less accumulated depreciation	(7,118)	(3,923)	(759)	—	(11,800)
Net property, plant and equipment	2,301,762	1,676,558	34,516	—	4,012,836
Other Assets					
Investment in subsidiaries	626,979	—	4,090,996	(4,717,975)	—
Equity investments in affiliates	403,606	322,279	12,113	—	737,998
Notes receivable and other investments, less current portion — affiliates	389,257	120,733	—	(379,838)	130,152
Notes receivable and other investments, less current portion	5,678	684,489	1,277	—	691,444
Decommissioning fund investments	4,809	—	—	—	4,809
Intangible assets, net	411,540	20,821	—	—	432,361
Debt issuance costs, net	—	—	74,337	—	74,337
Derivative instruments valuation	—	59,907	—	—	59,907
Non current deferred income tax	58,586	—	—	(58,586)	—
Funded letter of credit	—	—	250,000	—	250,000
Other assets	31,220	26,407	56,504	—	114,131
Non-current assets — discontinued operations	—	623,173	—	—	623,173
Total other assets	1,931,675	1,857,809	4,485,227	(5,156,399)	3,118,312
Total Assets	$4,905,951	$4,149,173	$5,379,336	$(5,189,473)	$9,244,987

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEETS — (Continued)
December 31, 2003
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
		LIABILITIES AND STOCKHOLDERS' EQUITY			
Current Liabilities					
Current portion of long-term debt	$ 30,121	$ 790,078	$ 12,000	$ (30,970)	$ 801,229
Short-term debt	—	19,019	—	—	19,019
Accounts payable — trade	39,369	104,888	14,389	—	158,646
Accounts payable — affiliate	333,722	(221,168)	(102,094)	(7,368)	3,092
Accrued taxes	—	—	(74)	16,169	16,095
Accrued property, sales and other taxes	7,211	13,156	1,934	—	22,301
Accrued salaries, benefits and related costs	9,294	8,949	1,087	—	19,330
Accrued interest	2,557	2,880	4,501	(956)	8,982
Derivative instruments valuation	429	—	—	—	429
Creditor pool obligation	—	—	540,000	—	540,000
Other bankruptcy settlement	—	220,000	—	—	220,000
Current deferred income taxes	509	—	—	(509)	—
Other current liabilities	70,251	13,639	18,971	—	102,861
Current liabilities — discontinued operations	31	114,166	—	—	114,197
Total current liabilities	493,494	1,065,607	490,714	(23,634)	2,026,181
Other Liabilities					
Long-term debt	10,999	1,333,931	2,446,690	(463,838)	3,327,782
Deferred income taxes	—	152,392	(22,514)	19,615	149,493
Postretirement and other benefit obligations	80,720	13,425	11,801	—	105,946
Derivative instruments valuation	—	153,503	—	—	153,503
Other long-term obligations	399,353	66,196	15,389	—	480,938
Non-current liabilities — discontinued operations	—	558,884	—	—	558,884
Total non-current liabilities	491,072	2,278,331	2,451,366	(444,223)	4,776,546
Total liabilities	984,566	3,343,938	2,942,080	(467,857)	6,802,727
Minority interest	—	5,004	—	—	5,004
Commitments and Contingencies					
Stockholders' Equity	3,921,385	800,231	2,437,256	(4,721,616)	2,437,256
Total Liabilities and Stockholders' Equity	$4,905,951	$4,149,173	$5,379,336	$(5,189,473)	$9,244,987

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Period December 6, 2003 Through December 31, 2003
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income/(loss)	$ 19,626	$ 265	$ 11,025	$ (19,891)	$ 11,025
Adjustments to reconcile net income/(loss) to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	1,764	(1,894)	(17,532)	19,891	2,229
Depreciation and amortization	8,255	4,027	759	—	13,041
Amortization of deferred financing costs	—	64	453	—	517
Amortization of debt discount/(premium)	182	1,504	39	—	1,725
Deferred income taxes and investment tax credits	(487)	(212)	(4,117)	1,554	(3,262)
Current tax expense — non cash contribution from members	4,125	(2,901)	—	(1,224)	—
Unrealized (gains)/losses on derivatives	(126)	4,960	(1,060)	—	3,774
Minority interest	134	70	—	—	204
Amortization of power contracts and emission credits	(16,401)	2,970	—	—	(13,431)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions					
Accounts receivable, net	12,769	5,040	221	—	18,030
Inventory	3,073	8,041	(60)	—	11,054
Prepayments and other current assets	1,783	1,755	(13,079)	37	(9,504)
Accounts payable	(31,810)	8,672	(17,789)	—	(40,927)
Accounts payable-affiliates	(1,697)	(165)	2,694	—	832
Accrued income taxes	—	—	(877)	(330)	(1,207)
Accrued property and sales taxes	(5,258)	622	46	—	(4,590)
Accrued salaries, benefits, and related costs	2,135	3,511	(2,496)	—	3,150
Accrued interest	(42,350)	(26,140)	4,501	(37)	(64,026)
Other current liabilities	(10,814)	5,635	(505,688)	—	(510,867)
Other assets and liabilities	(162)	(6,911)	431	—	(6,642)
Net Cash Provided (Used) by Operating Activities	(55,259)	8,913	(542,529)	—	(588,875)
Cash Flows from Investing Activities					
Investments in subsidiaries	—	—	(1,530,536)	1,530,536	—
Decrease/(increase) in restricted cash	343,725	31,547	—	—	375,272
Decrease/(increase) in notes receivable	1,501	(11,118)	(1,170)	11,969	1,182
Capital expenditures	(2,977)	(7,583)	—	—	(10,560)
Investments in projects	(2,522)	—	—	—	(2,522)
Net Cash Provided (Used) by Investing Activities	339,727	12,846	(1,531,706)	1,542,505	363,372
Cash Flows from Financing Activities					
Capital contributions from parent	1,530,536	—	—	(1,530,536)	—
Proceeds from issuance of long-term debt	—	—	2,450,000	—	2,450,000
Deferred debt issuance costs	—	(5)	(74,790)	—	(74,795)
Funded letter of credit	—	—	(250,000)	—	(250,000)
Principal payments on long-term debt	(1,713,871)	(6,092)	—	(11,969)	(1,731,932)
Net Cash Provided (Used) by Financing Activities	(183,335)	(6,097)	2,125,210	(1,542,505)	393,273
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(13,562)	—	—	(13,562)
Change in Cash from Discontinued Operations	—	1,033	—	—	1,033
Net Increase in Cash and Cash Equivalents	101,133	3,133	50,975	—	155,241
Cash and Cash Equivalents at Beginning of Period	194,376	157,301	44,305	—	395,982
Cash and Cash Equivalents at End of Period	$ 295,509	$160,434	$ 95,280	$ —	$ 551,223

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Period January 1, 2003 Through December 5, 2003
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$1,230,291	$522,467	$ 47,054	$ (1,425)	$1,798,387
Operating Costs and Expenses					
Cost of majority-owned operations	991,237	332,858	33,239	(1,425)	1,355,909
Depreciation and amortization	130,491	74,845	13,507	—	218,843
General, administrative and development	65,751	28,815	75,764	—	170,330
Other charges (credits)					
Reorganization items	30,582	16,644	150,599	—	197,825
Restructuring and impairment charges	247,560	(121,604)	111,619	—	237,575
Fresh start reporting adjustments	—	—	(6,570,912)	2,452,276	(4,118,636)
Fresh start reporting adjustments — subsidiaries	—	—	2,452,276	(2,452,276)	—
Legal settlement	(9,369)	4,000	468,000	—	462,631
Total operating costs and expenses	1,456,252	335,558	(3,265,908)	(1,425)	(1,475,523)
Operating Income/(Loss)	(225,961)	186,909	3,312,962	—	3,273,910
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	104,905	—	(18,356)	(86,549)	—
Equity in earnings of unconsolidated affiliates	107,254	64,850	(1,203)	—	170,901
Write downs and losses on sales of equity method investments	(16,285)	(125,945)	(4,894)	—	(147,124)
Other income, net	5,087	30,470	(15,429)	(919)	19,209
Interest expense	(135,837)	(83,135)	(111,836)	919	(329,889)
Total other income/(expense)	65,124	(113,760)	(151,718)	(86,549)	(286,903)
Income/(Loss) From Continuing Operations Before Income Taxes	(160,837)	73,149	3,161,244	(86,549)	2,987,007
Income Tax Expense/(Benefit)	(107,292)	(10,791)	156,012	—	37,929
Income/(Loss) From Continuing Operations	(53,545)	83,940	3,005,232	(86,549)	2,949,078
Income/(Loss) on Discontinued Operations, net of Income Taxes	(25,920)	82,074	(238,787)	—	(182,633)
Net Income/(Loss)	$ (79,465)	$166,014	$ 2,766,445	$ (86,549)	$2,766,445

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOW
For the Period January 1, 2003 Through December 5, 2003
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income/(loss)	$ (79,465)	$ 166,014	$ 2,766,445	$ (86,549)	$ 2,766,445
Adjustments to reconcile net income/(loss) to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	(95,360)	(53,400)	20,739	86,549	(41,472)
Depreciation and amortization	131,399	111,794	13,507	—	256,700
Amortization of deferred financing costs	6,676	7,016	3,948	—	17,640
Write downs and losses on sales of equity method investments	16,284	130,654	—	—	146,938
Deferred income taxes and investment tax credits	(123,237)	(36,015)	181,544	(24,185)	(1,893)
Current tax expense — non cash contribution from members	(17,149)	(54,148)	—	71,297	—
Unrealized (gains)/losses on derivatives	(12,246)	(75,310)	29,540	23,400	(34,616)
Minority interest	—	2,177	—	—	2,177
Restructuring and impairment charges	273,138	93,516	41,723	—	408,377
Fresh start reporting adjustments	—	—	(3,895,541)	—	(3,895,541)
Gain on sale of discontinued operations	3,180	(198,666)	9,155	—	(186,331)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions	59,168	(5,552)	(25,355)	—	28,261
Accounts receivable, net					
Inventory	25,713	(14,512)	2,927	—	14,128
Prepayments and other current assets	(30,388)	8,599	(15,942)	919	(36,812)
Accounts payable	116,452	(57,004)	634,215	—	693,663
Accounts payable-affiliates	189,204	(52,324)	(20,346)	(161,551)	(45,017)
Accrued income taxes	—	—	68,356	(47,112)	21,244
Accrued property and sales taxes	(2,015)	(625)	(519)	—	(3,159)
Accrued salaries, benefits, and related costs	(41,037)	92,331	(10,604)	—	40,690
Accrued interest	(14,865)	54,773	119,592	(919)	158,581
Other current liabilities	29,631	46,438	(98,866)	—	(22,797)
Other assets and liabilities	15,940	(68,051)	3,414	—	(48,697)
Net Cash Provided (Used) by Operating Activities	451,023	97,705	(172,068)	(138,151)	238,509
Cash Flows from Investing Activities					
Investment in subsidiaries	—	—	129,351	(129,351)	—
Proceeds from sale of discontinued operations	—	18,612	—	—	18,612
Proceeds from sale of investments	—	107,174	—	—	107,174
Proceeds from sale of turbines	—	—	70,717	—	70,717
(Increase) in trust funds	(13,971)	—	—	—	(13,971)
Decrease/(increase) in restricted cash	(197,692)	(54,803)	—	—	(252,495)
Decrease/(increase) in notes receivable	98,064	42,493	285	(142,495)	(1,653)
Capital expenditures	(55,833)	(6,450)	(51,219)	—	(113,502)
Investments in projects	(3,672)	(5,259)	8,370	—	(561)
Net Cash Provided (Used) by Investing Activities	(173,104)	101,767	157,504	(271,846)	(185,679)
Cash Flows from Financing Activities					
Capital contributions from parent	(135,251)	(132,251)	—	267,502	—
Proceeds from issuance of long-term debt	—	39,988	—	—	39,988
Deferred debt issuance costs	(7,640)	(447)	(10,453)	—	(18,540)
Principal payments on long-term debt	(4,055)	(189,832)	—	142,495	(51,392)
Net Cash Provided (Used) by Financing Activities	(146,946)	(282,542)	(10,453)	409,997	(29,944)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(22,276)	—	—	(22,276)
Change in Cash from Discontinued Operations	—	34,512	—	—	34,512
Net Increase in Cash and Cash Equivalents	130,973	(70,834)	(25,017)	—	35,122
Cash and Cash Equivalents at Beginning of Period	63,403	228,135	69,322	—	360,860
Cash and Cash Equivalents at End of Period	$ 194,376	$ 157,301	$ 44,305	$ —	$ 395,982

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2002
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$1,376,586	$ 510,434	$ 55,492	$ (4,219)	$ 1,938,293
Operating Costs and Expenses					
Cost of majority-owned operations	918,941	345,133	72,750	(4,378)	1,332,446
Depreciation and amortization	126,258	69,512	11,257	—	207,027
General, administrative and development	49,759	53,252	115,682	159	218,852
Other charges (credits)					
Restructuring and impairment charges	108,236	2,091,845	362,979	—	2,563,060
Total operating costs and expenses	1,203,194	2,559,742	562,668	(4,219)	4,321,385
Operating Income/(Loss)	173,392	(2,049,308)	(507,176)	—	(2,383,092)
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	(690,627)	(454)	(2,944,968)	3,636,049	—
Equity in earnings of unconsolidated affiliates	17,786	50,398	812	—	68,996
Write downs and losses on sales of equity method investments	(16,255)	(182,035)	(2,182)	—	(200,472)
Other income, net	9,648	9,221	(4,127)	(3,311)	11,431
Interest expense	(142,775)	(115,741)	(196,977)	3,311	(452,182)
Total other expense	(822,223)	(238,611)	(3,147,442)	3,636,049	(572,227)
Income/(Loss) From Continuing Operations Before Income Taxes	(648,831)	(2,287,919)	(3,654,618)	3,636,049	(2,955,319)
Income Tax Expense/(Benefit)	(1,905)	25,374	(190,336)	—	(166,867)
Income/(Loss) From Continuing Operations	(646,926)	(2,313,293)	(3,464,282)	3,636,049	(2,788,452)
Income/(Loss) on Discontinued Operations, net of Income Taxes	(25,328)	(650,502)	—	—	(675,830)
Net Income/(Loss)	$ (672,254)	$(2,963,795)	$(3,464,282)	$3,636,049	$(3,464,282)

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2002
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income/(loss)	$(672,254)	$(2,963,795)	$(3,464,282)	$3,636,049	$(3,464,282)
Adjustments to reconcile net income/(loss) to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	689,451	(19,810)	2,944,156	(3,636,049)	(22,252)
Depreciation and amortization	131,876	143,491	11,256	—	286,623
Amortization of deferred financing costs	3,450	13,046	11,871	—	28,367
Write downs and losses on sales of equity method investments	11,975	182,035	2,182	—	196,192
Deferred income taxes and investment tax credits	(44,442)	(9,847)	(130,273)	(45,572)	(230,134)
Current tax expense — non cash contribution from members	3,874	(27,477)	—	23,603	—
Unrealized (gains)/losses on derivatives	(18,439)	47,422	(31,726)	—	(2,743)
Minority interest	—	(19,325)	—	—	(19,325)
Amortization of out of market power contracts	(89,415)	—	—	—	(89,415)
Restructuring and impairment charges	109,207	2,760,390	274,912	—	3,144,509
Gain on sale of discontinued operations	—	(2,814)	—	—	(2,814)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions					
Accounts receivable, net	(72,106)	29,883	26,736	—	(15,487)
Accounts receivable-affiliates	1,100	1,171	—	—	2,271
Inventory	49,795	(7,185)	(14)	—	42,596
Prepayments and other current assets	(44,999)	13,412	(26,781)	—	(58,368)
Accounts payable	(38,789)	180,682	137,007	—	278,900
Accounts payable-affiliates	358,032	417,072	(728,193)	138	47,049
Accrued income taxes	—	—	22,168	21,969	44,137
Accrued property and sales taxes	(7,678)	34,634	525	—	27,481
Accrued salaries, benefits, and related costs	(8,253)	2,708	(19,367)	—	(24,912)
Accrued interest	33,985	40,488	128,761	—	203,234
Other current liabilities	7,516	(8,560)	48,736	—	47,692
Other assets and liabilities	(4,428)	10,818	4,333	—	10,723
Net Cash Provided (Used) by Operating Activities	399,458	818,439	(787,993)	138	430,042
Cash Flows from Investing Activities					
Proceeds from sale of discontinued operations	—	160,791	—	—	160,791
Proceeds from sale of investments	—	68,517	—	—	68,517
Decrease/(increase) in restricted cash	(138,798)	(109,004)	50,000	—	(197,802)
Decrease/(increase) in notes receivable	(28,247)	(230,733)	(29,728)	79,464	(209,244)
Capital expenditures	(92,003)	(1,349,163)	1,433	—	(1,439,733)
Investments in projects	(36,047)	(25,896)	(2,053)	—	(63,996)
Investment in subsidiaries	(27,967)	—	(145,732)	173,699	—
Distributions from subsidiaries	—	—	216,751	(216,751)	—
Net Cash Provided (Used) by Investing Activities	(323,062)	(1,485,488)	90,671	36,412	(1,681,467)
Cash Flows from Financing Activities					
Proceeds from issuance of stock	—	—	4,065	—	4,065
Capital contributions from parent	81,427	92,487	500,000	(173,914)	500,000
Distributions to parent	—	(216,751)	—	216,751	—
Net borrowings under line of credit agreement	(40,000)	—	830,000	—	790,000
Proceeds from issuance of long-term debt	37,869	963,000	165,288	(79,387)	1,086,770
Principal payments on long-term debt	(99,331)	(92,174)	(740,000)	—	(931,505)
Net Cash Provided (Used) by Financing Activities	(20,035)	746,562	759,353	(36,550)	1,449,330
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(1,092)	20,426	5,616	—	24,950
Change in Cash from Discontinued Operations	—	51,267	—	—	51,267
Net Increase in Cash and Cash Equivalents	55,269	151,206	67,647	—	274,122
Cash and Cash Equivalents at Beginning of Period	8,134	76,929	1,675	—	86,738
Cash and Cash Equivalents at End of Period	$ 63,403	$ 228,135	$ 69,322	$ —	$ 360,860

(1) All significant intercompany transactions have been eliminated in consolidation.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Stockholders of NRG Energy, Inc.:

Our audit of the consolidated financial statements referred to in our report dated March 10, 2004, except as to Notes 6, 23, and 33, which are as of December 6, 2004, appearing in this Annual Report on Form 10-K also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Annual Report on Form 10-K. In our opinion, this financial statement schedule for the period from December 6, 2003 to December 31, 2003 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 10, 2004, except as to
Notes 6, 23, and 33,
which are as of December 6, 2004.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Stockholders of NRG Energy, Inc.:

Our audits of the consolidated financial statements referred to in our report dated March 10, 2004, except as to Notes 6, 23, and 33, which are as of December 6, 2004, appearing in this Annual Report on Form 10-K also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Annual Report on Form 10-K. In our opinion, this financial statement schedule for the period from January 1, 2003 to December 5, 2003 and for the year ended December 31, 2002, presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 10, 2004, except as to
Notes 6, 23, and 33,
which are as of December 6, 2004.

NRG ENERGY, INC.

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2004, 2003, and 2002

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(In thousands)		
Allowance for doubtful accounts, deducted from accounts receivable in the balance sheet:					
Reorganized NRG					
Year ended December 31, 2004	$ —	$ 856	$ 458	$ (303)	$ 1,011
December 6 - December 31, 2003 ...	$ —	$ — —	$ —	$ —	$ —
Predecessor Company					
January 1 - December 5, 2003	$ 18,163	$ 15,576	$ —	$ (33,739)	$ —*
Year ended December 31, 2002	$ 13,634	$ 4,529	$ —	$ —	$ 18,163
Income tax valuation allowance, deducted from deferred tax assets in the balance sheet:					
Reorganized NRG					
Year ended December 31, 2004	$1,241,101	$ —	$(276,969)	$(256,261)	$ 707,871
December 6 - December 31, 2003 ...	$1,241,616	$ (515)	$ —	$ —	$ 1,241,101
Predecessor Company					
January 1 - December 5, 2003	$1,170,301	$ 71,315	$ —	$ —	$ 1,241,616*
Year ended December 31, 2002	$ 71,446	$1,006,540	$ 92,315	$ —	$ 1,170,301

* December 6, 2003 — Fresh Start Balance

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

NRG ENERGY, INC.
(Registrant)

/s/ DAVID W. CRANE

David W. Crane,
Chief Executive Officer
(Principal Executive Officer)

/s/ ROBERT C. FLEXON

Robert C. Flexon,
Chief Financial Officer
(Principal Financial Officer)

/s/ JAMES J. INGOLDSBY

James J. Ingoldsby,
Controller
(Principal Accounting Officer)

Date: March 29, 2005

POWER OF ATTORNEY:

Each person whose signature appears below constitutes and appoints David W. Crane, Timothy W. J. O'Brien and Tanuja M. Dehne, each or any of them, such person's true and lawful attorney-in-fact and agent with full power of substitution and resubstitution for such person and in such person's name, place and stead, in any and all capacities, to sign any and all amendments to this report on Form 10-K, and to file the same with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing necessary or desirable to be done in and about the premises, as fully to all intents and purposes as such person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or his or their substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

In accordance with the Exchange Act, this report has been signed by the following persons on behalf of the registrant in the capacities indicated on March 29, 2005.

Signature	Title	Date
/s/ DAVID W. CRANE David W. Crane	President and Chief Executive Officer	March 29, 2005
/s/ HOWARD COSGROVE Howard Cosgrove	Chairman of the Board	March 29, 2005
/s/ JOHN F. CHLEBOWSKI John F. Chlebowski	Director	March 29, 2005
/s/ LAWRENCE COBEN Lawrence Coben	Director	March 29, 2005
/s/ STEPHEN CROPPER Stephen Cropper	Director	March 29, 2005
/s/ HERBERT TATE Herbert Tate	Director	March 29, 2005
/s/ THOMAS WEIDEMEYER Thomas Weidemeyer	Director	March 29, 2005
/s/ WALTER YOUNG Walter Young	Director	March 29, 2005

Exhibit 31.1

CERTIFICATION

I, David W. Crane, certify that:

1. I have reviewed this annual report on Form 10-K of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DAVID W. CRANE

David W. Crane
Chief Executive Officer
(Principal Executive Officer)

Date: March 29, 2005

Exhibit 31.2

CERTIFICATION

I, Robert C. Flexon, certify that:

1. I have reviewed this annual report on Form 10-K of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ROBERT C. FLEXON

Robert C. Flexon
Chief Financial Officer
(Principal Financial Officer)

Date: March 29, 2005

EXHIBIT 31.3

CERTIFICATION

I, James J. Ingoldsby, certify that:

1. I have reviewed this annual report on Form 10-K of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JAMES J. INGOLDSBY

James J. Ingoldsby
Controller
(Principal Accounting Officer)

Date: March 29, 2005

EXHIBIT 32

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of NRG Energy, Inc. (the Company) on Form 10-K for the year ended December 31, 2004, as filed with the Securities and Exchange Commission on the date hereof (Form 10-K), each of the undersigned officers of the Company certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company as of the dates and for the periods expressed in the Form 10-K.

Date: March 29, 2005

/s/ DAVID W. CRANE

David W. Crane,
Chief Executive Officer
(Principal Executive Officer)

/s/ ROBERT C. FLEXON

Robert C. Flexon
Chief Financial Officer
(Principal Financial Officer)

/s/ JAMES J. INGOLDSBY

James J. Ingoldsby
Controller
(Principal Accounting Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to NRG Energy, Inc. and will be retained by NRG Energy, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT INDEX

2.1	Third Amended Joint Plan of Reorganization of NRG Energy, Inc., NRG Power Marketing, Inc., NRG Capital LLC, NRG Finance Company I LLC, and NRGenerating Holdings (No. 23) B.V.(7)
2.2	First Amended Joint Plan of Reorganization of NRG Northeast Generating LLC (and certain of its subsidiaries), NRG South Central Generating (and certain of its subsidiaries) and Berrians I Gas Turbine Power LLC.(7)
3.1	Amended and Restated Certificate of Incorporation.(2)
3.2	Amended and Restated By-Laws.(8)
3.3	Certificate of Designation of 4.0% Convertible Perpetual Preferred Stock, as filed with the Secretary of State of the State of Delaware on December 20, 2004.(10)
4.1	Indenture dated as of December 23, 2003 by and among NRG Energy, Inc., certain subsidiaries of NRG Energy, Inc. and Law Debenture Trust Company of New York, as Trustee, re: NRG Energy, Inc.'s 8% Second Priority Senior Secured Notes due 2013.(2)
4.2	Purchase Agreement dated as of December 17, 2003 by and among NRG Energy, Inc., as Issuer, certain subsidiaries of NRG Energy, Inc., as guarantors, and Lehman Brothers, Inc., Credit Suisse First Boston LLC, Citigroup Global Markets Inc. and Deutsche Bank Securities, Inc., as Initial Purchasers, re: $1,250,000,000 8% Second Priority Senior Secured Notes due 2013.(2)
4.3	Registration Rights Agreement dated as of December 23, 2003 by and among NRG Energy, Inc., as Issuer, certain subsidiaries of NRG Energy, Inc., as Guarantors, and Lehman Brothers Inc., Credit Suisse First Boston LLC, Citigroup Global Markets Inc. and Deutsche Bank Securities, Inc., as Initial Purchasers.(2)
4.4	Purchase Agreement dated as of January 21, 20032004 by and among NRG Energy, as Issuer, certain subsidiaries of NRG Energy, Inc., as Guarantors, and Credit Suisse First Boston LLC and Lehman Brothers, Inc., as Initial Purchasers, re: $475,000,000 8% Second Priority Senior Secured Notes due 2013.(2)
4.5	Registration Rights Agreement dated as of January 28, 2004 by and among NRG Energy, Inc., as Issuer, certain subsidiaries of NRG Energy, Inc., as Guarantors, and Credit Suisse First Boston LLC and Lehman Brothers, Inc., as Initial Purchasers.(2)
4.6	Amended and Restated Common Agreement among XL Capital Assurance Inc., Goldman Sachs Mitsui Marine Derivative Products, L.P., Law Debenture Trust Company of New York, as Trustee, The Bank of New York, as Collateral Agent, NRG Peaker Finance Company LLC and each Project Company Party thereto dated as of January 6, 2004, together with Annex A to the Common Agreement.(2)
4.7	Amended and Restated Security Deposit Agreement among NRG Peaker Finance Company, LLC and each Project Company party thereto, and the Bank of New York, as Collateral Agent and Depositary Agent, dated as of January 6, 2004.(2)
4.8	NRG Parent Agreement by NRG Energy, Inc. in favor of the Bank of New York, as Collateral Agent, dated as of January 6, 2004.(2)
4.9	Indenture dated June 18, 2002, between NRG Peaker Finance Company LLC, as Issuer, Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Rockford LLC, NRG Rockford II LLC and Sterlington Power LLC, as Guarantors, XL Capital Assurance Inc., as Insurer, and Law Debenture Trust Company, as Successor Trustee to the Bank of New York.(4)
4.10	Registration Rights Agreement, dated December 21, 2004, by and among NRG Energy, Inc., Citigroup Global Markets Inc. and Deutsche Bank Securities Inc.(9)
4.11	Registration Rights Agreement, dated December 5, 2003, among NRG Energy, Inc. and the holders of NRG Energy, Inc. common stock named therein.(3)
10.1*	Employment Agreement dated November 10, 2003 between NRG Energy, Inc. and David Crane.(2)
10.2	Note Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc. and each of the purchasers named therein.(5)
10.3	Master Shelf and Revolving Credit Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc., The Prudential Insurance Registrants of America and each Prudential Affiliate, which becomes party thereto.(5)

10.4	Asset Sales Agreement, dated December 23, 1998, between NRG Energy, Inc., and Niagara Mohawk Power Corporation.(6)
10.5	Generating Plant and Gas Turbine Asset Purchase and Sale Agreement for the Arthur Kill generating plants and Astoria gas turbines, dated January 27, 1999, between NRG Energy and Consolidated Edison Company of New York, Inc.(6)
10.6	Amendment to the Asset Sales Agreement, dated June 11, 1999, between NRG Energy, Inc., and Niagara Mohawk Power Corporation.(6)
10.7*	Key Executive Retention, Restructuring Bonus and Severance Agreement between NRG Energy, Inc. and Scott J. Davido dated July 1, 2003.(2)
10.8*	Severance Agreement between NRG Energy, Inc. and Ershel Redd Jr. dated January 30, 2003.(4)
10.9*	Severance Agreement between NRG Energy, Inc. and William Pieper dated March 1, 2003.(2)
10.10*	Severance Agreement between NRG Energy, Inc. and George Schaefer dated December 18, 2002.(4)
10.11*	Severance Agreement between NRG Energy, Inc. and John P. Brewster dated July 23, 2003.(2)
10.12	Stock Purchase Agreement dated December 13, 2004, by and among NRG Energy, Inc. and MatlinPatterson Global Advisers LLC, MatlinPatterson Global Opportunities Partners, L.P. and MatlinPatterson Global Opportunities Partners (Bermuda) L.P.(11)
10.13*	NEO 2004 AIP Payout and 2005 Base Salary Table.(8)
10.14*	Form of NRG Energy Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Officers and Key Management.(1)
10.15*	Form of NRG Energy Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Directors.(1)
10.16*	NRG Energy, Inc. Long-Term Incentive Plan.(15)
10.17*	Form of NRG Energy, Inc. Long-Term Incentive Plan Non-Qualified Stock Option Agreement.(12)
10.18*	Form of NRG Energy, Inc. Long-Term Incentive Plan Restricted Stock Unit Agreement.(12)
10.19*	Annual Incentive Plan for Designated Corporate Officers.(13)
10.20*	Letter Agreement dated March 5, 2004 between NRG Energy and Scott J. Davido.(14)
10.21*	Letter Agreement dated March 5, 2004 between NRG Energy and Ershel C. Redd Jr.(14)
10.22*	Letter Agreement dated March 5, 2004 between NRG Energy and John P. Brewster.(14)
10.23*	Letter Agreement dated March 5, 2004 between NRG Energy and Timothy W. O'Brien.(14)
10.24*	Letter Agreement dated February 19, 2004 between NRG Energy and Robert C. Flexon.(14)
10.25	Credit Agreement dated as of December 23, 2003, as amended and restated as of December 24, 2004, among NRG Energy, Inc., NRG Power Marketing, Inc., the Lenders party hereto, Credit Suisse First Boston, as Administrative Agent, Credit Suisse First Boston and Goldman Sachs Credit Partners L.P., as Joint Lead Book Runners, Joint Lead Arrangers and Co-Documentation Agents, and Goldman Sachs Credit Partners L.P., as Syndication Agent.(1)
10.26	Guarantee and Collateral Agreement dated as of December 23, 2003, as amended and restated as of December 24, 2004, made by NRG Energy, Inc., NRG Power Marketing, Inc. and certain of the subsidiaries of NRG Energy, Inc. in favor of Deutsche Bank Trust Company Americas, as Priority Collateral Trustee, Parity Collateral Trustee and Account Collateral Trustee, Credit Suisse First Boston, as Administrative Agent, and Law Debenture Trust Company of New York, as Trustee.(1)
10.27	Collateral Trust Agreement dated as of December 23, 2003, as amended and restated as of December 24, 2004, among NRG Energy, Inc., NRG Power Marketing, Inc., the Guarantors from time to time party hereto, Credit Suisse First Boston, as Administrative Agent, Law Debenture Trust Company of New York, as Trustee, and Deutsche Bank Trust Company Americas, as Priority Collateral Trustee, Parity Collateral Trustee and Account Collateral Trustee.(1)
10.28	Railroad Car Full Service Master Leasing Agreement, dated as of February 18, 2005, between General Electric Railcar Services Corporation and NRG Power Marketing Inc.(1)
10.29	Commitment Letter, dated February 18, 2005, between General Electric Railcar Services Corporation and NRG Power Marketing Inc.(1)
10.30	Summary of Director Compensation.(1)
21	Subsidiaries of NRG Energy. Inc.(1)
23.1	Consent of KPMG LLP.(1)

23.2	Consent of PricewaterhouseCoopers LLP.(1)
23.3	Consent of PricewaterhouseCoopers LLP. (with respect to West Coast Power LLC)(1)
31.1	Rule 13a-14(a)/15d-14(a) certification of David W. Crane.(1)
31.2	Rule 13a-14(a)/15d-14(a) certification of Robert C. Flexon.(1)
31.3	Rule 13a-14(a)/15d-14(a) certification of James J. Ingoldsby.(1)
32	Section 1350 Certification.(1)
99.1	Financial Statements of West Coast Power LLC.(1)

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* Exhibit relates to compensation arrangements.

(1) Filed herewith.

(2) Incorporated herein by reference to NRG Energy, Inc.'s annual report on Form 10-K filed on March 16, 2004.

(3) Incorporated herein by reference to NRG Energy Inc.'s Amendment No. 2 to its annual report on Form 10-K filed on November 3, 2004.

(4) Incorporated herein by reference to NRG Energy, Inc.'s annual report on Form 10-K filed on March 31, 2003.

(5) Incorporated herein by reference to NRG Energy's Registration Statement on Form S-1, as amended, Registration No. 333-33397.

(6) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended June 30, 1999.

(7) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on November 19, 2003.

(8) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on March 3, 2005.

(9) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on December 27, 2004.

(10) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on December 27, 2004.

(11) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K/A filed on December 14, 2004.

(12) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended September 30, 2004.

(13) Incorporated herein by reference to NRG Energy, Inc.'s 2004 proxy statement on Schedule 14A filed on July 12, 2004.

(14) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended March 31, 2004.

(15) Incorporated herein by reference to NRG Energy Inc.'s Registration Statement on Form S-8, Registration No. 333-114007.

EBITDA Reconciliation

The following table summarizes the calculation of EBITDA and provides a reconciliation to net income/(loss):

	Twelve Months Ended 12/31/2004
Net Income:	**$ 185,617**
Plus:	
Income tax expense	65,112
Interest expense	276,160
Amortization of finance costs	51,465
Amortization of debt discount/premium	13,308
Depreciation expense	209,295
WCP CDWR contract amortization	115,751
Amortization of power contracts	35,316
Amortization of emission credits	17,829
EBITDA	**$ 969,853**
Fixed assets impairments	44,661
Discontinued operations	(23,472)
Corporate relocation charges	16,167
Reorganization items	(13,390)
FERC-authorized settlement with CL&P	(38,357)
Write down of note receivable	4,572
Write downs/loss on sales of equity investments	16,270
Adjusted EBITDA	**$ 976,304**

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