[POSITIONING FOR THE FUTURE]

2008 ANNUAL REPORT

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625 Ninth Street
Rapid City, SD 57701
blackhillscorp.com

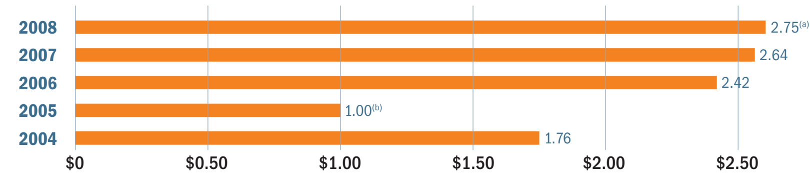
Black Hills Corporation
Improving life with energy

[CORPORATE HIGHLIGHTS]

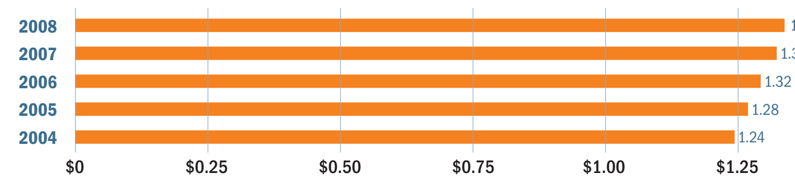
	2008	2007	2006
Earnings per share – diluted	$2.75	$2.64	$2.42
Dividends paid per share	$1.40	$1.37	$1.32
Book value per outstanding share	$27.19	$25.66	$23.68
Year-end stock price	$26.96	$44.10	$36.94
Five-year dividend growth rate	3.1%	3.4%	3.3%
Payout ratio	51%	52%	55%
Dividend yield on market value at year-end	5.2%	3.1%	3.6%
Return on average year-end common equity	10.4%	11.2%	10.6%
Price-earnings multiple at year-end	10	17	15
Electric Utilities sales (millions of KWH)*	5,749	3,968	4,142
Electric Utility natural gas sales (millions of Dekatherms)	4,773	4,428	4,388
Natural Gas Utilities sales (millions of Dekatherms)*	23,054	–	–
Total independent power capacity (MW) at year-end**	141	983	989
Tons of coal sold (thousands of tons)	6,017	5,049	4,717
Oil and natural gas production sold (MMcfe)	13,534	14,627	14,414
Average daily physical volume natural gas marketed (MMBtu)	1,873,400	1,743,500	1,598,200
Average daily physical volume crude oil marketed (barrels)	7,880	8,600	8,800

* Includes Black Hills Energy results from the July 14, 2008, acquisition date through December 31, 2008.
** In 2008, we sold seven IPP plants with 974 MW of capacity

EARNINGS PER SHARE

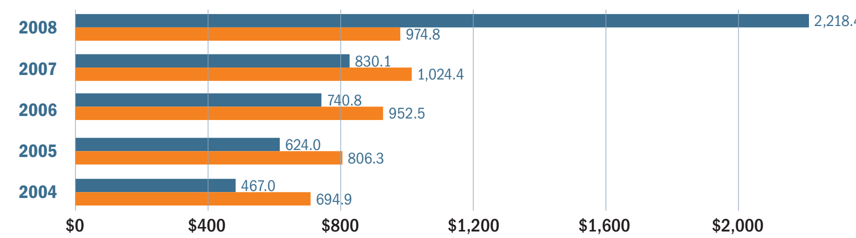


DIVIDENDS



BUSINESS GROUP ASSETS[c][d]

Utilities[e]
Non-regulated Energy



a Includes $3.66 per share for the gain on sale of the IPP assets, a $1.61 per share charge for an unrealized mark-to-market charge for certain interest rate swaps and $1.55 per share charge for an Oil and Gas ceiling test impairment charge.
b Includes a $0.98 per share asset impairment charge.
c Excludes corporate assets and assets of discontinued operations.
d In 2008 we sold seven IPP assets with 974 MW of capacity.
e 2008 includes assets of Black Hills Energy, acquired on July 14, 2008.

[CHAIRMAN'S LETTER]

Dear Shareholders,

The year 2008 was one of tremendous change, accomplishment and celebration for Black Hills Corporation. In addition to celebrating our 125th anniversary, we also transformed the Company by successfully completing the two largest transactions in our history.

Now, we are focused forward and are optimistic about the future. These are exciting times for our Company and our industry. New technologies, changing regulations, uncertain market and economic conditions and the growing needs of our customers mean that a significant number of challenges lay ahead. Each day's new challenges bring opportunities for us to improve and become an even stronger organization.

Although we remain excited about the future, these difficult economic times have led us to be more conservative. We are operating efficiently, reducing expenses and managing the timing of our capital expenditures to preserve liquidity in today's credit-constrained environment.

During our 125 years, we have overcome many obstacles to become the company we are today.

Because of our stable foundation, strong values and cautious approach, we will endure and be ready to accelerate implementation of our strategic growth plans when market conditions improve.

[Aquila Acquisition]

The Aquila acquisition demonstrates why we have been successful for 125 years. Overnight, our utility customer base increased fivefold and the number of employees doubled by adding one electric utility and four natural gas utilities.

To provide our customers with a seamless transition, project teams worked diligently for countless hours. The integration process is ongoing and continues to provide our employees opportunities to strengthen their technical and leadership skills. This monumental milestone in our Company's history has confirmed that we are capable of tremendous accomplishments. As we move forward, we know that the systems, processes and platforms we are building will serve us well, and we are proud of the value we are creating.

Some additional benefits of the acquisition include:

- More predictable and stable cash flows and income from the acquired natural gas and electric utilities
- A stronger operational, systems and process platform to support future utility acquisitions
- The chance to demonstrate our proven regulatory approach, founded on honest, open communication with federal and state regulators
- The opportunity to combine two strong utility employee teams
- A diversified business mix more heavily weighted to regulated utility properties that still provides considerable growth and upside opportunity from our non-regulated energy businesses
- An improved business risk profile and improved credit metrics

[IPP Sale]

In addition to the utility acquisition, we completed another major milestone with the $840 million sale of seven of our independent power plants. The sale process was comprehensive and produced excellent value for our shareholders. The cash received from the sale provided a substantial portion of the financing necessary to acquire the five utilities from Aquila. Through careful tax planning, we deferred tax payments related to the sale of approximately $185 million.

Despite this sale, we plan to remain an active participant in the IPP business and believe that permitting, constructing and operating power generation assets remains one of our core strengths.

[Vision, Mission, Values]

In 2008, we emphasized the traits that have contributed to our success and identified additional traits that will be critical to our success in the future. To do this, we created a vision and updated our mission and values and then undertook a campaign to communicate them to our employees.

Vision: We strive to "be the energy partner of choice." Whether our customers are served by our regulated or non-regulated businesses, we want them to value our service and business relationship.

Mission: Every day, we want to be "improving life with energy." We produce, market and deliver the vital electricity, coal, oil and natural gas that our customers need. Through our efforts, products and services, we also share our personal energy to strengthen our communities and support growth and development.

Values: These represent the traits that are demonstrated by Black Hills employees.

Agility
Communication
Creating Value
Customer Service
Integrity
Leadership
Partnership
Respect

A vital portion of our value system is our continued commitment to safety. This commitment ensures that our employees have the tools, training and resources necessary to perform their jobs and return home unharmed at the end of each work day. Our employees' dedication to working safely was evident in the various no lost-time accident anniversaries many of our business units reached in 2008.

[Wygen I, II and III]

Our ability to successfully plan, permit, construct and operate power plants was evident again in 2008. On the first day of 2008, Wygen II began serving Cheyenne Light, Fuel & Power customers. This 95 megawatt coal-fired power plant – with state-of-the-art emissions control technology – is among the cleanest in the United States. It is also among the first coal-fired plants in the U.S. equipped with mercury scrubbing technology.

We also secured the final approval necessary to begin building Wygen III, a 110 megawatt, coal-fired power plant that will primarily serve the growing load requirements of Black Hills Power. This power plant is a sister plant to Wygen II and will share a control room, warehouse, coal-handling facilities and operating staff, thus helping to optimize operating costs. Construction commenced in the spring of 2008 and is expected to be completed by mid-2010.

At the beginning of 2009, Black Hills completed the $51 million sale of 23.5 percent ownership in our Wygen I power generation facility to the Municipal Energy Agency of Nebraska. The agreement with MEAN also provides payments for costs associated with administrative services, site leases, plant operations and coal supply provided by Black Hills subsidiaries during the life of the facility. This deal changed our relationship with MEAN from that of a wholesale power customer under a term contract to a partner for the life of the plant.

[Black Hills Energy – Colorado Electric, Electric Resource Plan]

Black Hills Energy – Colorado Electric filed an Electric Resource Plan with the Colorado Public Utilities Commission in August 2008. Through the plan, the Company seeks approval to build generation to supply electricity to our 92,000 customers in the southeastern part of the state when the utility's current power purchase agreement, which provides 75 percent of the electricity requirements, expires on Dec. 31, 2011.

On Feb. 25, 2009, the Colorado Public Utilities Commission issued an initial decision to allow Black Hills Energy to build two of five utility-owned and -operated generation facilities and waive the PUC's competitive bidding rules. Until March 16, 2009, the decision is subject to requests by parties to the proceeding for reconsideration by the Commission. In addition, Black Hills Corporation, through its IPP subsidiary, will have the opportunity to submit a bid, along with other interested parties, to serve all or a portion of the remaining customer requirement. This competitive bidding and selection process is expected to be completed in the fourth quarter of 2009.

[Energy Marketing and Oil and Gas]

Enserco Energy, our energy marketing subsidiary, finished the year strong. Prudent credit and risk management – as peer companies and counter parties struggled because of the crisis in the financial markets – allowed Enserco to finish the year without any significant credit losses or exposure. Despite a slow start to the year, the business took advantage of market opportunities and made a significant contribution to 2008 results.

Black Hills Exploration & Production, our natural gas and crude oil production subsidiary, recorded a loss of $49.7 million for the year, a much different outcome than was anticipated at mid-year during a period of record prices for oil and natural gas. This loss was dominated by a non-cash "ceiling test" impairment charge of $59 million after tax recorded in the fourth quarter of 2008, largely driven by very low year-end oil and natural gas prices. Both production and reserves were less than in the previous year.

[Leadership Changes]

The organizational changes in 2008, including those resulting from the Aquila transaction, significantly strengthened our leadership team. Scott Buchholz, Senior Vice President and Chief Information Officer, and Lynn Wilson, Senior Vice President of Communications and Investor Relations, both joined our Company from Aquila when the transaction closed. In July, we welcomed Anthony Cleberg as Executive Vice President and Chief Financial Officer. Richard Kinzley was promoted to Vice President, Strategic Planning and Development in September after the resignation of Maurice Klefeker. Jeff Berzina was promoted to Vice President of Finance in November. And at the beginning of 2009, Bob Myers was selected as Senior Vice President of Human Resources to replace Jim Mattern, who will be retiring in mid-2009.

Our Black Hills Corporation family also was deeply saddened by the death of Dan Landguth, our former Chairman, President and Chief Executive Officer, in January 2009. We owe Dan a tremendous debt of gratitude for his vision and unwavering dedication to our Company for 36 years, and he is sincerely missed.

[125 Years]

As we celebrated our 125th anniversary throughout 2008, we came to a fuller understanding of how growth has been a driving force during the history of Black Hills Corporation. We expanded our business operations and geographic footprint, diversified our asset base, and continued to attract a dedicated group of talented employees to serve our customers.

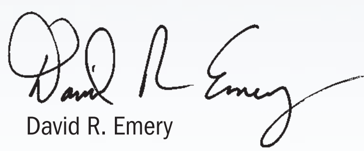
To commemorate our 125 years, we commissioned a history book, “Improving Life With Energy.” To say “thank you” for being a vital component of our remarkable accomplishments, we presented the book to all employees and retirees. The book was in recognition of the contribution each individual has made to the success of Black Hills and a gesture of appreciation for their continued support as we strive to deliver results in the decades to come.

[Strategic Plan – Future Investments]

Careful planning plays a vital role in providing long-term, reliable and economical energy. Right now, we have the most clearly defined growth plan in our history. We have long-term goals and focused capital expenditure projects with teams and processes to ensure prudent management of our assets and success in the future.

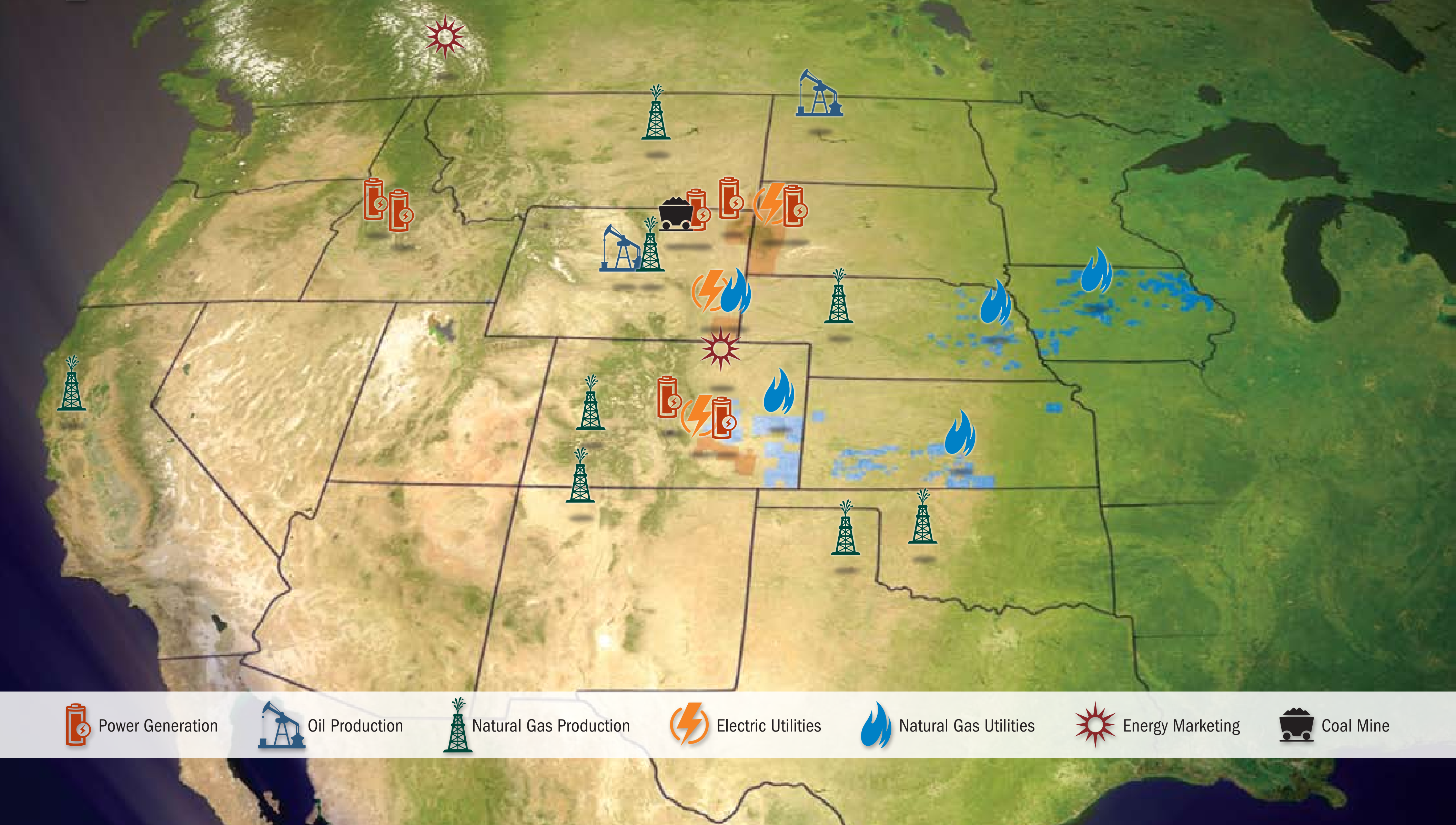
Although we can’t predict what the future holds, our legacy and our values will guide us as we face the challenges ahead. We have an obligation and a commitment – to our shareholders, customers and the generations to come – to go forward thoughtfully. We take this duty seriously as we constantly strive to fulfill our mission of Improving Life with Energy.

Sincerely,



David R. Emery

We are a diversified energy company with a tradition of exemplary service and a vision to be the energy partner of choice. Based in Rapid City, S.D., with corporate offices in Golden, Colo., and Omaha, Neb, the Company serves 750,000 utility customers in Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. The Company's non-regulated businesses generate wholesale electricity, produce natural gas, oil and coal, and market energy. We partner to produce results that improve life with energy.



[UTILITIES] Committed to our customers.

Our utilities group conducts electric and natural gas utility operations in Colorado, Iowa, Kansas, Nebraska, Montana, South Dakota, and Wyoming. Additionally, our electric utilities sell excess power to other utilities and marketing companies, including affiliates. Our natural gas utilities also release excess capacity to pipelines and other pipeline customers when we do not need such pipeline capacity for our natural gas utility customers.

Electric Utilities

- Generates, transmits and distributes electricity to approximately 202,100 customers in South Dakota, Wyoming, Colorado and Montana.
- Includes the operations of Black Hills Power (South Dakota, Wyoming and Montana), Cheyenne Light (Wyoming), and Black Hills Energy - Colorado Electric (Colorado).
- Cheyenne Light also distributes natural gas to approximately 33,300 natural gas utility customers in Wyoming.
- Colorado Electric was acquired on July 14, 2008 and uses the name Black Hills Energy.
- Black Hills Power set a new 430 MW peak electric demand in July 2007.
- Cheyenne Light set a new 168 MW peak electric demand in August 2008.
- Colorado Electric set a new 306 MW peak electric demand in August 2008.
- Black Hills Power has 434 MW of power generation plus 50 MW of purchased power under long-term contract.
- Wygen II, a 95 MW mine-mouth, coal-fired power plant went into commercial service January 1, 2008 as a Cheyenne Light rate-base asset. Remaining Cheyenne Light power requirements served by our non-regulated power generation subsidiary under contract.
- Colorado Electric has 101 MW of power generation plus 280 MW of purchased capacity and energy in 2009, increasing 10 MW per year to 300 MW in 2011.
- Black Hills power sold 3,413 gigawatt-hours of electricity in 2008.
- Cheyenne Light sold 1,236 gigawatt-hours of electricity and 4.7 million dekatherms of natural gas in 2008.
- Colorado Electric sold 1,100 gigawatt-hours of electricity from its July 14, 2008 acquisition date through December 31, 2008.
- Colorado Electric filed an Electric Resource Plan with the Colorado Public Utilities Commission in August 2008 seeking approval to build when the utility's current power purchase agreement, which provides 75 percent of the electricity requirements, expires on Dec. 31, 2011.
- Black Hills Power has unique access to both eastern and western power grids; AC-DC-AC transmission tie provides 70 MW of bi-directional transmission capacity.

Natural Gas Utilities

- Distributes natural gas to approximately 524,000 customers in Colorado, Iowa, Kansas and Nebraska.
- Includes the operations of Colorado Gas, Iowa Gas, Kansas Gas, and Nebraska Gas acquired on July 14, 2008. Each of these utilities uses the name Black Hills Energy in their service areas.
- Colorado Gas sold 3.4 million dekatherm of natural gas from the July 14, 2008 acquisition date through December 31, 2008.
- Iowa Gas sold 13.4 million dekatherm of natural gas from the July 14, 2008 acquisition date through December 31, 2008.
- Kansas Gas sold 12.6 million dekatherm of natural gas from the July 14, 2008 acquisition date through December 31, 2008.
- Nebraska Gas sold 20.4 million dekatherm of natural gas sold from the July 14, 2008 acquisition date through December 31, 2008.

[NON-REGULATED ENERGY] A regional market leader.

Our Non-regulated Energy Group, which operates through various subsidiaries, produces and sells electric capacity and energy through ownership of a diversified portfolio of generating plants; produces coal, natural gas and crude oil primarily in the Rocky Mountain region; and markets and stores natural gas and crude oil. The Non-regulated Energy Group consists of four business segments for reporting purposes: Oil and Gas; Power Generation; Coal Mining; and Energy Marketing.

Oil and Gas

- Development strategy focuses primarily on long-lived natural gas reserves.
- Total 2008 crude oil and natural gas production was 13.5 Bcfe
- 185.5 Bcfe reserves at year-end 2008, with natural gas comprising 83% and crude oil comprising 17% of the total.
- The majority of our reserves are located in select oil and natural gas producing basins in the Rocky Mountain region.

Coal mining

- Our Powder River Basin coal mine near Gillette, Wyoming supports low cost, mine-mouth power generation.
- Record 2008 production: 6.0 million tons.
- 274 million tons of coal reserves at year-end 2008 – a 42 year supply at expected production rates.
- Coal production is expected to increase to supply for additional mine-mouth generating capacity related to the 110 MW Wygen III plant, which is currently being constructed and is expected to utilize approximately 0.6 million tons of coal per year when the plant begins commercial operations in 2010.

Power generation

- 141 MW of power generation capacity.
- Plants concentrated in Wyoming and Idaho.
- During 2008, we sold seven IPP plants with 974 MW of capacity to affiliates of Hastings and IIF for a purchase price of $840 million, subject to customary adjustments.
- Nearly all our capacity is under mid- to long-term tolling arrangements with load-serving electric utilities.
- We serve growth markets in the West by providing coal-fired and natural gas-fired generation for baseload and peaking power capacity.
- Power plant fleet availability of 95.9% in 2008.

Energy marketing

- Focusing on energy delivery, our primary business is marketing and moving natural gas from the Rockies and Canada to markets in the West and Midcontinent.
- The business scope is comprised of the purchase, sale, storage and transportation of natural gas and crude oil, as well as a variety of services including asset optimization, price risk management and customized offerings to producer and end-use clients.
- Average daily physical volumes marketed in 2008: natural gas – 1.9 million MMBtu, up 7% over 2007; crude oil – 7,900 barrels.

[POSITIONING FOR THE FUTURE]

[UTILITIES]

Our regulated utility businesses now serve more than 750,000 electric and natural gas customers in Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. Our dedication to exceptional customer service is evident by the high approval ratings from our customers.

The Aquila acquisition that was completed in July 2008 significantly broadened our regional utility presence, more than doubled our employee count and resulted in a fivefold increase in our utility customer base. These utilities have been re-branded and now operate as Black Hills Energy in their service areas. Post-close activities during the next 18 to 24 months will include systems and processes integration to establish a unified platform to further grow our business and deliver value with a lower risk profile.

[Electric Utilities]

Business at Black Hills Power remained strong in 2008. We began construction of the Wygen III power plant, which is planned for commercial operation by mid-2010. Beginning Jan. 1, 2009, we began to benefit from newly increased transmission rates resulting from a recent FERC transmission rate case. The new rate structure also includes a formula approach to rates that allows us to recover capital investment as it is spent on transmission infrastructure.

At our Black Hills Energy – Colorado Electric utility, in addition to a focus on building generation pertinent to the Electric Resource Plan filed Aug. 8, 2008, we implemented a pilot program for approximately 3,500 electric customers to receive "smart meters" at their homes or businesses in the Pueblo, Colo., area. These meters send customer information wirelessly to the Company's computer system, allowing for more frequent and cost-effective readings and a more accurate bill. The meters also provide opportunities for two-way communication that will facilitate future demand side management initiatives. The long-range goal for the program is to install smart meters on all customer homes and businesses in our Colorado Electric service area.

Black Hills Energy – Colorado Electric also began building a 115-kilovolt transmission line linking Cañon City, Colo., and Victor, Colo., in June 2008. As of February 2009, the utility is 15 miles into the project, and the remaining seven miles of line are expected to be complete later in the year.

Cheyenne Light, Fuel & Power implemented new energy rates in early 2008 representing a $4.4 million increase in natural gas rates and $6.7 million in electric rates. Simultaneously, the 95-megawatt Wygen II coal-fired base load plant was brought on line as scheduled on Jan. 1, 2008. In addition, 30 megawatts of energy from the Happy Jack Wind Farm was integrated into Black Hills Power's and Cheyenne Light's energy supply mix.

[Natural Gas Utilities]

Our natural gas utilities are focused on the continued investment and strengthening of our natural gas distribution systems. This grows our utility rate base and supports our ability to provide safe and reliable service to our customers.

We have pending rate cases for our Black Hills Energy Iowa Gas and Colorado Gas utilities. Interim rates have been put in place in Iowa, and final commission orders are expected for both cases during 2009.

Black Hills Energy – Nebraska Gas implemented a $1.8 million expansion of its automated meter reading system to include 25 Nebraska communities and approximately 13,000 additional customers.

Service Guard appliance repair and Technical Services provide added value to our utility customers while creating additional revenue. Because we provide these much-needed services throughout our rural service territories, we are able to maintain a more decentralized work force, in turn allowing us to more readily respond to the needs of our regulated utility customers.

[POSITIONING FOR THE FUTURE]

[NON-REGULATED ENERGY]

Our non-regulated energy businesses generate wholesale electricity, produce natural gas, coal and crude oil, and market energy. Our employees create value from the natural gas and oil fields to the burner tip and from the coal mine to the light switch.

[Power Generation]

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops and operates unregulated power plants. We hold varying interests in independent power plants operating in Wyoming and Idaho with a total net ownership of 141 megawatts as of Dec. 31, 2008. We also hold investment interests in power-related funds with a net ownership interest of 3 megawatts.

The divestiture of seven IPPs for more than replacement cost in July 2008 resulted in net income of $139.7 million and provided a tremendous opportunity to capture value for shareholders. This transaction demonstrated the strength of our IPP capabilities, and the proceeds allowed us to partially fund the Aquila acquisition, thus eliminating the need to issue equity. Despite this sale, we retain our strengths in planning, permitting, constructing and operating reliable and efficient power plants and will remain an active participant in the IPP business.

During January 2009, we completed the sale of a 23.5 percent interest in Wygen I to the Municipal Energy Agency of Nebraska for $51.0 million. We recognized a gain on the sale of approximately $16.7 million after tax. Concurrent with this sale, we also terminated a 10-year power purchase contract under which MEAN was obligated to buy 20 megawatts of power and capacity from Wygen I. The decreased revenues associated with the terminated agreement will be partially replaced by agreements under which MEAN will pay for costs associated with administrative services, plant operations and coal supplied by our coal mining operation.

[Oil and Gas]

After 10 years of continuously increasing production, Black Hills Exploration & Production's oil and natural gas production results were 7 percent lower in 2008 than 2007. Several factors contributed to this decline, including permit delays, reduced drilling spending and some limited production shut-ins due to low oil and natural gas prices. Additionally, commodity price declines at year-end 2008 combined with high industry service costs resulted in a reduction in year-end reserves and a non-cash fourth quarter ceiling test impairment of $59 million after tax.

Despite these year-end challenges with commodity prices, the drilling program yielded positive results in each of our three primary producing basins in the fourth quarter. Production was successful from the three newly-drilled wells in the Piceance Basin. Black Hills' newest horizontal drilling program in the Powder River Basin showed a positive test of more than 150 barrels of oil per day. Additionally, the Company had three successful shallow San Jose formation tests in the San Juan Basin with the average well producing greater than 500 thousand standard cubic feet per day.

[Energy Marketing]

Our Energy Marketing operations focus primarily on producer services and wholesale natural gas marketing. The business scope is composed of the purchase, sale, storage and transportation of natural gas and crude oil, as well as a variety of services including asset optimization, price risk management and customized offerings to producer and end-use clients.

As in previous years, prudent cash and risk management enabled Enserco, our energy marketing subsidiary, to complete the year with strong results while continuing to operate using its own stand-alone credit facility. The addition of more long-term transportation and storage contracts during 2008 has created significant value for 2009 and beyond. Our 2008 earnings were positively impacted at the end of the year by unrealized mark-to-market gains that accelerated margins into 2008 from proprietary positions that will not settle until 2009 and 2010.

[Coal Mining]

Our coal mining segment operates through our Wyodak Resources Development Corporation subsidiary. We mine and process low-sulfur coal at our coal mine near Gillette, Wyo. The coal mine was acquired in 1956 from Homestake Gold Mining Company and is in the Powder River Basin, which contains one of the largest coal reserves in the United States. In a basin characterized by thick coal seams, our overburden ratio, a comparison of the depth of material removed per foot of coal uncovered, has historically approximated a 1:1 ratio. In recent years, this has trended toward a 2:1 ratio, where it is expected to remain for the next several years.

Production primarily serves mine-mouth generation plants and select regional customers with long-term fuel needs. Total annual production increased 1.0 million tons in 2008, resulting in record production of 6.0 million tons, due to an increase in train load-out sales and sales to our new Wygen II power plant. We expect production to increase another 0.6 million tons per year to serve the needs of our Wygen III power plant when it comes online in mid 2010.

[POSITIONING FOR THE FUTURE]

[SERVICE COMPANY]

Black Hills Service Company consists of all the business support organizations, including finance and accounting, legal, communications, information technology, human resources, corporate development, investor relations, administration, regulatory and governmental affairs.

As we continue to work toward unifying our Company, the alignment of people, processes and systems are vital steps forward that will create efficiencies and a scalable platform for growth. We approach this next step of unification as an opportunity to embrace common values, align our efforts with a common set of goals, establish more effective processes, consolidate software systems and engage employees in the opportunities that surround them.

[PARTNERING WITH COMMUNITIES]

[COMMUNITIES]

We gauge our success based on the strength of our relationships. Our more than 2,100 employees are focused on creating value through the energy we provide and the products and services we deliver. Side by side, we work with more than 350 communities as a way of expressing our dedication to the areas in which we live and work. Our customers, regulators, shareholders, employees and neighbors count on us to demonstrate social, economic and environmental responsibility while improving life with energy. They trust that we will act responsibly and with integrity every day.

Our utility service areas are mostly rural, and most Black Hills employees live and work in the areas we serve. Our efforts are evident in various Company-sponsored programs, including Power of Trees and Weatherization.

Almost 500 employee volunteers from various divisions of Black Hills Corporation along with their 620 community partners donated and planted 668 new trees in 42 communities as part of the Power of Trees program. This community-impact program is designed to educate the public that everyone can do something to help beautify neighborhoods,

provide energy-saving shade and promote energy conservation. It is also a chance for us to educate the public about the Call Before You Dig and Right Tree in the Right Place programs.

Industry surveys show that when it comes to energy, cost and environmental impact are the top concerns of utility customers. To address these concerns, Black Hills introduced a companywide Weatherization program to educate people in our communities about simple actions they can take to control their own energy costs. An average home can be weatherized for about $100 and can generate savings for an individual homeowner of as much as 30 percent on their energy bills. This year, more than 320 employee volunteers and representatives from 11 partner organizations worked with local low-income assistance organizations to identify and weatherize more than 120 homes in 43 communities.

In addition, Black Hills employees volunteer their time, resources and energy in various civic and charitable organizations including United Way and our energy-assistance program, Black Hills ***Cares***.

We are a partner in the economic development efforts of our communities. Our initiatives and resources encourage existing companies to thrive and expand, and they focus on attracting new businesses that are in line with local planning and development goals. Our economic development professionals assist hundreds of communities with a variety of project proposals, business development activities, community infrastructure planning, organizational development and innovative, cost-effective energy solutions.

Our Regulatory and Governmental Affairs group is focused on achieving the regulatory and legislative successes necessary to provide us with opportunities to earn fair rates of return on our investments. This group advocates for responsible legislative and regulatory actions that fully consider the customer and business impacts. Reputation, trust and commitment to the best overall outcome provide the opportunity for this group to be successful.

[We respect each other.
Our unique talents and diversity anchor a culture of success.]

RESPECT

[PARTNERING WITH COMMUNITIES]

[EMPLOYEES]

Fully engaged employees are fundamental to our success, and our vision, mission and values serve as focal points to align our efforts. The expertise and dedication of our more than 2,100 employees are essential to providing our products and services. Employees are encouraged to continuously expand their knowledge and skills and be involved in serving their communities. In return, employees share their talents to accomplish our goals, deliver financial results and serve our customers.

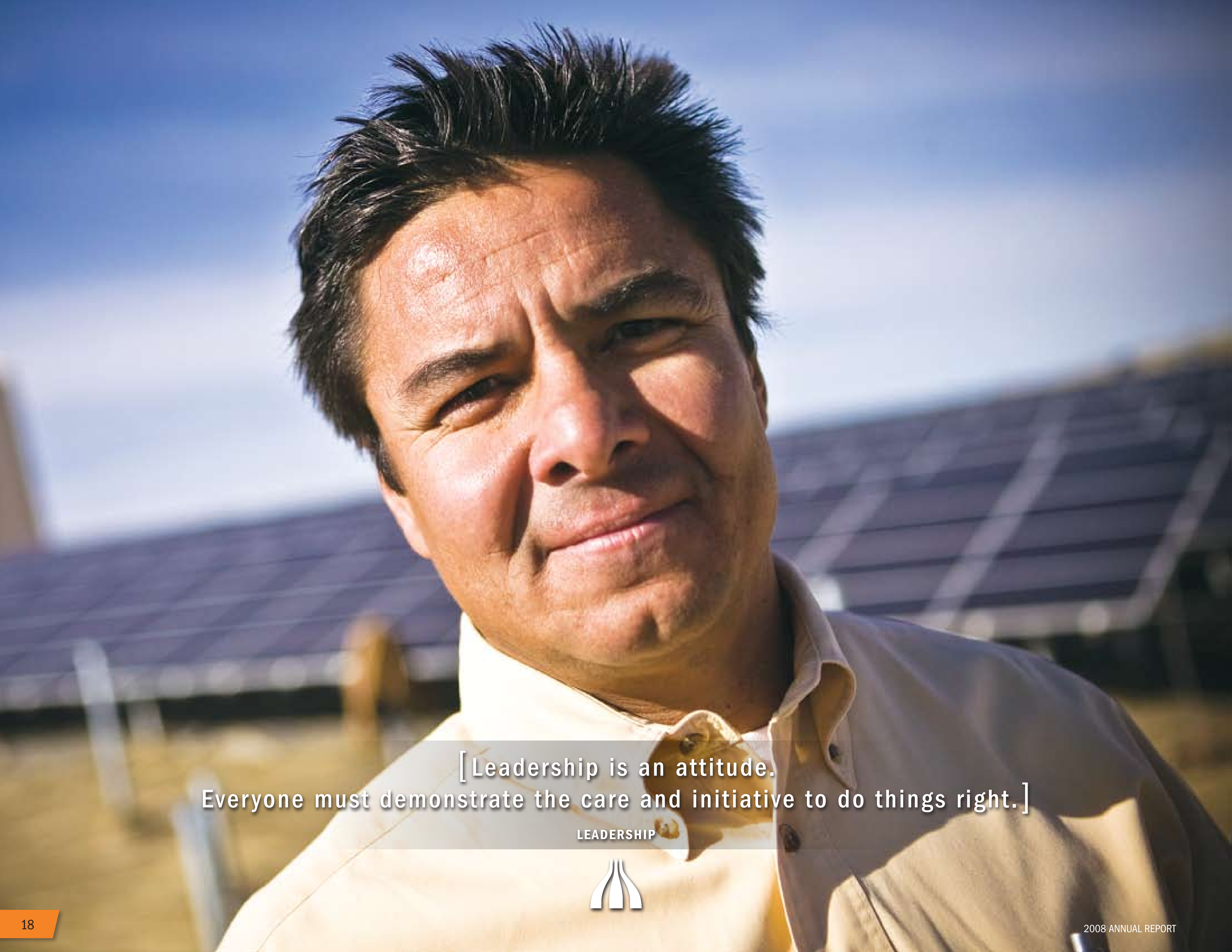
After the Aquila acquisition, our employee base more than doubled. As a result, the Company's vision, mission and values were updated to encompass and reflect the "new" and larger Black Hills Corporation family.

To anchor our newly transformed Company and provide a common foundation for the future, corporate officers traveled throughout the businesses to talk with employees about our vision, mission and values (referred to as "VMV" by employees). Employees wore T-shirts that displayed the value they connect with the most. Employees continue to incorporate the Company's VMV in their daily efforts, such as the statewide value T-shirt day initiated by Nebraska employees as a follow up to the VMV discussions.

Various safety programs and initiatives throughout the Company promote and maintain the safety of our employees and communities.

Employees emphasize a safe work environment through numerous safety committees, monthly meetings and community outreach efforts. Black Hills Power and Cheyenne Light, Fuel & Power have established Safety Council committees, which include a diverse group of management, linemen and office employees who volunteer their time during monthly safety brainstorming sessions. In addition, field employees for Black Hills Energy's natural gas and electric operations meet at least once a month with management to discuss safety issues.

For about 25 years, Black Hills Energy employees have provided community volunteer firefighters the opportunity to practice techniques to effectively contain and extinguish actual natural gas fueled fires under controlled circumstances. Because natural gas fires are rare, the training sessions provide hands-on experience so firefighters know how to fight this type of fire.


[Leadership is an attitude.
Everyone must demonstrate the care and initiative to do things right.]
LEADERSHIP

[PARTNERING WITH COMMUNITIES]

[ENVIRONMENT]

As part of Black Hills Corporation's commitment to our communities, we are continuously working to expand our renewable energy supply portfolio at reasonable rates for our customers. In 2008, the Company continued this commitment with several programs developed to push us to the forefront of environmental stewardship.

Black Hills Energy – Colorado Electric recognizes customers' commitment to energy efficiency through its successful solar rebate program. In its third full year, the program provides customers who install their own on-site solar electricity systems with incremental savings on installation costs. The program also compensates them at years-end based on the amount of solar electricity generated by their system – in excess of their consumption.

In Cañon City, Colo., Black Hills Energy's power facility uses forest waste as a generating fuel, reducing the amount of pollutants such as sulfur oxides and nitrogen oxides for that plant. The project involves mixing coal with small amounts of wood culled from fire-prone forests on Colorado's Front Range. Black Hills Energy now joins the ranks of more than a dozen U.S. utilities that have experience cofiring biomass with coal.

Cheyenne Light, Fuel & Power, in partnership with Duke Energy, dedicated a 750-acre Happy Jack Wind Farm in September 2008. Cheyenne Light has a power purchase agreement in place to purchase all of the electricity generated at the wind farm for the next 20 years from Duke Energy, which owns the turbines. The facility's 14 wind turbines are designed to generate nearly 30 megawatts of power – enough to power several thousand homes. The power generated by those turbines helps power the homes and businesses of Black Hills Power and Cheyenne Light customers.

We pride ourselves on providing tips, tools and services to our customers aimed at reducing energy use and providing cost-saving opportunities. This is accomplished through energy-efficiency education on Web sites, in customer communications and through community events.

Black Hills Corporation has been improving life with energy to customers and communities for the past 125 years and will continue to do so for the next 125 years and beyond.

[VISION – BE THE ENERGY PARTNER OF CHOICE.]

[MISSION – IMPROVING LIFE WITH ENERGY.]

[VALUES]

AGILITY
We embrace change and challenge ourselves to adapt quickly to opportunities.

COMMUNICATIONS
Consistent, open and timely communication keeps us focused on our strategy and goals.

CREATING VALUE
We are committed to creating exceptional value for our shareholders, employees,customers and the communities we serve ... always.

CUSTOMER SERVICE
We are committed to providing a superior customer experience every day.

INTEGRITY
We hold ourselves to the highest standards based on a foundation of unquestionable ethics.

LEADERSHIP
Leadership is an attitude. Everyone must demonstrate the care and initiative to do things right.

PARTNERSHIP
Our partnerships with shareholders, communities, regulators, customers and each other make us all stronger.

RESPECT
We respect each other. Our unique talents and diversity anchor a culture of success.

[POSITIONING FOR THE FUTURE]

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GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

Acquisition Facility	Our $1.0 billion single-draw, senior unsecured facility from which a $383 million draw was used to provide part of the funding for our Aquila Transaction
AFUDC	Allowance for Funds Used During Construction
Aquila	Aquila, Inc.
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila
ARO	Asset Retirement Obligations
Basin Electric	Basin Electric Power Cooperative
Bbl	Barrel
Bcfe	Billion cubic feet equivalent
BHCCP	Black Hills Corporation Credit Policy
BHCRPP	Black Hills Corporation Risk Policies and Procedures
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
BHER	Black Hills Energy Resources, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Corporation Plan	Black Hills Corporation Retirement Savings Plan
Black Hills Energy	The name used to conduct the business of Black Hills Utility Holdings, Inc. including the gas and electric utility properties acquired from Aquila
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of the Company that was formerly known as Black Hills Energy, Inc.
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of the Company formed to acquire and own the utility properties acquired from Aquila, all which are now doing business as Black Hills Energy
Black Hills Wyoming	Black Hills Wyoming, Inc., a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company
Cheyenne Light Pension Plan	The Cheyenne Light, Fuel and Power Company Pension Plan
Cheyenne Light Plan	Cheyenne Light, Fuel and Power Company Retirement Savings Plan
CO_2	Carbon Dioxide
Colorado Electric	Black Hills Colorado Electric Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Colorado electric utility properties acquired from Aquila
Colorado Gas	Black Hills Colorado Gas Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Colorado gas utility properties acquired from Aquila
CPUC	Colorado Public Utilities Commission
CT	Combustion turbine
Dth	Dekatherms
Enserco	Enserco Energy Inc., a wholly-owned subsidiary of Black Hills Non-regulated Holdings
Enserco Facility	The $300 million uncommitted, secured line of credit that supports Enserco's marketing and trading operations, which currently expires May 8, 2009
EPA 2005	Energy Policy Act of 2005
ERISA	Employee Retirement Income Security Act
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
Fortis	Fortis Capital Group
GAAP	Accounting principles generally accepted in the United States
GCA	Gas Cost Adjustment
Great Plains	Great Plains Energy Incorporated
Hastings	Hastings Fund Management Ltd
IGCC	Integrated Gasification Combined Cycle

IIF	IIF BH Investment LLC, a subsidiary of an investment entity advised by JPMorgan Asset Management
Indeck	Indeck Capital, Inc.
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC, (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Iowa gas utility properties acquired from Aquila
IPP	Independent Power Production
IPP Transaction	The July 11, 2008 sale of seven of our IPP plants to affiliates of Hastings and IIF
IRS	Internal Revenue Service
IUB	Iowa Utilities Board
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Kansas gas utility properties acquired from Aquila
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Las Vegas II	Las Vegas II gas-fired power plant
MAPP	Mid-Continent Area Power Pool
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent
MDU	Montana Dakota Utilities Co., a public utility division of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
Moody's	Moody's Investors Service, Inc.
MW	Megawatts
MWh	Megawatt-hours
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Nebraska gas utility properties acquired from Aquila
NYMEX	New York Mercantile Exchange
PCA	Power Cost Adjustment
PGA	Purchase Gas Adjustment
PSCo	Public Service Company of Colorado
SEC	U. S. Securities and Exchange Commission
S&P	Standard & Poor's, a division of The McGraw-Hill Companies, Inc.
Valencia	Valencia Power, LLC, a former subsidiary of Black Hills Non-regulated Holdings that was sold as part of our IPP Transaction
VIE	Variable Interest Entity
WECC	Western Electricity Coordinating Council
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corporation, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

ACCOUNTING PRONOUNCEMENTS

ARB	Accounting Research Bulletin
ARB No. 51	ARB No. 51, "Consolidated Financial Statements"
EITF	Emerging Issues Task Force
EITF 04-6	EITF Issue No. 04-6, "Accounting for Stripping Costs Incurred during Production in the Mining Industry"
EITF 87-24	EITF 87-24, "Allocation of Interest to Discontinued Operations"
EITF 91-6	EITF No. 91-6, "Revenue Recognition of Long-Term Power Sales Contracts"
EITF 99-19	EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent"
EITF 02-3	EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities"
FIN 39	FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts – an Interpretation of APB Opinion No. 10 and FASB Statement No. 105"
FIN 46(R)	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities Revised"
FIN 48	FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement 109"
FSP	FASB Staff Position
FSP FAS 157-1	FSP FAS 157-1, "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements that Address Fair Value Measurement for Purposes of Lease Classification or Measurement under Statement 13"
FSP FAS 157-2	FSP FAS 157-2, "Effective Date of FASB Statement No. 157"
FSP FIN 39-1	FSP FIN 39-1, "Amendment of FASB Interpretation No. 39"
SEC Final Rule #33-8995	Modernization of Oil and Gas Reporting

SFAS	Statement of Financial Accounting Standards
SFAS 13	SFAS 13, "Accounting for Leases"
SFAS 69	SFAS 69, "Disclosures about Oil and Gas Producing Activities – an amendment of FASB Statements 19, 25, 33 and 39"
SFAS 71	SFAS 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS 87, "Employers' Accounting for Pensions"
SFAS 109	SFAS 109, "Accounting for Income Taxes"
SFAS 123(R)	SFAS 123 (Revised 2004), "Share-Based Payment"
SFAS 132(R)	SFAS 132(R), "Employer's Disclosures about Pensions and Other Postretirement Benefits – an amendment of FASB Statements No. 87, 88 and 106"
SFAS 133	SFAS 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 141(R)	SFAS 141 (Revised 2007), "Business Combinations"
SFAS 142	SFAS 142, "Goodwill and Other Intangible Assets"
SFAS 143	SFAS 143, "Accounting for Asset Retirement Obligations"
SFAS 144	SFAS 144, "Accounting for the Impairment of Long-lived Assets"
SFAS 157	SFAS 157, "Fair Value Measurements"
SFAS 158	SFAS 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of FASB Statements No. 87, 88, 106 and 132(R)"
SFAS 159	SFAS 159, "The Fair Value Option for Financial Assets and Financial Liabilities"
SFAS 160	SFAS 160, "Non-controlling Interest in Consolidated Financial Statements – an amendment of ARB No. 51"
SFAS 161	SFAS 161,"Disclosure about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133"

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS AND QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are an integrated energy company operating principally in the United States with two major business groups – Utilities and Non-regulated Energy. We report for our business groups in the following financial segments:

Business Group	Financial Segment
Utilities	Electric Utilities
	Gas Utilities
Non-regulated Energy	Oil and Gas
	Power Generation
	Coal Mining
	Energy Marketing

Our Utilities Group consists of our Electric and Gas utility segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 202,100 customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light and its approximately 33,300 gas utility customers in Wyoming. Our Gas Utilities segment serves approximately 524,000 natural gas customers in Colorado, Nebraska, Iowa and Kansas. Our Non-regulated Energy Group engages in the production of coal, natural gas and crude oil primarily in the Rocky Mountain region; the production of electric power through ownership of a portfolio of generating plants and the sale of electric power and capacity primarily under long-term contracts; and the marketing of natural gas, crude oil and related services.

Industry Overview

The United States energy industry experienced one of the most tumultuous years ever in 2008. Energy commodity prices, which were near historic highs in July with natural gas trading over $13 per Mcf and crude oil selling for nearly $150 per barrel, experienced dramatic declines to less than $6 and $45, respectively, by year end. Domestic energy prices continue to be influenced by global factors, including foreign economic conditions, especially in China and Asia, domestic economic conditions, the policies of OPEC and other large foreign oil producers, and political tensions and conflict in many regions. Mild weather dominated the United States during much of the year, reducing demand for fuel used for power generation and heating.

Beginning in late summer, a slow down in the United States economy accelerated into one of the worst recessions since the 1930s. A global credit crisis emerged from a proliferation of sub-prime lending. As that issue attracted attention, other credit quality concerns surfaced, creating an international-scale financial crisis. The capital markets have been impacted dramatically by the crisis, severely inhibiting the ability of companies to raise both debt and equity capital, and significantly increasing the cost of capital.

Like other United States industries, the energy industry is faced with uncertainties, both short and long-term. Many utilities are faced with large capital spending needs over the next few years to replace aging infrastructure and add new assets such as transmission lines and renewable energy resources. Utility companies generally are less impacted by economic downturns, but a prolonged or severe recession could affect the demand for energy services and the ability of customers to pay their utility bills and restrict the ability of companies to obtain the capital necessary for infrastructure expansion.

The federal and state utility regulatory climate in 2008, in a general sense, remained relatively constructive among government, industry and consumer representatives. In the multi-state region encompassing our utility operations, regulators were willing to establish rates based on multi-year considerations, including fuel and other reasonable cost adjustments, justifiable capital expenditures for maintenance and expansion of energy systems, and a response to environmental concerns through demand management and energy efficiency programs.

The November 2008 elections however, represented a significant change in the domestic political environment. Sweeping wins for Democrats in both Houses of Congress, signal a shift in domestic policy that will likely have dramatic impacts on the domestic energy industry. Despite all of the focus on the economy, environmental issues are slated to remain a priority for many in Congress. Federal legislation that would mandate renewable energy use and the reduction of greenhouse gas emissions appears likely to pass during this Congress in the form of a federal renewable portfolio standard, and a greenhouse gas reduction target, utilizing either a carbon tax or a carbon "cap-and-trade" system. These potential legislative actions could have significant macroeconomic consequences. The associated cost increase may cause a dramatic increase in consumers' rates for electricity and other energy in the mid- to long-term. State legislatures were also active on environmental issues in 2008, with a majority of states now having adopted some form of renewable standard, including some in which we operate. In addition, several states have passed greenhouse gas emissions legislation.

Progress in the domestic energy industry in 2008 included increasing levels of oil and gas exploration and production activity, continued planning and construction of liquefied natural gas port facilities, proposals for additional gas-fired, coal-fired and nuclear power plants, planning for additional electric transmission capacity, and the advancement of renewable energy resources and utilization.

The energy industry continues to adjust to change, including the trends of consolidation in the electric and gas utility sectors, along with asset divestitures to restrict or redefine business strategies. The energy marketplace continues to respond to increased oversight and enforcement activity of the FERC and increased environmental and emissions reviews and mandates. In recent years, several state regulatory agencies allowed electric utilities to construct and operate power plants in vertically integrated structures after years of discouraging or prohibiting such activity.

Over the last several years, the corporate structure of many energy companies underwent evaluation and change, in large part due to efforts to create additional shareholder value. A number of companies are contemplating or implementing a realignment of business lines, reflecting a shift in long-term strategies. Some are divesting certain energy properties to focus on core businesses, such as exiting unregulated power production or oil and gas production in favor of more stable utility operations. Others have engaged in mergers and acquisitions with a goal to improve economies of scale and returns to investors. Private equity investors continued to play a role in the changing composition of energy ownership, but to a lesser extent than previous years.

Many industry analysts have cited the need for expanded energy capacity and delivery systems. They foresee an increase in capital investment across a wide spectrum of energy companies. Many electric and gas utilities must replace aging plant and equipment, and regulators appear to be willing to provide acceptable rate treatment for additional utility investment. Oil and gas producers will continue to explore for new reserves, particularly of natural gas, which will be the primary fuel of choice in an era of concern regarding greenhouse gas emissions. In the short-term, however, low oil and natural gas prices prompted companies to curtail projects as they seek to conserve cash in a constrained capital market environment. The increased focus on environmental regulation has made it increasingly more difficult to obtain drilling permits, particularly on public and Native American lands.

In early 2008, the domestic coal industry benefited from a positive price environment, in large part due to high and volatile natural gas prices. Coal prices have moderated considerably in response to a trend of lower overall natural gas prices. Fossil fuel combustion continues to be a contentious domestic and international public policy issue, as many nations, including United States allies, advocate reductions in CO_2 and other emissions. Many states now encourage the energy industry to invest in renewable energy resources, such as wind or solar power, or the use of bio-mass as a fuel. In many instances, renewable energy use is mandated by state regulators. Furthermore, the State of California has mandated that future imports of power must come from power plants with lower emission levels than currently associated with conventional coal-fired plants. Such restrictions may alter transmission flow of power in western states, as a large percentage of current power generation in the western grid comes from coal sources.

The power generation industry continues to make improvements in emissions control in response to regulatory mandates. Emissions from new coal-fired plants are a small fraction of those produced by power plants built a generation ago. Along with similar technological progress, coal can and likely will remain an important, domestically available, and economical national energy resource that is vital to meet growing energy demand. In that regard, the United States Department of Energy is beginning to take positive steps toward ensuring the future of coal through research funding for “clean coal” technologies and methods of carbon capture and sequestration.

Energy providers, government authorities and private interests continue to address issues concerning electric transmission, power generation capacity, the use of renewable and other diversified sources of energy, oil and natural gas pipelines and storage, and other infrastructure requirements. In the short-term, prevailing economic conditions will reduce consumption. Despite public and private efforts to promote conservation and efficiency, however, the demand for energy is expected to increase steadily over the long term. To meet this demand growth, the industry will need to provide capital, resources and innovation to serve customers in cost-effective ways and to achieve suitable returns on investment.

The Company believes that it is well-positioned in this industry setting, and able to proceed with its key business objectives. Along with industry counterparts, we are preparing to address the challenges discussed in this overview, such as new environmental mandates, renewable portfolio standards, carbon-related taxes or trading systems, credit market conditions, inflation, or other factors that may affect energy demand and supply. In particular, we are sensitive to additional costs that can negatively affect our customers or our profitability. To that end, we intend to work closely with regulators and industry leaders to assure that cost-conscious proposals and solutions are carefully explored in public policy proceedings.

Business Strategy

We are a customer-focused integrated energy company. Our business is comprised of electric and natural gas utility operations; power generation; and fuel assets and services, including production and marketing operations for crude oil, natural gas and coal. Our focus on customers – whether they are utility customers or non-regulated generation, fuel or marketing customers – provides opportunities to expand our businesses. Our balanced, integrated approach to the energy business is supported by disciplined risk management practices.

The diversity of our energy operations, which range from fuel production to retail utility sales, reduces reliance on any single business segment to achieve our strategic objectives. It helps reduce our overall corporate risk and enhances our ability to earn stronger returns for shareholders over the long term. Despite very challenging conditions in the capital markets, we have sufficient liquidity and solid cash flows, and expect to be able to access the capital markets as needed. Consequently, our financial foundation is sound and capable of supporting an expansion of operations in both the near and long term.

During 2008, we significantly transformed our business and reduced our risk profile through the acquisition of five utility properties, and the divestiture of seven IPP plants. For the next two years, we will focus on continued integration of the newly acquired utility properties and the achievement of certain synergies made possible by the utility acquisition. We expect to achieve operating synergies in accounting and information systems, procurement, inventory, utility engineering, power marketing, resource planning and other areas.

Our long-term strategy focuses on growing both our utility and non-regulated energy businesses, primarily by increasing our customer base and providing superior service to both utility and non-regulated energy customers.

In our natural gas and electric utilities, we intend to grow our asset base through customer growth in our existing utility service territories, combined with the construction of new rate-based power generation facilities. We also plan to pursue acquisitions of additional utility properties, primarily in the Great Plains and Rocky Mountain regions of the country. By maintaining our high customer service and reliability standards in a cost-efficient manner, our goal is to secure satisfactory rate recovery to provide solid economic returns on our utility investments.

In our fuel production operations, we will continue to prudently grow and develop our existing inventory of oil and gas reserves, while we strive to maintain our positive relationships with mineral owners, landowners and regulatory authorities. Our ability to grow both production and reserves may be hindered in the short-term by low price levels for both crude oil and natural gas resulting from the impact on demand of a weakened economy. In the long-term, however, we believe that demand for natural gas will be strong. Given increased regulatory emphasis on wind and solar power generation, and potential greenhouse gas legislation that may limit construction of new coal-fired power plants, natural gas will be the fuel of choice for power generation. Additional gas-fired peaking resources will also be necessary to provide back-up supply for renewable technologies.

We will continue efforts to develop additional markets for our coal production, including the development of additional power plants at our mine site. Nearly 50% of all electricity generated in the United States is currently supplied from coal-fired plants, and it will take decades before this generation can be replaced with alternative technologies. As a result, coal-fired resources will remain a necessary component of the nation's electric supply for the foreseeable future. Potential greenhouse gas legislation may limit construction of new conventional coal-fired power plants, but technologies such as carbon capture and sequestration should provide for the long-term economic use of coal. We will investigate the possible deployment of these technologies at our mine site in Wyoming.

We divested of seven IPP plants in 2008 because we were able to capture significant value for shareholders, but we are not exiting the non-regulated power generation business. We have expertise in permitting, constructing and operating power generation facilities; and these skills provide us with a key opportunity to add long-term shareholder value. We intend to grow our non-regulated power generation business by continuing to focus on long-term contractual relationships with other load-serving utilities.

The expertise of our energy marketing business should provide continued profitability through a risk-managed and disciplined approach to producer services, origination, storage, transportation and proprietary marketing strategies. We will also continue to utilize our marketing expertise to enhance the value of our other energy assets, particularly our fuel and power generation assets.

We intend to operate our lines of business as Utilities and Non-regulated Energy Groups. The Utilities Group consists of electric and natural gas utility assets and services. The Non-regulated Energy Group consists of fuel production, mid-stream assets, power generation facilities and energy marketing.

The following are key elements of our business strategy:

- Complete the full, efficient integration of the five utility properties acquired in the 2008 Aquila Transaction, focusing on the achievement of operating synergies and cost reductions;
- Provide stable long-term rates for customers and increase earnings by efficiently planning, constructing and operating rate-base power generation facilities needed to serve our electric utilities;
- Proactively integrate alternative and renewable energy into our utility energy supply while remaining mindful of potential customer rate impacts;
- Expand utility operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages;
- Build and maintain strong relationships with wholesale power customers of both our utilities and non-regulated power generation businesses;
- Selectively grow our non-regulated power generation business in targeted Western markets by developing assets and selling most of the capacity and energy production through mid-and long-term contracts primarily to load-serving utilities;
- Exploit our fuel cost advantages and our operating and marketing expertise to produce and sell power at attractive margins;
- Grow our reserves and increase our production of natural gas and crude oil in a cost-effective manner;
- Opportunistically expand our energy marketing operations including producer and end-use origination services and, as warranted by market conditions, natural gas and crude oil storage and transportation opportunities;
- Diligently manage the credit, price and operational risks inherent in buying and selling energy commodities; and
- Maintain an investment grade credit rating and ready access to debt and equity capital markets.

Complete the full, efficient integration of the five utility properties acquired in the 2008 Aquila Transaction, focusing on the achievement of operating synergies and cost reductions. The July 14, 2008 acquisition of five utility properties in four states from Aquila significantly expanded our regional presence and the size and scope of our utility operations. The expanded utility operations will enhance our ability to serve customers and communities and build long-term value for our shareholders. Over the next two years, we will continue working diligently to integrate the operations of the five acquired utilities with our other utility operations. By standardizing processes, centralizing purchasing and inventory, and utilizing common computer systems for customer service, accounting, human resources and operations, it will be possible to reduce costs and improve operating efficiency.

Provide stable long-term rates for customers and increase earnings by efficiently planning, constructing and operating rate-base power generation facilities needed to serve our electric utilities. Our Company was originally a vertically integrated electric utility. This business model remains a core strength and strategy today, where we invest in and operate efficient power generation resources to transmit and distribute electricity to our customers. We provide power at reasonable and stable rates to our customers and earn competitive returns for our investors. Rate-based generation assets offer several advantages for consumers, regulators and investors. First, the assets assure consumers that rates have been reviewed and approved by government authorities who safeguard the public interest. Since the generating assets are included in the utility rate base, customer rates are more stable than if the power was purchased from the open market via wholesale contracts. Second, regulators participate in a planning process where long-term investments are designed to match long-term energy demand. Third, investors are assured that a long-term, reasonable, stable rate of return may be earned on their investment. A lower risk profile may also improve credit ratings which, in turn, can benefit both consumers and investors by lowering our cost of capital.

Examples of our progress include the January 2008 completion of Wygen II to serve the customers of Cheyenne Light and the ongoing construction of Wygen III to serve the customers of Black Hills Power. In August 2008, following the closing of the Aquila Transaction, we submitted to the Colorado regulators a long-term resource plan that included the proposed construction of up to five gas-fired power plants, with a total capacity of approximately 350 megawatts, to serve the customers of Colorado Electric. Hearings were completed in late January 2009, and on February 24, 2009 the Commission issued its initial decision. The decision allows us to construct 2 gas-fired power plants representing approximately 150 MW. We will issue a request for proposal for the remaining 200 MW with a bid due date in June 2009. Under the process outlined by the Commission in its decision, we may submit proposals to provide generation through our IPP business. This initial Commission decision and order is subject to requests by any party to the proceeding for reconsideration by the Commission, which must be filed by March 16, 2009.

Proactively integrate alternative and renewable energy into our utility energy supply while remaining mindful of potential customer rate impacts. The energy and utility industries face tremendous uncertainty related to the potential impact of legislation intended to reduce greenhouse gas emissions and increase the use of renewable and other alternative energy sources. To date, many states have enacted and others are considering some form of mandatory renewable energy standard requiring utilities to meet certain thresholds of renewable energy use. Additionally, many states have either enacted or are considering legislation setting greenhouse gas emissions reduction targets. Federal legislation for both renewable energy standards and greenhouse gas emission reductions is also under consideration.

Mandates for the use of renewable energy or the reduction of greenhouse gas emissions will likely result in substantial increases in the prices for electricity and natural gas. At the same time, however, as a regulated utility we are responsible for providing safe, reasonably priced, reliable sources of energy to our customers. As a result, we have developed a customer-centered strategy for renewable energy standards and greenhouse gas emission reductions that balances our customers' rate concerns with environmental considerations. We attempt to strike this balance by prudently and proactively incorporating renewable energy into our resource supply, while seeking to minimize rate increases for our utility customers. Examples of our balanced approach include:

- With respect to states such as South Dakota and Wyoming that currently have no legislative mandate on the use of renewable energy, we have nevertheless integrated cost-effective renewable energy into our generation supply on the expectation that there will be mandatory renewable energy standards in the future. For example, in September 2008, we commenced buying wind energy for use at Black Hills Power and Cheyenne Light under a 20-year power purchase agreement for approximately 30 MW of wind energy located in Cheyenne, Wyoming;

- In states such as Colorado and Montana that do have a legislative mandate on the use of renewable energy, we are aggressively pursuing cost-effective initiatives with the regulators that will allow us to accomplish our renewable energy requirements. In Colorado for instance, we recently filed an electric resource plan that includes enough renewable energy additions and greenhouse gas emission reductions to permit us to satisfy both (i) the State's requirement that 20% of a utility's distributed energy must be supplied by renewable energy resources by 2020 and (ii) the governor's executive order that requires a 20% reduction in carbon dioxide emissions; and

- In all states in which we conduct electric operations, we are exploring other potential biomass, solar and wind energy projects and evaluating other potential wind generator sites, particularly sites located near our utility service territories.

Using reasonable assumptions, we have also carefully evaluated our coal-fired generating facilities and the potential future economic impact of a carbon tax or cap-and-trade regime intended to reduce CO_2 emissions. For customers in states without renewable or CO_2 mandates, such as South Dakota and Wyoming, we believe it is still in our utility customers' long-term interest to construct new mine-mouth, coal-fired generating facilities, such as our Wygen II generation facility (completed in January 2008) and our Wygen III generation facility (under construction). In addition, we are actively evaluating alternative coal-fired generation technologies, including IGCC and carbon capture and sequestration, though both appear cost prohibitive in the near term. These technologies may become cost effective in the future if the cost of CO_2 emissions reaches sufficiently high levels or further technological advancements reduce the costs of those technologies.

Expand utility operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages. For 125 years, we have provided strong utility services, delivering quality and value to our customers. Our tradition of accomplishment supports efforts to expand our utility operations into other markets, most likely in the Midwest, West and possibly other regions that permit us to take advantage of our intrinsic competitive advantages, such as baseload power generation, system reliability, superior customer service, community involvement and a relationship-based approach to regulatory matters. The 2005 acquisition of Cheyenne Light and the 2008 Aquila Transaction are examples of such expansion efforts. Utility operations also enhance other important business development, including gas transmission pipelines and storage infrastructure, which could promote other non-regulated energy operations. Utility operations can contribute substantially to the stability of our long-term cash flows, earnings and dividend policy.

Although we do not expect to make any significant utility acquisitions in 2009, some industry experts believe that the current financial turmoil and economic recession may produce opportunities for healthy utility companies to acquire utility assets and operations of less creditworthy companies upon attractive terms and conditions. We would expect to consider such opportunities if we believe they would further our long-term strategy and help maximize shareholder value.

Build and maintain strong relationships with wholesale power customers of both our utilities and non-regulated power generation business. We strive to build strong relationships with other utilities, municipalities and wholesale customers and believe we will continue to be a primary provider of electricity to wholesale utility customers. We further believe that these entities will need products, such as capacity, in order to serve their customers reliably. By providing these products under long-term contracts, we are able to help our customers' meet their energy needs. Through this approach, we also believe we can earn more stable revenues and greater returns over the long term than we could by selling energy into more volatile spot markets. In addition, relationships that we've established with wholesale power customers have developed into other opportunities. MEAN and MDU, both wholesale power customers, will now also be our joint owners in power plants.

Selectively grow our non-regulated power generation business in targeted Western markets by developing assets and selling most of the capacity and energy production through mid- and long-term contracts primarily to load-serving utilities. In late 2007, we initiated an evaluation of the merits of divesting certain power generation assets. That strategic review resulted in the mid-2008 divestiture of seven IPP plants for a total of $840 million. While much of our recent power plant development has been for our regulated utilities, we intend to continue to expand our non-regulated power generation business by developing and operating power plants in regional markets based on prevailing supply and demand fundamentals in a manner that complements our existing fuel assets, and marketing capabilities. We intend to grow this business through a combination of disciplined acquisitions and the development of new power generation facilities primarily in the western region where our detailed knowledge of market and electric transmission fundamentals gives us a competitive advantage, and, in turn, increases our ability to earn attractive returns. We expect to prioritize small-scale facilities that serve incremental growth, and are relatively easier to permit and construct than large-scale generation projects.

Most of the energy and capacity from our non-regulated power facilities is sold under mid- and long-term contracts. By doing so, we believe that we can satisfy the requirements of our customers while earning more stable revenues and greater returns over the long term than we could by selling our energy into the more volatile spot markets. When possible, we structure long-term contracts as tolling arrangements, whereby the contract counterparty assumes the fuel risk. Going forward, we will continue to focus on selling a majority of our unregulated capacity and energy primarily to load-serving utilities under long-term agreements that have been reviewed or approved by state utility commissions.

With respect to our current power sale agreements, two of our long-term power contracts expire in 2011 and 2013. These contracts provide for the sale of capacity and energy to Cheyenne Light from our Gillette CT and Wygen I plants, respectively. As part of our integrated resource planning efforts, a decision will be made regarding whether or not to extend or replace the contracts. In anticipation of renewal or extension, a contract review process generally begins about two years in advance of expiration, and we would expect to proceed accordingly.

Exploit our fuel cost advantages and our operating and marketing expertise to produce and sell power at attractive margins. We expect to selectively expand our portfolio of power plants which have relatively low marginal costs of producing energy and related products and services. We intend to utilize a competitive power production strategy, together with access to coal and natural gas reserves, to be competitive as a power generator. Competitive production costs can result from a variety of factors, including low fuel costs, efficiency in converting fuel into energy, and low per unit operation and maintenance costs. In addition, we typically operate our plants with high levels of availability, as compared to industry benchmarks. We aggressively manage each of these factors with the goal of achieving low production costs.

One of our primary competitive advantages is our WRDC coal mine, which is located in reasonably close proximity to our electric utility service territories. We attempt to exploit this competitive advantage by building additional mine-mouth coal-fired generating capacity, which allows us to substantially eliminate fuel transportation and storage costs. This strengthens our position as a low-cost producer because transportation costs often represent the largest component of the delivered cost of coal for many other utilities.

Grow our reserves and increase our production of natural gas and crude oil in a cost-effective manner. Our strategy is to cost- effectively grow our reserves and increase our production of natural gas and crude oil through both organic growth and acquisitions. While consistent growth remains our objective, we realize the necessity of managing for value over managing for growth and intend to be appropriately responsive to market conditions. Growth in our core areas in the Rocky Mountain region is a focus that we must balance with opportunities in plays or basins which are new to us. In the short-term, growth plans may be negatively impacted by the current economic crisis, and low crude oil and natural gas prices. In the long-term, however, we believe that demand will lead to higher product prices and opportunity for growth.

Specifically, we plan to:

- Primarily focus on lower-risk development and exploratory drilling;
- Participate on a non-operated basis with other operators to provide exposure to additional plays and producing basins;
- Focus on various plays in the Rocky Mountain region, where we can more easily integrate with our existing oil and natural gas operations as well as our fuel marketing and/or power generation activities;
- Support the future capital requirements of our drilling program by stabilizing cash flows with a hedging program that mitigates commodity price risk for a substantial portion of our established production for up to 2 years in the future; and
- Enhance our oil and gas production activities with the construction or acquisition of mid-stream gathering, compression and treating systems in a manner that maximizes the economic value of our operations.

Opportunistically expand our energy marketing operations including producer and end-use origination services and, as warranted by market conditions, natural gas and crude oil storage and transportation opportunities. Our energy marketing business seeks to provide services to producers and end-users of natural gas and crude oil and to capitalize on market volatility by employing storage, transportation and proprietary trading strategies. The service provider focus of our energy marketing activities largely differentiates us from other energy marketers. Through our producer services group, we assist mostly small- to medium-sized producers throughout the Western United States with marketing and transporting their crude oil and natural gas. Through our origination services, we work with utilities, municipalities and industrial users of natural gas to provide customized delivery services, as well as to support their efforts to optimize their transportation and storage positions.

Diligently manage the credit, price and operational risks inherent in buying and selling energy commodities. All of our operations require effective management of counterparty credit risk. We mitigate this risk by conducting business with a diversified group of creditworthy counterparties. In certain cases where creditworthiness merits security, we require prepayment, secured letters of credit or other forms of financial collateral. We establish counterparty credit limits and employ continuous credit monitoring with regular review of compliance under our credit policy by our Executive Credit Committee. Our oil and gas, power generation and energy marketing operations require effective management of price and operational risks related to adverse changes in commodity prices and the volatility and liquidity of the commodity markets. To mitigate these risks, we have implemented risk management policies and procedures, particularly for our marketing operations. We have oversight committees that monitor compliance with our policies. We also limit exposure to energy marketing risks by maintaining a credit facility separate from our corporate facility. We had no counterparty credit losses in 2008 despite the economic turmoil.

Maintain an investment grade credit rating and ready access to debt and equity capital markets. Access to capital will be critical to our future success. We will require access to the capital markets to fund our planned capital investments or, when possible, to make strategic acquisitions that prudently grow our businesses.

In 2008, disruption in worldwide capital markets was evidenced by diminished liquidity in the debt capital markets, significant write-offs in the financial services sector, the re-pricing of credit risk, and the failure of certain financial institutions. Despite actions of the United States federal government, these events have contributed to a general economic decline that is materially and adversely impacting the broader financial and credit markets, and reducing the availability of debt and equity capital. Our acquisition of additional utility properties in 2008, combined with the divestiture of seven IPP plants, has lowered our overall corporate risk profile. Even so, our access to capital markets could be impacted by the conditions described above. Our access to adequate and cost-effective financing also depends upon our ability to maintain our investment grade issuer credit rating.

Notwithstanding these adverse market conditions, in late 2008 we extended the maturity date on the Acquisition Facility that was used to fund our purchase of utility properties from Aquila. The Acquisition Facility now expires on December 29, 2009. We anticipate that we will replace the Acquisition Facility with long-term financing in 2009.

Prospective Information

We expect long-term growth through the expansion of integrated, balanced and diverse energy operations. We recognize that sustained growth requires near continual capital deployment. The current condition of the capital markets will make it challenging to execute our strategy in the short-term, but we are confident in our ability to obtain the necessary financing to continue our growth plans. We are proactively taking prudent actions to modify our short-term plans to address the current capital market uncertainties. We will remain focused on managing our operations cautiously and maintaining our overall liquidity to meet our operating, capital and financing needs, as well as executing our long-term strategic plan.

UTILITIES GROUP

The Aquila Transaction significantly broadened our regional utility presence, more than doubled our employee count and resulted in a five-fold increase in our utility customer base. Post-close integration activities are being executed so that over the next 18 to 24 months, our workforces and systems will be combined to establish a platform upon which to continue growing our business and delivering value to our shareholders.

Electric Utilities

Business at Black Hills Power remained strong in 2008. We began construction of the Wygen III power plant, which is planned for commercial operation by mid-2010. Black Hills Power is expected to own 75% of the facility's capacity as MDU has elected to purchase a 25% ownership interest in the facility. Beginning January 1, 2009 we will benefit from newly increased transmission rates resulting from a recent FERC transmission rate case. The new rate structure also includes a formula approach to rates that will allow us to recover our capital investment as the capital is spent on the related transmission infrastructure. To accommodate both the load growth within the region and the addition of Wygen III, additional transmission infrastructure is planned over the next several years.

We are focused on Colorado Electric's pending Energy Resource Plan that has been proposed to the CPUC. Among other matters, the resource plan addresses the replacement of a purchased power agreement with PSCo that currently supplies approximately 75% of Colorado Electric's annual energy and capacity needs and expires at the end of 2011. The resource plan proposes the construction of up to five gas-fired power plants to be placed in service at the beginning of 2012. The addition of any of these plants to our utility rate base would have a significant positive impact on our financial results.

Gas Utilities

Our Gas Utilities are focused on the continued investment and strengthening of our gas distribution system, which grows our utility rate base. As further described in our Utilities Group "Regulation and Rates" discussion within Item 1 and 2 – Business and Properties of our Annual Report on Form 10-K, we have pending rate cases for Iowa Gas and Colorado Gas. Interim rates have been put in place in Iowa and conclusion is expected for both cases during 2009.

NON-REGULATED ENERGY GROUP

Power Generation

During January 2009, we completed the sale of a 23.5% interest in Wygen I to MEAN for $51.0 million. We recognized a gain on the sale of approximately $16.7 million after-tax. Concurrently with this sale, we also terminated a 10-year power purchase contract under which MEAN was obligated to buy 20 MW of power and capacity from Wygen I. The decreased revenues associated with the terminated agreement will be partially replaced by agreements under which MEAN will pay for costs associated with administrative services, plant operations and coal supplied by our Coal Mining operation.

We plan to continue evaluating opportunities to bid generation resources, both new and existing, into the requests for proposals of other regional electric utilities for their energy and capacity needs.

Coal Mining

Production from the Coal Mining segment is expected to primarily serve mine-mouth generation plants and select regional customers with long-term fuel needs. Increased demand will come from additional mine-mouth generation either currently being constructed or in various stages of development. Total annual production is estimated to be approximately 6.0 million tons in 2009, and increase by approximately 0.6 million tons per year to serve the needs of the Wygen III plant in 2010.

We experienced higher operating expenses in 2008 in part due to high diesel fuel costs. While we expect to see lower prices for diesel fuel in 2009 this benefit will likely be offset by an increase in overburden production associated with the high overburden ratios in the current phase of our mine plan.

Oil and Gas

We are focused on growing our oil and gas production through development of existing acreage and limited acquisitions based on economic and industry conditions. During 2009, we expect to limit our development capital to no more than the cash flows produced by our oil and gas properties. The current economic conditions will be particularly challenging since low commodity prices make many of our development drilling sites uneconomical, which could further reduce our development capital expenditures. The lower development capital expenditures will lead to lower production levels due to the natural production decline of existing wells.

At December 31, 2008 we recorded a $59.0 million after-tax ceiling test impairment charge to our oil and gas properties. If the early 2009 low commodity price environment continues, we will likely incur an additional significant non-cash "ceiling test" impairment charge as early as the first quarter of 2009.

Energy Marketing

We have a strong marketing portfolio with a significant amount of economic value that will be realized as the transactions settle over the next several years. The addition of more long-term transportation and storage contracts during 2008 has extended the duration of our marketing book. While we expect to derive earnings from these contracts over many years, the required methods of accounting for these transactions could result in additional earnings volatility during the term of these contracts. Our 2008 earnings were positively impacted by unrealized mark-to-market gains that accelerated margins into 2008 from proprietary positions that will not settle until 2009 and 2010.

We are currently pursuing a renewal of our uncommitted Enserco Facility prior to its May 8, 2009 expiration. We intend to seek a committed facility to replace the current uncommitted facility. Given the current condition of the credit markets, until we renew the Enserco Facility and refinance certain of our other short-term debt, we will conduct our Enserco business operation in a manner to preserve liquidity, which includes minimizing utilization of the Enserco facility. This constraint on capital could restrict Enserco's ability to take advantage of favorable transactions that may be available in the marketplace.

Corporate

We currently have interest rate swaps with a notional amount of $250.0 million, which no longer qualify for "hedge accounting" treatment provided by SFAS 133. Accordingly, all mark-to-market adjustments on these swaps are recorded through the income statement. As of December 31, 2008, these swaps had a fair value of $(94.4) million which was recorded as an unrealized mark-to-market loss in our 2008 earnings. Fluctuations in interest rates create volatility in the fair value of these swaps which will likely have a significant impact on our 2009 earnings as we record the associated unrealized mark-to-market gains or losses within our income statement.

Results of Operations

EXECUTIVE SUMMARY

Loss from continuing operations for the year 2008 was impacted by a $59.0 million after-tax non-cash charge for a ceiling test impairment of oil and gas assets due to low crude oil and natural gas prices at the end of 2008, lower margins from the Energy Marketing segment and a $61.4 million after-tax mark-to-market loss related to Corporate interest rate swaps no longer designated as hedges for accounting purposes. Solid utility performance and increased earnings from the Power Generation segment partially offset the earnings decline. Results also reflect the impacts of the IPP Transaction and the Aquila Transaction.

Earnings for the Utilities increased 39% over the prior year. Earnings were impacted by the July 14, 2008 purchase date of the five utilities acquired in the Aquila Transaction, a rate increase effective at Cheyenne Light January 1, 2008 and increased MWh sales. Partially offsetting the increases were higher maintenance and depreciation costs associated with the 95 MW coal-fired Wygen II plant, placed in commercial service January 1, 2008, and lower AFUDC.

Lower earnings from Energy Marketing were primarily attributable to a $69.3 million pre-tax decrease in realized marketing margins. Earnings were impacted by market conditions affecting both transportation and storage strategies as well as the effect of lower commodity prices on oil marketing margins. Partially offsetting these decreases was a $34.8 million increase in unrealized marketing margins.

Power Generation's improved earnings for 2008 are a result of increased earnings from equity investments as compared to 2007 and increased earnings from the Gillette CT primarily due to lower gas and purchased power costs and maintenance expense. The increase to earnings also reflects the impacts of a $1.8 million after-tax impairment charge for the Ontario plant and a $0.4 million after-tax charge for a goodwill impairment in 2007, higher allocated indirect corporate costs related to the IPP Transaction and not reclassified to discontinued operations and lower investment partnership earnings, primarily as a result of a partnership impairment charge of the Glenns Ferry and Rupert power plants in 2007.

Oil and Gas segment earnings decreased primarily as a result of the $59.0 million after-tax ceiling test impairment charge, a 7% decrease in production, and increased LOE and depletion costs. Revenues increased due to a 32% increase in the average hedged price of oil received and a 1% increase in the average hedged price of gas received, partially offset by production decreases.

Coal Mining earnings decreased due to increased overburden expense, diesel fuel costs, depreciation expense and higher mineral taxes and royalties due to increased revenues and tons sold. Revenues increased due to a 19% increase in tons of coal sold at a higher average price.

OVERVIEW

Revenue and Income (loss) from continuing operations provided by each business group were as follows (in thousands):

	2008	2007	2006
Revenue:			
Utilities	$ 749,250	$ 301,514	$ 323,003
Non-regulated Energy	256,540	273,324	219,536
Corporate	—	—	46
	$ 1,005,790	$ 574,838	$ 542,585

	2008	2007	2006
Income (loss) from continuing operations:			
Utilities	$ 43,904	$ 31,633	$ 24,188
Non-regulated Energy	(23,475)	49,520	36,588
Corporate	(72,596)	(5,872)	(5,514)
	$ (52,167)	$ 75,281	$ 55,262

The Corporate results represent unallocated costs for administrative activities that support the business segments. Corporate also includes business development activities that do not fall under the two business groups.

In February 2007, we entered into a definitive agreement with Aquila to acquire its regulated electric utility assets in Colorado and its regulated gas utilities in Colorado, Nebraska, Iowa and Kansas for $940 million, subject to customary closing adjustments. On July 14, 2008, we completed the acquisition. The purchase price was financed through a $383 million borrowing on our $1 billion acquisition credit facility and from cash proceeds generated from our IPP Transaction, which was completed on July 11, 2008. The results of operations for the acquired utilities have been included in the accompanying Consolidated Financial Statements from the date of acquisition.

Discontinued operations in 2008, 2007 and 2006 represent the results of operations and gain on sale from the IPP Transaction and the March 2006 sale of our crude oil marketing and transportation business.

2008 Compared to 2007

Consolidated loss from continuing operations for 2008 was $52.2 million, or $(1.37) per share, compared to earnings of $75.3 million, or $2.01 per share, in 2007. Income from discontinued operations was $157.2 million, or $4.12 per share, compared to income of $23.5 million, or $0.63 per share in 2007 and includes a $139.7 million gain on the sale of the operating assets from the IPP Transaction. Return on average common stock equity in 2008 and 2007 was 10.4% and 11.2%, respectively.

The Utilities Group income from continuing operations increased $12.3 million in 2008 compared to 2007. Results from the Utilities Group include the operations of the five utilities acquired in the Aquila Transaction since the July acquisition date. Earnings from continuing operations from the Electric Utilities increased $8.0 million primarily due to an increase in retail rates and increased electricity sold to retail customers. Earnings from continuing operations from the Gas Utilities were $4.2 million for the period July 14, 2008 through December 31, 2008.

The Non-regulated Energy Group's loss from continuing operations was $23.5 million in 2008, compared to earnings of $49.5 million in 2007, primarily due to a $59.0 million after-tax ceiling test impairment at the Oil and Gas segment and lower earnings from Energy Marketing of $14.5 million. Partially offsetting these decreases was an increase in Power Generation earnings of $6.6 million, which includes the impact of increased earnings from investment partnerships and lower indirect corporate costs related to the IPP Transaction.

Consolidated revenues for 2008 were $431.0 million higher than 2007 primarily due to the addition of the utilities acquired in the Aquila Transaction and increased Oil and Gas and Coal Mining revenues, partially offset by decreased revenues from Energy Marketing.

Consolidated operating expenses for 2008 increased $500.8 million compared to 2007. Operating expenses were impacted by the $91.8 million pre-tax ceiling test impairment at the Oil and Gas segment, increased overburden removal costs at the coal mine, additional operating costs from the Wygen II plant placed into service in January, 2008 and the addition of operating costs of the acquired utilities since their acquisition date.

Income from continuing operations was also impacted by a $94.4 million pre-tax mark-to-market loss related to interest rate swaps no longer designated as hedges for accounting purposes.

2007 Compared to 2006

Consolidated income from continuing operations for 2007 was $75.3 million, compared to $55.3 million in 2006, or $2.01 per share in 2007, compared to $1.65 per share in 2006. Income from discontinued operations was $23.5 million, or $0.63 per share, compared to income of $25.8 million, or $0.77 per share in 2006. Results for 2006 include the $8.9 million gain on the sale of the operating assets of the crude oil marketing and transportation business. Return on average common stock equity in 2007 and 2006 was 11.2% and 10.6%, respectively.

The Utilities Group income from continuing operations increased $7.4 million in 2007 compared to 2006. Earnings increased primarily due to an increase in retail rates and an increase in AFUDC and the associated tax benefits related to the construction of Wygen II.

The Non-regulated Energy Group's income from continuing operations increased $12.9 million in 2007, compared to 2006, primarily due to increased earnings from Energy Marketing of $16.9 million. This increase was partially offset by lower Power Generation earnings of $4.6 million primarily due to impairment charges and lower earnings from equity investments in 2007.

Unallocated corporate costs for 2007 increased $0.4 million after-tax, compared to 2006. The increase is primarily due to increased acquisition and integration costs for the Aquila acquisition offset by lower interest expense which was allocated down to the subsidiary level in 2007.

Consolidated revenues for 2007 were $32.3 million higher than 2006 due to increased revenues from the Oil and Gas, Coal Mining and Energy Marketing segments, partially offset by the Electric Utilities which had lower revenues primarily due to lower PCA and GCA pass-through cost recovery rate adjustments.

Consolidated operating expenses for 2007 increased $8.7 million compared to 2006. Increased operating expenses reflect increased compensation costs at the Energy Marketing segment, a $4.3 million increase in depreciation, depletion and amortization expense, primarily due to increased depletion at the Oil and Gas segment, and a $6.0 million increase in operations and maintenance expense. The increased expenses were partially offset by a $30.6 million decrease in fuel and purchased power primarily due to cost recovery adjustments.

Income from continuing operations was also impacted by a $4.8 million decrease in interest expense primarily due to the reduction of debt, using in part, proceeds from the issuance and sale of common stock, and the effect of interest capitalization during ongoing construction and development.

A discussion of operating results from our business segments follows.

The following business group and segment information does not include discontinued operations or intercompany eliminations. Accordingly, 2008, 2007 and 2006 information has been revised to remove information related to operations that were discontinued.

UTILITIES

Electric Utilities

Operating results for the Electric Utilities are as follows:

(in thousands)	2008	2007	2006
Revenue – electric	$ 425,123	$ 270,943	$ 275,329
Revenue – gas	48,296	32,468	50,026
Total revenue	473,419	303,411	325,355
Fuel and purchased power – electric	222,826	133,289	146,180
Purchased gas	33,735	22,649	39,957
Total fuel and purchased power	256,561	155,938	186,137
Gross margin – electric	202,297	137,654	129,149
Gross margin – gas	14,561	9,819	10,069
Total gross margin	216,858	147,473	139,218
Operating expenses	138,992	94,161	93,262
Operating income	$ 77,866	$ 53,312	$ 45,956
Income from continuing operations and net income	$ 39,674	$ 31,633	$ 24,188

	2008	2007	2006
Regulated power plant fleet availability:			
Coal-fired plants	93.7%	95.4%	93.5%
Other plants	91.4%	99.4%	98.6%
Total availability	92.8%	97.2%	95.7%

2008 Compared to 2007

2008 results include the operations of Colorado Electric, which was acquired on July 14, 2008.

Income from continuing operations increased 25% primarily due to:

- An increase in earnings of approximately $8.0 million primarily due to the impact of a rate increase at Cheyenne Light effective January 1, 2008; and
- A 34% increase in electric MWh sales to retail customers, primarily due to the acquisition of Colorado Electric.

Partially offsetting the increase to earnings was the following:

- Increased plant maintenance costs and depreciation expense of approximately $11.1 million associated with the Wygen II plant placed into service January 1, 2008; and
- Lower AFUDC compared to 2007.

2007 Compared to 2006

Income from continuing operations increased 31% primarily due to the following:

- Purchased power costs decreased 13% due to an 8% decrease in electricity purchased at a lower average price;
- Margins from wholesale off-system sales increased 7%;
- A $1.0 million decrease in write-off of uncollectible accounts; and
- Lower property tax due to lower assessed property valuations.

Partially offsetting the increases to earnings were the following:

- Revenues decreased 7% primarily due to a 17% decrease in wholesale off-system sales and the effects of fluctuations in cost of electricity and gas that flow through to revenues through cost recovery rate adjustments, partially offset by increased rates that went into effect January 1, 2007; and
- A $4.8 million increase in interest expense due to increased borrowings and net of the capitalized interest component of AFUDC.

Gas Utilities

Operating results for the Gas Utilities are as follows:

	For the Period July 14, 2008 to December 31, 2008 (in thousands)
Revenue:	
Natural gas – regulated	$ 261,887
Other – non-regulated	15,189
Total sales	277,076
Cost of sales:	
Natural gas – regulated	180,556
Other – non-regulated	11,294
Total cost of sales	191,850
Gross margin	85,226
Operating expenses	70,338
Operating income	$ 14,888
Income from continuing operations and net income	$ 4,230

As part of the Aquila Transaction, we acquired Gas Utilities in Colorado, Nebraska, Iowa and Kansas. Natural gas demand is typically higher in the first and fourth quarters as it is typically used for residential and commercial heating.

The Gas Utilities have GCAs that allow them to pass through the cost of gas to customers. For this reason, we believe gross margins are a more useful performance measure than revenues as fluctuations in the cost of gas are passed through to revenues.

In June 2008, Iowa Gas filed for a $13.6 million rate increase. Interim rates were implemented on June 13, 2008. The IUB issued an order extending the time limit for consideration of the general rate increase and has until July 2, 2009 to issue a decision on our rate request. If interim rates exceed final approved rate, the difference plus interest will be refunded or credited to customers.

In June 2008, Colorado Gas filed for a $2.8 million rate increase. On February 4, 2009, a settlement of the rate case for $1.4 million was presented to an administrative law judge. The administrative law judge will make a recommendation regarding the settlement to the CPUC. The CPUC has until June 16, 2009 to issue a decision on our rate request. Other non-regulated is related to services provided to our customers.

NON-REGULATED ENERGY GROUP

Oil and Gas

Oil and Gas operating results were as follows:

(in thousands)	2008	2007	2006
Revenue	$ 106,347	$ 101,522	$ 95,078
Operating expenses*	177,535	76,085	68,990
Operating (loss) income	$ (71,188)	$ 25,437	$ 26,088
Income (loss) from continuing operations	$ (49,668)	$ 12,706	$ 12,736

* 2008 operating expenses included a $91.8 million pre-tax ceiling test impairment charge.

The following tables provide certain operating statistics for the Oil and Gas segment;

Crude Oil and Natural Gas Production	2008	2007	2006
Bbls of oil sold	387,400	409,040	401,440
Mcf of natural gas sold	11,209,600	12,172,400	12,005,600
Mcf equivalent sales	13,534,000	14,626,640	14,414,240

Average Price Received*	2008	2007	2006
Gas/Mcf**	$ 6.24	$ 6.19	$ 6.11
Oil/Bbl	$ 79.35	$ 60.29	$ 50.75

* Net of hedge settlement gains/losses

** Exclusive of gas liquids

	2008	2007	2006
Average production cost (per Mcfe):			
LOE	$ 1.33	$ 0.98	$ 1.01
Production and other taxes	0.91	0.70	0.67
Total	$ 2.24	$ 1.68	$ 1.68

Depletion	2008	2007	2006
Depletion expense/Mcfe*	$ 2.68	$ 2.21	$ 1.94

* The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented. The 2008 rate was particularly impacted by product price volatility and significantly lower year-end market prices, which resulted in lower oil and gas reserve quantities.

The following is a summary of annual average operating expenses per Mcfe at December 31:

	2008			2007			2006		
	LOE	Gathering Compression and Processing	Total	LOE	Gathering Compression and Processing	Total	LOE	Gathering Compression and Processing	Total
New Mexico	$ 1.48	$ 0.29	$ 1.77	$ 1.04	$ 0.31	$ 1.35	$ 1.11	$ 0.27	$ 1.38
Colorado	1.29	0.77	2.06	0.95	0.79	1.74	1.25	0.49	1.74
Wyoming	1.55	–	1.55	1.19	–	1.19	1.15	–	1.15
All other properties	0.89	0.12	1.01	0.71	0.17	0.88	0.73	0.15	0.88
Total	$ 1.33	$ 0.22	$ 1.55	$ 0.98	$ 0.23	$ 1.21	$ 1.01	$ 0.18	$ 1.19

At the East Blanco Field in New Mexico and our Piceance Basin assets in Colorado, we own and operate gas gathering systems, including associated compression and treating facilities.

The following is a summary of our proved oil and gas reserves at December 31:

	2008	2007	2006
Bbls of oil (in thousands)	5,185	5,807	5,723
MMcf of natural gas	154,432	172,964	164,754
Total MMcfe	185,542	207,806	199,092

Reserves are based on reports prepared by an independent consulting and engineering firm. The reports were prepared by Cawley, Gillespie & Associates, Inc. in 2008 and 2007, and Ralph E. Davis Associates, Inc. in 2006. Reserves were determined using constant product prices at the end of the respective years. Estimates of economically recoverable reserves and future net revenues are based on a number of variables, which may differ from actual results. The current estimate takes into account 2008 production of approximately 13.0 Bcfe, additions from extensions, discoveries and acquisitions of 10.0 Bcfe and negative revisions to previous estimates of 19.0 Bcfe, including approximately 15.0 Bcfe due to lower product prices and higher costs.

Reserves reflect year end pricing held constant for the life of the reserves, as follows:

	2008		2007		2006	
	Oil	Gas	Oil	Gas	Oil	Gas
Year-end prices (NYMEX)	$ 44.60	$ 5.71	$ 95.98	$ 6.80	$ 61.05	$ 5.52
Year-end prices (average well-head)	$ 32.74	$ 4.44	$ 83.23	$ 5.88	$ 52.06	$ 5.34

2008 Compared to 2007

Loss from continuing operations was $49.7 million compared to income of $12.7 million in the prior year, primarily due to the following:

- A $59.0 million after-tax non-cash ceiling test impairment charge was taken during the fourth quarter 2008. The write-down in value of our natural gas and crude oil properties resulted from low year-end prices for the commodities. The write-down of gas and oil properties was based on year end NYMEX prices of $5.71 per Mcf, adjusted to $4.44 per Mcf at the wellhead, for natural gas and $44.60 per barrel, adjusted to $32.74 per barrel at the wellhead, for crude oil;
- LOE increased $3.6 million due to costs related to severe weather conditions in New Mexico, increased fuel costs and higher industry-related costs; and
- Increased depletion expense of $3.7 million primarily due to negative reserve revisions driven by the impact of lower year-end commodity prices.

Partially offsetting these decreases were the following:

- Increased revenues of $4.8 million primarily due to a 32% increase in the annual average hedged price of oil received and a 1% increase in the annual average hedged price of gas received, partially offset by a 7% decrease in production and the impact of a royalty settlement with the Jicarilla Apache Nation. The decrease in production resulted from severe weather at the beginning of 2008, federal drilling permit delays, voluntary shut-in of volumes in response to low price levels at the CIG pricing location and delays in drilling activity on our non-operated property as well as a reduction in capital spending due to the low commodity prices.

In 2008, we acquired additional non-operated interest in a Wyoming field in which we already held non-operated interests. The additional interest added approximately 4 Bcfe of proved reserves and is viewed as a long-term production field with increased density and up-hole re-completion potential.

2007 Compared to 2006

Income from continuing operations was comparable to the prior year.

- Revenues from oil and gas sales increased 7% due to a 2% increase in oil volumes at average prices received that were 19% higher than prior year and increased gas sales of 1%, at a 1% higher average gas price received;
- Operations and maintenance costs increased 8% due to increases in the number of wells and higher industry costs for services and equipment;
- General and administrative costs increased 15% primarily due to higher corporate allocations and increased labor costs resulting from staffing increases to support development of 2006 acquisitions;
- Depletion per Mcfe increased 14% primarily due to increases in current year finding costs and forecasted future development costs and higher industry-wide cost increases; and
- Interest expense increased 26% due to carrying a full year of Piceance Basin acquisition debt and increased borrowings to fund drilling and exploration activity.

Additional information on our Oil and Gas operations can be found in Note 22 to the Notes to Consolidated Financial Statements in this Annual Report.

Power Generation

Our Power Generation segment produced the following results:

(in thousands)	2008	2007	2006
Revenue	$ 38,181	$ 38,658	$ 40,688
Operating expenses	23,966	36,062	32,407
Operating income	$ 14,215	$ 2,596	$ 8,281
Income (loss) from continuing operations	$ 3,121	$ (3,471)	$ 1,117

The following table provides certain operating statistics for the Power Generation segment:

	2008	2007	2006
Independent power capacity:			
MW of independent power capacity in service	141	158	164
Contracted fleet plant availability:			
Gas-fired plants	96.2%	96.2%	94.7%
Coal-fired plants	95.3%	70.3%	95.7%
Total	95.9%	86.0%	95.3%

2008 Compared to 2007

Earnings from continuing operations increased $6.6 million primarily due to:

- Increased earnings from our investment partnerships due to 2007 partnership impairment charges of $2.1 million after-tax for the Glenns Ferry and Rupert power plants, in which we hold a 50% ownership interest;
- Increased operating income from our Gillette CT of $1.0 million after-tax. Operating income was impacted by lower gas and purchased power costs and maintenance expense;
- Allocated indirect corporate costs, related to the IPP assets sold and not reclassified to discontinued operations, decreased $1.9 million after-tax. 2008 costs represent a partial year through the sale date of the IPP Transaction, compared to a full 12 months of costs in 2007; and
- The recording of an impairment loss, and related costs, in 2007 of $1.8 million after-tax relating to the Ontario plant.

Partially offsetting the increased earnings was a decrease in non-operating income of $6.4 million after-tax, resulting from a change in business segment debt to equity capital structure.

2007 Compared to 2006

Income from continuing operations decreased $4.6 million primarily due to the following:

- Decreased earnings of approximately $1.8 million after-tax due to the impairment of the Ontario plant; and
- Decreased equity earnings of unconsolidated subsidiaries of approximately $2.1 million after-tax due to the partnership impairment charges for the Glenns Ferry and Rupert power plants, in which we hold a 50% interest.

Coal Mining

Coal Mining results were as follows:

(in thousands)	2008	2007	2006
Revenue	$ 56,901	$ 42,488	$ 36,282
Operating expenses	52,608	36,311	29,366
Operating income	$ 4,293	$ 6,177	$ 6,916
Income from continuing operations	$ 4,033	$ 6,107	$ 5,877

The following table provides certain operating statistics for the Coal Mining segment:

(in thousands)	2008	2007	2006
Tons of coal sold	6,017	5,049	4,717
Cubic yards of overburden moved	12,203	7,467	6,295
Coal reserves	274,000	280,000	285,000

2008 Compared to 2007

Income from continuing operations decreased $2.1 million, or 34%, due to the following:

- Increased overburden removal costs of $5.3 million due to a 63% increase in overburden yards moved, compounded by a higher strip ratio, longer haul distances and higher diesel fuel costs; and
- Increased depreciation expense of $4.4 million due to an increase in the asset base and usage related to increased production.

Offsetting the decreases was a $14.4 million increase in revenues due to a 19% increase in coal sold at a higher average price. The increase in coal volumes was due to additional Wygen II and train load-out sales.

2007 Compared to 2006

Income from continuing operations increased 4% due to a 17% increase in revenues, primarily due to increases in coal pricing, sales in December 2007 to the Wygen II plant for test power, which was placed into commercial service January 1, 2008, and lower revenues in 2006 due to scheduled and unscheduled outages at the Wyodak plant.

Partially offsetting the increased revenues and earnings were the following:

- Increased overburden removal costs due to a 19% increase in cubic yards moved;
- Increased royalty expense primarily due to the increase in revenues; and
- Increased mining taxes primarily related to the increase in revenues and tons.

Energy Marketing

Our Energy Marketing segment produced the following results:

(in thousands)	2008	2007	2006
Revenue -			
Realized gas marketing gross margin	$ 18,593	$ 84,823	$ 54,088
Unrealized gas marketing gross margin	33,247	468	(6,546)
Realized oil marketing gross margin	1,038	4,146	2,847
Unrealized oil marketing gross margin	6,432	4,399	842
	59,310	93,836	51,231
Operating expenses	29,175	42,067	27,223
Operating income	$ 30,135	$ 51,769	$ 24,008
Income from continuing operations	$ 19,689	$ 34,178	$ 17,322

The following table provides certain operating statistics for the Energy Marketing segment:

	2008	2007	2006
Natural gas average daily physical sales – MMBtu	1,873,400	1,743,500	1,598,200
Crude oil average daily physical sales – Bbls	7,880	8,600	8,800

2008 Compared to 2007

Income from continuing operations decreased $14.5 million due to the following:

- A $69.3 million pre-tax decrease in realized marketing margins, primarily due to prevailing conditions in natural gas markets affecting both transportation and storage strategies; and
- Lower crude oil marketing margins are due to the impact of decreasing commodity prices on inventory held to meet pipeline requirements.

Partially offsetting the decrease was the following:

- A $34.8 million pre-tax increase in unrealized marketing margins. Unrealized mark-to-market gains in 2008 were driven by accelerated margins within our proprietary trading portfolio and narrowing basis differentials at year end, resulting in mark-to-market gains on our hedged transportation positions. These positions are scheduled to settle and the margins realized primarily in 2009 and to a lesser extent 2010; and
- Lower operating expenses as incentive compensation decreased compared to incentive compensation for strong marketing performance in 2007.

2007 Compared to 2006

Income from continuing operations increased $16.9 million due to the following:

- Realized gross margins from gas marketing increased $30.7 million over the prior year and physical gas volumes marketed increased 9%;
- A full year of margins from oil marketing operations, which began in May 2006;
- Gas marketing unrealized mark-to-market gains were $7.0 million higher; and
- Lower professional fees as compared to cost incurred in 2006 related to litigation costs.

Partially offsetting the earnings increase was the following:

- Increased tax expense for higher estimated occupation taxes; and
- Increased compensation costs related to higher realized marketing margins.

Critical Accounting Policies

We prepare our consolidated financial statements in conformity with GAAP. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We believe the following accounting policies are the most critical in understanding and evaluating our reported financial results. We have reviewed these critical accounting policies and related disclosures with our Audit Committee. Actual results may differ from our estimates.

The following discussion of our critical accounting policies should be read in conjunction with Note 1, "Business Description and Summary of Significant Accounting Policies" of our Notes to Consolidated Financial Statements.

IMPAIRMENT OF LONG-LIVED ASSETS

We evaluate for impairment, the carrying values of our long-lived assets, including goodwill and other intangibles, whenever indicators of impairment exist and at least annually for goodwill as required by SFAS 142.

For long-lived assets with finite lives, this evaluation is based upon our projections of anticipated future cash flows (undiscounted and without interest charges) from the assets being evaluated. If the sum of the anticipated future cash flows over the expected useful life of the assets is less than the assets' carrying value, then a permanent non-cash write-down equal to the difference between the assets' carrying value and the assets' fair value is required to be charged to earnings. In estimating future cash flows, we generally use a probability weighted average expected cash flow method with assumptions based on those used for internal budgets. The determination of future cash flows, and, if required, fair value of a long-lived asset is by it nature a highly subjective judgment. Significant judgment assumptions are required in the forecast of future operating results used in the preparation of the long-term estimated cash flows. Changes in these estimates could have a material effect on the evaluation of our long-lived assets.

According to SFAS 142, goodwill and other intangibles are required to be evaluated whenever indicators of impairment exist and at least annually. We conduct our annual evaluations during the fourth quarter. The standard requires a two-step process be performed to analyze whether or not goodwill has been impaired. The first step of this test, used to identify potential impairment, compares the estimated fair value of a reporting unit with its carrying amount. The second step, if necessary, measures the amount of the impairment. The underlying assumptions used for determining fair value are susceptible to change from period to period and could potentially cause a material impact to the income statement. Management's assumptions about future revenues and operating costs, the amount and timing of anticipated capital expenditures for power generating facilities at our utility operations, discount rates, inflation rates, and economic conditions, require significant judgment. The 2008 Aquila Transaction resulted in a significant increase in our goodwill balance. As of December 31, 2008, our total goodwill relating to the Aquila Transaction was $344.5 million.

REGULATORY ACCOUNTING

We account for certain regulated operations under the provisions of SFAS 71. As a result, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probably of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that either are not likely to or have yet to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders to other regulatory entities, and the status of any pending or potential deregulation issues. These assessments reflect the current political and regulatory climate at the state and federal levels, and are subject to change in the future.

UNBILLED UTILITY REVENUES

Sales related to the delivery of energy are generally recorded when services or energy is delivered to customers. However, the determination of sales is based on reading customers' meters, which occurs systematically throughout the month. At the end of each month, an estimate is made of the amount of energy delivered to customers after the date of the last meter reading. The unbilled revenue is calculated each month based on estimated customer usage, weather factors, line losses, and applicable customer rates. Total unbilled revenues at December 31, 2008 were $73.0 million.

FULL COST METHOD OF ACCOUNTING FOR OIL AND GAS ACTIVITIES

Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are available – successful efforts and full cost. We account for our oil and gas activities under the full cost method whereby all productive and nonproductive costs related to acquisition, exploration and development drilling activities are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Net capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net revenues of proved reserves and the lower of cost or fair value of unproved properties. This method values the reserves based upon actual oil and gas spot prices at the end of each reporting period adjusted for contracted price changes. The prices, as well as costs and development capital, are assumed to remain constant for the remaining life of the properties. If the net capitalized costs exceed the full-cost ceiling, then a permanent non-cash write-down is required to be charged to earnings in that reporting period. Our net capitalized costs were more than the full cost ceiling at December 31, 2008 requiring an after-tax write-down of $59.0 million. Given the fluctuations in natural gas and oil prices, we can provide no assurance that future write-downs will not occur depending on oil and gas prices at that point in time. On December 31, 2008, the SEC issued final rules amending its oil and gas reporting requirements effective January 1, 2010. The final rule changes the use of prices at the end of each reporting period to an average of the first day of the month price for the preceding twelve months. The SEC has proposed to apply these rules to the Annual Reports on Form 10-K for the period ending December 31, 2009, however there is the possibility of delaying the compliance date until the FASB has issued final accounting standards in line with the SEC rules.

OIL AND NATURAL GAS RESERVE ESTIMATES

Estimates of our proved oil and natural gas reserves are based on the quantities of oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. An independent petroleum engineering company prepares reports that estimate our proved oil and natural gas reserves annually. The accuracy of any oil and natural gas reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. In addition, as oil and gas prices and cost levels change from year to year, the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

Despite the inherent imprecision in estimating our oil and natural gas reserves, the estimates are used throughout our financial statements. For example, since we use the unit-of-production method of calculating depletion expense, the amortization rate of our capitalized oil and gas properties incorporates the estimated unit-of-production attributable to the estimates of proved reserves. The net book value of our oil and gas properties is also subject to a "ceiling" limitation based in large part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

RISK MANAGEMENT ACTIVITIES

In addition to the information provided below, see Note 2 "Risk Management Activities," of our Notes to Consolidated Financial Statements in this Annual Report.

Derivatives

We account for derivative financial instruments in accordance with SFAS 133. Accounting for derivatives under SFAS 133 requires the recognition of all derivative instruments as either assets or liabilities on the balance sheet and their measurement at fair value. Our policy for recognizing the changes in fair value of derivatives varies based on the designation of the derivative. The changes in fair value of derivatives that are not designated as hedges under SFAS 133 are recognized currently in earnings. Derivatives may be designated as hedges of expected future cash flows or fair values. The effective portion of changes in fair values of derivatives designated as cash flow hedges is recorded as a component of other comprehensive income (loss) until it is reclassified into earnings in the same period that the hedged item is recognized in earnings. The ineffective portion of changes in fair value of derivatives designated as cash flow hedges is recorded in current earnings. Changes in fair value of derivatives designated as fair value hedges are recognized in current earnings along with fair value changes of the underlying hedged item.

We currently use derivative instruments, including options, swaps, futures, forwards and other contractual commitments for both non-trading (hedging) and trading purposes. Our typical non-trading (hedging) transactions relate to contracts we enter into to fix the price received for anticipated future production at our Oil and Gas segment, or to fulfill the annual winter hedging plan for our gas utilities (see below), and for interest rate swaps we enter into to convert a portion of our variable rate debt, or associated variable rate interest payments, to a fixed rate. Our Energy Marketing operations utilize various physical and financial contracts to effectively manage our marketing and trading portfolios.

Fair values of derivative instruments and energy trading contracts are based on actively quoted market prices or other external source pricing information, where possible. If external market prices are not available, fair value is determined based on other relevant factors and pricing models that consider current market and contractual prices for the underlying financial instruments or commodities, as well as time value and yield curve or volatility factors underlying the positions.

Pricing models and their underlying assumptions impact the amount and timing of unrealized gains and losses recorded, and the use of different pricing models or assumptions could produce different financial results. Changes in the commodity markets will impact our estimates of fair value in the future. To the extent financial contracts have extended maturity dates, our estimates of fair value may involve greater subjectivity due to the lack of transparent market data available upon which to base modeling assumptions.

As allowed by state regulatory commissions, we have entered into certain financial instruments to reduce our customers' underlying exposure to fluctuations in gas prices. These financial instruments are considered derivatives under SFAS 133 and are marked-to-market. We apply the provisions of SFAS 71 to periodic changes in fair value of the derivatives associated with these instruments and record an offset in regulatory asset or regulatory liability accounts. Most of our contracts for purchase and sale of natural gas qualify for the normal purchase and normal sale exceptions under SFAS 133, and are not required to be recorded as derivative assets and liabilities.

Counterparty Credit Risk and Allowance for Doubtful Accounts

Our largest counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. Recent adverse developments in the global financial and credit markets have made it more difficult and more expensive for companies to access the short-term capital markets, which may negatively impact the creditworthiness of our counterparties. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and collateral requirements under certain circumstances, including the use of master netting agreements in our natural gas marketing segment.

We continuously monitor collections and payments from our customers and establish an allowance for doubtful accounts based upon our historical experience and any specific customer collection issue that we have identified. The allowances provided are estimated and may be impacted by economic, market and regulatory conditions, which could have an effect on future allowance requirements and significantly impact future results of operations. While most credit losses have historically been within our expectations and established provisions, we can provide no assurance that our credit losses will be consistent with our estimates.

PENSION AND OTHER POSTRETIREMENT BENEFITS

The Company, as described in Note 17 to the Consolidated Financial Statements in this Annual Report, has three defined benefit pension plans and three defined benefit post-retirement healthcare plans. Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the discount rate for measuring the present value of future plan obligations; expected long-term rates of return on plan assets; rate of future increases in compensation levels; and healthcare cost projections. The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the assumptions used by actuaries in calculating the amounts. Through 2007, we reviewed the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a September 30 measurement date. Effective in 2008, we changed our measurement date to December 31. Although we believe our assumptions are appropriate, significant differences in our actual experience or significant changes in our assumptions may materially affect our pension and other postretirement obligations and our future expense.

The pension benefit cost for 2009 for our non-contributory funded pension plan is expected to be $11.8 million compared to $1.8 million in 2008. The estimated discount rate used to determine annual benefit cost accruals will be 6.20% in 2009; the discount rate used in 2008 was 6.35%. In selecting the discount rate, we consider cash flow durations for each Plan's liabilities and returns on high credit quality fixed income yield curves for comparable durations.

Our pension plan assets are held in trust and primarily consist of equity, fixed income and real estate securities. In 2008, our target long-term investment allocations were 75% equity and 25% fixed income. As a result of the severe decline in equity values in the fourth quarter of 2008 and in light of the improved relative value of fixed income investment opportunities, we are undergoing a review to consider a revision of the pension plan investment allocations.

The revision is expected to result in a higher fixed income allocation. Until the investment allocation review is completed and implemented, we have suspended our practice of rebalancing the portfolio on a quarterly basis. This has resulted in an investment allocation of 60% equities, 35% fixed income/cash and 5% real estate at December 31, 2008.

As of December 31, 2008, our average assumed discount rate was 6.2% and our average expected return on plan assets was 8.5%. We do not pre-fund our non-qualified pension plans or two of the three postretirement benefit plans. The table below shows the expected impacts of a 1% increase or decrease to our 6.2% discount rate assumption:

Change in Assumed Discount Rate (in thousands)	Impact on December 31, 2008 Accumulated Postretirement Benefit Obligation	Impact on 2008 Service and Interest Cost
Increase 1%	$ 3,445	$ 325
Decrease 1%	$ (2,552)	$ (251)

CONTINGENCIES

When it is probable that an environmental or other legal liability has been incurred, a loss is recognized when the amount of the loss can be reasonably estimated. Estimates of the probability and the amount of loss are made based on currently available facts. Accounting for contingencies requires significant judgment regarding the estimated probabilities and ranges of exposure to potential liability. Our assessment of our exposure to contingencies could change to the extent there are additional future developments, or as more information becomes available. If actual obligations incurred are different from our estimates, the recognition of the actual amounts could have a material impact on our financial position and results of operations.

VALUATION OF DEFERRED TAX ASSETS

We use the liability method of accounting for income taxes. Under this method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of the current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements.

Liquidity and Capital Resources

OVERVIEW

Information about our financial position as of December 31 is presented in the following table:

Financial Position Summary	2008	2007	Percentage Change
(in thousands)			
Cash and cash equivalents	$ 168,491	$ 76,889	119.1%
Short-term debt	705,878	167,326	321.9%
Long-term debt	501,252	503,301	(0.4)%
Stockholders' equity	1,050,536	969,855	8.3%
Ratios			
Long-term debt ratio	32.3%	34.2%	(5.5)%
Total debt ratio	53.5%	40.9%	30.8%

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt financings, taken as a whole, provide sufficient resources to fund our ongoing operating requirements, debt maturities, anticipated dividends, and anticipated capital expenditures during the next 12 months, however, a material change in available financing (including further changes resulting from the ongoing financial crisis) could impact our ability to fund our current liquidity and capital resource requirements.

Liquidity

Historically, our principal sources of short-term liquidity have been our revolving credit facilities and cash from operations. We have utilized availability under our revolving credit facilities to manage our cash flows, principally due to the seasonality of our utility businesses and changes in the trading volumes of our energy marketing operation. Our principal sources of long-term liquidity have been proceeds raised from public and private offerings of equity and long-term debt securities issued by the Company and its subsidiaries. We have also managed liquidity needs through hedging activities, primarily in connection with seasonal needs of our Utility operations (including seasonal peaks in fuel requirements), interest rate movements, and commodity price movements. As a result of the recent turmoil in the capital and credit markets, we expect to improve our liquidity profile by deferring or curtailing discretionary capital expenditures and operate certain of our businesses in a manner that conserves cash.

At December 31, 2008, we had approximately $168.5 million of unrestricted cash on hand, and had $508.2 million of cash borrowings and letters of credit outstanding under our credit facilities, as set forth below.

Credit Facility	Expiration	Maximum Capacity	Borrowings and Letters of Credit Issued at December 31, 2008
(in millions)			
Unsecured Revolving Credit Facility	May 4, 2010	$ 525.00	$ 381.70
Enserco Facility	May 8, 2009	$ 300.00	$ 126.50

CREDIT FACILITIES

Corporate Credit Facility

In July 2008, our unsecured revolving credit facility was increased from $400 million to $525 million. The cost of borrowing or letters of credit under our corporate revolver is determined based on our credit ratings. At our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70 basis points over LIBOR (which equates to a 1.14% one-month borrowing rate as of December 31, 2008). The revolver can be used to fund our working capital needs and for general corporate purposes. At December 31, 2008, we had borrowings of $321.0 million and $60.7 million of letters of credit issued under the facility, and we had approximately $143.3 million of capacity available for additional borrowings or letters of credit.

Our revolving credit facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintenance of the following financial covenants: (i) a consolidated net worth in an amount of not less than the sum of $625 million and 50% of our aggregate consolidated net income beginning January 1, 2005; (ii) a recourse leverage ratio not to exceed 0.70 to 1.00 for the first year after the Aquila Transaction and, thereafter, a ratio not to exceed 0.65 to 1.00; and, (iii) an interest expense coverage ratio of not less than 2.5 to 1.0. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding.

At December 31, 2008, our consolidated net worth was $1,050.5 million, which was approximately $266.4 million in excess of the net worth we were required to maintain under the credit facility. At December 31, 2008, our long-term debt ratio was 32.3%, our total debt leverage (long-term debt and short-term debt) was 53.5%, our recourse leverage ratio was approximately 56.3% and our interest expense coverage ratio for the twelve month period ended December 31, 2008 was 3.89 to 1.0. Accordingly, we were in compliance with all of our financial covenants in the revolving credit facility as of December 31, 2008.

In addition to covenant violations, an event of default under the credit facility may be triggered by other events, such as a failure to make payments when due or a failure to make payments when due in respect of, or a failure to perform obligations relating to, other debt obligations of $20 million or more. Subject to applicable cure periods (none of which apply to a failure to timely pay indebtedness), an event of default would permit the lenders to restrict our ability to further access the credit facility for loans or new letters of credit, and could require both the immediate repayment of any principal and interest outstanding and the cash collateralization of outstanding letter of credit obligations.

The credit facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after giving effect to such action.

Enserco Facility

Our Energy Marketing subsidiary, Enserco, has a $300 million uncommitted, discretionary line of credit to provide support for the purchase, sale, transportation and storage of natural gas and crude oil. The line of credit is secured by Enserco's assets, and it expires on May 8, 2009. The Enserco credit facility allows for the issuance of letters of credit and loans for our marketing operations. The cost of letters of credit issued under the facility is determined by the type of transaction the letter of credit is securing and ranges from an annualized cost of 100 basis points to 150 basis points. We have not historically used the facility for loans. Outstanding borrowings accrue interest at the higher of: 50 basis points above the Federal Funds Rate (0.75 percent at December 31, 2008) or 100 basis points above prime (4.25 percent at December 31, 2008). The maximum aggregate amount of such letters of credit and loans issued under the facility is subject to a borrowing base sublimit. The sublimit is determined based on the net working capital and tangible net worth of Enserco. Loans under the facility are subject to a maximum sublimit of $100 million. At December 31, 2008, $126.5 million of letters of credit were issued under the facility and there were no cash borrowings outstanding.

Acquisition Facility

In July 2008, in conjunction with the closing of the Aquila Transaction, we borrowed $382.8 million under our $1 billion bridge acquisition credit facility dated May 7, 2007. The Acquisition Facility was structured as a single-draw term loan facility for the sole purpose of financing the Aquila Transaction and following our July 2008 borrowing we have no additional borrowing capacity available under the facility.

Borrowings under the term loan are available under a base rate option, which is based on the then-current prime rate, or under a LIBOR option, which is based on the then-current LIBOR plus an applicable margin. The applicable margin for LIBOR borrowings was originally 55 basis points during the period from the initial funding under the term loan to six months thereafter, 67.5 basis points during the period from six months and one day after the initial funding to nine months thereafter, and 92.5 basis points during the period from nine months and one day after the initial funding until the loan maturity. The loan was originally scheduled to mature on February 5, 2009. However, on December 18, 2008, we amended the facility to provide as follows:

- The maturity date was extended from February 5, 2009 to December 29, 2009;
- The applicable margin for base-rate borrowings was increased to (i) 200 basis points for the period commencing December 18, 2008 through March 31, 2009, (ii) 250 basis points for the period commencing April 1, 2009 through June 30, 2009, (iii) 300 basis points for the period commencing July 1, 2009 through September 30, 2009, and (iv) 350 basis points thereafter. If our credit ratings, as assigned by S&P and Moody's, fall below investment grade credit ratings, the applicable margin will increase by an additional 25 basis points; and
- Increased the applicable margin for LIBOR borrowings to (i) 300 basis points for the period commencing December 18, 2008 through March 31, 2009, (ii) 350 basis points for the period commencing April 1, 2009 through June 30, 2009, (iii) 400 basis points for the period commencing July 1, 2009 through September 30, 2009, and (iv) 450 basis points thereafter. If our credit ratings, as assigned by S&P and Moody's, fall below investment grade credit ratings and the applicable margin will increase by 25 basis points.

In connection with the amendment, we also received the consents necessary to replace the administrative agent (ABN AMRO Bank) and appointed The Royal Bank of Scotland PLC as successor agent.

As of December 31, 2008, the facility has a borrowing spread of 300 basis points over LIBOR (which equates to a 3.44% one-month borrowing rate as of December 31, 2008).

The Acquisition Facility also includes certain affirmative and negative covenants and events of default that largely replicate the covenants in our corporate revolving credit facility. We were in compliance with all such covenants as of December 31, 2008.

Cross-Default Provisions

Our revolving credit facility and acquisition term loan facility contain cross-default provisions that would result in an event of default under the credit facility upon (i) a failure by us or certain of our subsidiaries (including, among others, Enserco and most of our Utility subsidiaries) to timely pay indebtedness in an aggregate principal amount of $20 million or more, or (ii) the occurrence of a default under any agreement under which we or certain of our subsidiaries (including, among others, Enserco and most of our Utility subsidiaries) may incur indebtedness in an aggregate principal amount of $20 million or more, and such default continues for a period of time sufficient to permit an acceleration of the maturity of such indebtedness or a mandatory prepayment of such indebtedness. In addition, each of our credit facilities contains default provisions under which an event of default would result if we or certain of our subsidiaries (including, among others, Enserco and most of our Utility subsidiaries) fail to timely make certain payments, such as ERISA funding obligations or payments in satisfaction of judgments, in an aggregate principal amount of $20 million or more.

Working Capital

The most significant activities impacting working capital are our capital expenditures and the purchase of natural gas for our Gas Utilities. We could experience significant working capital requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices. We anticipate using the combination of credit capacity available under our corporate revolver and cash on hand to meet our peak winter working capital requirements.

Collateral

As of December 31, 2008, we had posted with counterparties the following amounts (in thousands) of collateral (in the form of cash or letters of credit):

Trading positions (energy marketing)	$	110,205
Utility cash collateral requirements		8,744
Total Funds on Deposit	$	118,949

Collateral requirements for our trading positions will fluctuate based on the movement in commodity prices and our credit rating. Changes in collateral requirements will vary depending on the magnitude of the price movement and the current position of our energy marketing trading portfolio. As these trading positions settle in the future, the collateral will be returned.

We are required to post collateral with certain commodity and pipeline transportation vendors. This amount will fluctuate depending on gas prices and projected volumetric deliveries.

Debt Retirement Transactions

In 2006, we entered into a credit agreement under which floating-rate debt was issued to finance the Wygen I project. The project debt matured in June 2008. We retired the $128.3 million of project debt with cash borrowed under our revolving credit facility. See "Off-Balance Sheet Arrangements – Variable Interest Entities" below for additional information.

In conjunction with the completion of the IPP Transaction, $67.5 million of project debt relating to certain Colorado IPP facilities was retired in July 2008. We used proceeds from the IPP Transaction to retire this debt.

Utility Money Pool

As a utility holding company, we are required to establish a cash management program to address lending and borrowing activities between our utility subsidiaries and the Company. We have established utility money pool agreements which address these requirements. These agreements are on file with FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates. While the utility money pool may borrow funds from the Company (as ultimate parent company), the money pool arrangement does not allow loans from our utility subsidiaries to the Company (as ultimate parent company) or to non-regulated affiliates.

At December 31, 2008, internal borrowings outstanding within our utility money pool included (in thousands):

Utility Subsidiary	Borrowings Outstanding at December 31, 2008	
Black Hills Utility Holdings	$	61,432
Black Hills Power		67,920
Cheyenne Light		3,982

Registration Statements

Our articles of incorporation authorize the issuance of 100 million shares of common stock, $1 par value, and 25 million shares of preferred stock, no-par value. As of December 31, 2008, we had approximately 38.6 million shares of common stock outstanding, and no shares of preferred stock outstanding. The Company has an effective automatic shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our finance arrangements and restrictions imposed by federal and state regulatory authorities. As of December 31, 2008, we had not issued any securities under this shelf registration statement.

Anticipated Financing Plans

Enserco Facility

We are currently pursuing a renewal of the $300 million Enserco Facility with our existing lenders and other banks prior to its May 8, 2009 expiration. We also intend to change the facility to a committed facility upon its renewal.

Because of the uncommitted nature of the existing Enserco Facility, and given the current condition of the credit markets, we are conducting our Enserco business operations in a manner to preserve liquidity, which includes minimizing our utilization of the facility.

The Enserco Facility may be impacted by the current global credit crisis. The credit crisis is prompting most commercial banks to reduce their commitments or deleverage their portfolios. Consequently, some of the participating banks in the Enserco Facility may decline to participate in new credit transactions going forward. If a bank declined to participate in the facility, the existing issued letters of credit would remain in place; however, the remaining capacity available would be reduced by that bank's pro rata participation under the facility for future transactions.

The two largest participating banks under the Enserco Facility are Fortis Capital Corp. and BNP Paribas, which have participation levels of $105 million and $75 million, respectively. In October 2008, BNP Paribas announced that it had agreed to acquire Fortis' operations in Belgium and Luxembourg and its international banking franchises, including Fortis Capital Corp. In February 2009, the Fortis shareholders voted down the proposed transaction. Consequently, we cannot predict whether the two entities will continue to participate in the Enserco Facility at their current levels, regardless of whether or not a potential transaction is completed.

Factors Influencing Liquidity

Due to recent market conditions and the decline in the fair value of our pension plan assets, the funding status of our pension plan in 2009 is likely to deteriorate as compared to 2008. The final determination of pension plan contributions for 2009 and future periods is subject to multiple variables, most of which are beyond our control, including further changes to the fair value of the pension assets and changes in actuarial assumptions (in particular, the discount rate used in determining the projected benefit obligation). As a result, we may be required to contribute material amounts to our pension plans in 2009 and future periods, which could materially affect our liquidity and results of operations.

Many of our operations are subject to seasonal fluctuations in cash flow. We have traditionally sourced (i) variations in the working capital needs of our subsidiaries with cash on hand and capacity available under our credit facilities, and (ii) the capital expenditures of our subsidiaries through a combination of internally generated cash and equity contributions to our subsidiaries from us (financed primarily with net proceeds of equity and long-term debt issuances by us) and, in limited instances, debt offerings by our subsidiaries. Increased volatility in commodity prices and interest rates, magnified by the recent turmoil in the bank and capital markets, has made it more difficult for us to adequately forecast the liquidity needs of our subsidiary operations and our ability to raise capital for our subsidiaries on reasonable terms. Moreover, based on general market conditions and various predictions of a prolonged recession, we face an increasing risk of higher payment defaults by our customers. As a result, our liquidity needs are subject to greater fluctuation and are more difficult to forecast than in the past.

To the extent we issue long-term debt securities or arrange new credit facilities or extensions of existing credit lines in the bank loan market, we expect to pay significant fees in connection with these activities. In particular, future banking fees for new credit facilities or additional maturity extensions may be significantly more costly.

Although our Utility operations are subject to regulatory lag in terms of recovering capital expenditures and other prudently-incurred costs, revenues from our Utility operations traditionally have been stable. In light of volatile commodity prices and the potential of a severe economic recession, our cash flows from Utility operations could be less stable going forward.

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. For example, the issuance of debt by our utility subsidiaries (including the ability of Black Hills Utility Holdings to issue debt) and the use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located.

As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders.

Credit Ratings

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing, and vendor payment terms, including collateral requirements. As of December 31, 2008, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

Rating Agency	Rating	Outlook
Moody's	Baa3	Stable
S&P	BBB-	Stable
Fitch	BBB	Stable

In addition, the first mortgage bonds issued by Black Hills Power were rated at December 31, 2008 as follows:

Rating Agency	Rating	Outlook
Moody's	Baa1	Stable
S&P	BBB	Stable
Fitch	A-	Stable

We do not have any trigger events (i.e., an acceleration of repayment of outstanding indebtedness, an increase in interest costs or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings or other trigger events. If our senior unsecured credit rating should drop below investment grade, pricing under our credit agreements would be affected, increasing annual interest expense (pre-tax) by approximately $2.6 million based on our December 31, 2008 debt balances.

We have an interest rate swap with a notional amount of $50.0 million which has collateral requirements based upon our corporate credit ratings. At our current credit ratings, we would be required to post collateral for any amount by which the swap's negative mark-to-market fair value exceeds $(20.0) million. If our senior unsecured credit rating would drop to BB+ or below by S&P, or Ba1 or below by Moody's, we would be required to post collateral for the entire amount of the swap's negative market-to-market fair value.

Capital Requirements

Our primary capital requirements for the three years ended December 31 were as follows:

	2008	2007	2006
		(in thousands)	
Acquisition costs:			
Payment for acquisition of net assets, net of cash acquired	$ 938,423 (1)	$ –	$ –
Property additions:			
Utilities –			
Electric Utilities	186,237 (2)	104,963	132,340
Gas Utilities	19,337 (3)	–	–
Non-regulated Energy –			
Oil and Gas	89,169 (3)	72,153	158,846 (3)
Power Generation	5,105	128	1,142
Coal Mining	25,190	4,991	5,807
Energy Marketing	22	177	928
Corporate	11,033	22,316 (4)	1,972
	336,093	204,728	301,035
Discontinued operations investing activities	29,836 (5)	62,319 (5)	7,415
	1,304,352	267,047	308,450
Common stock dividends	53,663	50,300	43,960
Maturities/redemptions of long-term debt	130,297	62,109	36,518
Discontinued operations financing activities	73,928	12,858	32,753
	$ 1,562,240	$ 392,314	$ 421,681

(1) Cash paid for the Aquila properties, net of cash acquired.
(2) Includes $99.3 million for Wygen III construction.
(3) Includes $16.9 million for acquisition of a non-operated interest in Wyoming in 2008 and $75.4 million in 2006 for acquisitions in the Piceance Basin in Colorado.
(4) Includes $19.1 million for Aquila acquisition and development costs.
(5) Includes $27.8 million and $62.2 million in 2008 and 2007, respectively, for the construction of the Valencia plant, which was sold in the IPP Transaction.

Our capital additions for 2008 were $365.9 million, exclusive of the $938.4 million payment for the Aquila Transaction. Capital expenditures were primarily for construction of the Wygen III power plant, acquisition of non-operated oil and gas interests in Wyoming, development drilling of oil and gas properties, increased coal mining equipment and maintenance capital.

Our capital additions for 2007 were $267.0 million. Capital expenditures were primarily for the construction of the Wygen II power plant, the Valencia power plant, which is reclassified to Discontinued operations, development drilling of oil and gas properties, capitalized costs associated with the Aquila Transaction, and maintenance capital.

Our capital additions for 2006 were $308.5 million. Capital expenditures were primarily for construction of the Wygen II power plant, acquisitions and development drilling of oil and gas properties, and maintenance capital.

Forecasted Capital Expenditures

Forecasted capital requirements for maintenance capital and development capital are as follows:

(in thousands)	2009	2010	2011
Utilities:			
Electric Utilities[(1)(2)(3)]	$ 178,280	$ 107,900	$ 95,960
Gas Utilities	42,510	46,000	49,700
Non-regulated Energy:			
Oil and Gas[(4)]	38,620	40,020	35,770
Power Generation	3,930	1,710	1,460
Coal Mining	6,590	11,810	8,950
Energy Marketing	4,140	20	14
Corporate	13,340	7,510	6,230
	$ 287,410	$ 214,970	$ 198,084

(1) Electric Utilities capital requirements include approximately $61.5 million and $16.3 million for the development of the Wygen III coal-fired plant in 2009 and 2010, respectively. Forecasted expenditures assume we retain a 75% ownership interest in the plant.

(2) Electric Utilities capital requirements include approximately $17.9 million for Wygen III-related transmission projects in 2009.

(3) Capital expenditures for our Electric Utilities do not include any expenditures associated with our pending Colorado Electric Energy Resource Plan. This plan proposes construction of up to five gas generating plants to serve the Colorado Electric customers.

(4) Development capital for our oil and gas properties is expected to be limited to no more than the cash flows produced by those properties. Continued low commodity prices make many of our development drilling sites uneconomical, which could further reduce our development capital expenditures.

Contractual Obligations and Commitments

The following information is provided to summarize our cash obligations and commercial commitments at December 31, 2008:

		Payments Due by Period			
(in thousands)		Less Than	1-3	4-5	After 5
Contractual Obligations	Total	1 Year	Years	Years	Years
Long-term debt[(a)(b)]	$ 503,458	$ 2,078	$ 36,240	$ 235,360	$ 229,780
Unconditional purchase obligations[(c)]	1,092,241	259,671	582,157	109,437	140,976
Operating lease obligations[(d)]	10,314	3,703	4,107	1,114	1,390
Capital leases[(e)]	49	20	29	–	–
Other long-term obligations[(f)]	40,160	–	–	–	40,160
Employee benefit plans[(g)]	62,836	22,785	13,671	8,870	17,510
Liability for unrecognized tax benefits in accordance with FIN 48[(h)]	59,410	–	32,808	12,559	14,043
Credit facilities[(i)]	703,800	703,800	–	–	–
Total contractual cash obligations[(j)]	$2,472,268	$ 992,057	$ 669,012	$ 367,340	$ 443,859

(a) Long-term debt amounts do not include discounts or premiums on debt.

(b) In addition the following amounts are required for interest payments on long-term debt over the next five years: $33.8 million in 2009, $32.4 million in 2010, $31.0 million in 2011, $30.8 million in 2012 and $23.3 million in 2013. Variable rate interest using applicable rates is calculated as of December 31, 2008.

(c) Unconditional purchase obligations include the capacity costs associated with our power purchase agreement with PacifiCorp, the capacity and energy costs associated with our power purchase agreement with PSCo, and certain transmission, gas purchase and gas transportation and storage agreements. The energy charge under the purchase power agreement and the commodity price under the gas purchase contract are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2008 and price assumptions using existing prices at December 31, 2008. The pricing for the PSCo power purchase agreement is based on annual contracted capacity and an 85% load factor at current FERC approved rates. Our transmission obligations are based on filed tariffs as of December 31, 2008. Actual future costs under the variable rate contracts may differ materially from the estimates used in the above table.

(d) Includes operating leases associated with several office buildings and call centers, a lease for compressor equipment and vehicle leases.

(e) Represents a capital lease on office equipment.

(f) Includes our asset retirement obligations associated with our Oil and Gas, Coal Mining and Electric and Gas Utilities segments as discussed in Note 8 to the Notes to Consolidated Financial Statements in this Annual Report.

(g) Represents estimated employer contributions to employee benefit plans through the year 2018.

(h) Years 1-3 includes an estimated reversal of approximately $22.9 million of gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction.

(i) Includes $321.0 million on our corporate credit facility and $382.8 million on our Acquisition Facility.

(j) Amounts in the above table exclude any obligation that may arise from our derivatives, including interest rate swaps and commodity related contracts that have a negative fair value at December 31, 2008. These amounts have been excluded as it is impracticable to reasonably estimate the final amount and/or timing of any associated payments.

Dividends

Our dividend payout ratio for the year ended December 31, 2008, was 51% compared to 52% and 55% for the years ended December 31, 2007 and 2006, respectively. Dividends paid on our common stock totaled $1.40 per share in 2008, as compared to $1.37 per share in 2007 and $1.32 per share in 2006. Our three-year annualized dividend growth rate was 3.03%, and all dividends were paid out of operating cash flows.

In January 2009, our Board of Directors declared a quarterly dividend of $0.355 per share. If this dividend is maintained throughout 2009, it will be equivalent to $1.42 per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects.

Due to our holding company structure, substantially all of our operating cash flow is provided by dividends paid or distributions made by our subsidiaries. As a result, certain statutory limitations could affect dividend levels. Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in capital accounts. The cash to pay dividends to our shareholders is derived in part from dividends received from our utility subsidiaries. Our utility subsidiaries are generally limited in the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company.

OFF-BALANCE SHEET ARRANGEMENTS

Guarantees

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2008, we had guarantees totaling $83.4 million in place. Of the $83.4 million, $77.0 million was related to performance obligations under subsidiary contracts and $6.4 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 19 to Consolidated Financial Statements in this Annual Report.

As of December 31, 2008, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2008	Year Expiring
Guarantee obligations of Enserco under an agency agreement	$ 7,000	2009
Guarantees for payment of obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings	70,000	Ongoing
Indemnification for subsidiary reclamation/surety bonds	6,377	Ongoing
	$ 83,377	

Variable Interest Entities

In 2003, our Black Hills Wyoming subsidiary entered into an agreement with Wygen Funding, Limited Partnership (the variable interest entity) to lease the Wygen I plant. We were considered the “primary beneficiary” of this arrangement and, therefore, we included the VIE in our consolidated financial statements. The initial term of the lease was five years and included a purchase option equal to the adjusted acquisition cost, which was essentially equal to the cost of the plant. We guaranteed the obligations of Black Hills Wyoming under the lease agreement.

At the end of the initial lease term in June 2008, we elected to purchase the Wygen I plant at an adjusted acquisition cost of $133.1 million. In conjunction with this purchase, we retired $128.3 million of Wygen I project debt through borrowings on our revolving credit facility, and extinguished the $111.0 million guarantee obligation under the Wygen I lease. Since the plant and its financial activities were previously consolidated into our financial statements, the transaction had minimal impact on our consolidated financial statements.

Cash Flow Activities

2008

Cash flows from operations of $145.6 million decreased $110.6 million from the prior year amount, affected by a $127.4 million decrease in income from continuing operations and by the following:

- A $98.5 million decrease in cash flows from the change in operating assets and liabilities. The primary changes include changes in working capital accounts and current tax effects of both the IPP Transaction and the Aquila Transaction;
- Higher depreciation, depletion and amortization expense of $35.5 million;
- A $94.4 million pre-tax unrealized loss related to interest rate swaps marked-to-market through earnings; and
- A $91.8 million pre-tax ceiling test impairment charge to write down the net carrying value of our natural gas and crude oil properties due to low year-end commodity prices.

We had cash outflows from investing activities of $457.1 million, including:

- The acquisition costs of $938.4 million for the Aquila Transaction; and
- Approximately $328.9 million of property, plant and equipment additions. Significant additions during 2008 included approximately $99.3 million for Wygen III, approximately $75.3 million for development drilling at our oil and gas properties, and $16.9 million for the acquisition of an additional non-operated interest in a Wyoming oil and gas property

Partially offsetting the cash outflows from investing activities was $835.6 million of cash received for the IPP Transaction.

We had cash inflows from financing activities of $398.7 million primarily due to the following:

- A $382.8 million increase in borrowings under the Acquisition Facility, in conjunction with the Aquila Transaction; and
- A $284.0 million increase in borrowings on our revolving bank facility.

Partially offsetting the cash inflows from financing activities were the following:

- The payment of $53.7 million of cash dividends on common stock;
- Repayment of $130.3 million of long-term debt, including $128.3 million for the Wygen I project level debt; and
- Repayment of $73.9 million for Colorado IPP project-level debt, which was retired as part of the IPP Transaction and is included in financing activities of discontinued operations.

2007

In 2007, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common stock, to pay our scheduled long-term debt maturities and to fund a portion of our property additions.

Cash flows from operations of $256.3 million decreased $4.0 million from the prior year amount, affected by a $20.0 million increase in income from continuing operations and the following:

- A $28.6 million increase in cash flows from the change in current operating assets and liabilities. This was primarily driven by decreases in cash flow resulting from changes in net accounts receivable and accounts payable, which were more than offset by $26.2 million more in cash flows due to changes in materials, supplies and fuel during the year. Fluctuations in our materials, supplies and fuel balances were largely the result of natural gas inventory held by our Energy Marketing company in the form of storage agreements;
- A $32.1 million decrease from the net change in derivative assets and liabilities primarily from derivatives associated with normal operations of our gas and oil marketing business and related commodity price fluctuations;
- Higher depreciation, depletion and amortization expense of $4.3 million; and
- A decrease in cash flows resulting from the change in net regulatory assets and liabilities of $28.3 million primarily related to fuel cost adjustments for Cheyenne Light.

We had cash outflows from investing activities of $264.5 million, including:

- Approximately $47.0 million for construction expenditures for Wygen II;
- Expenditures associated with oil and gas properties of approximately $72.9 million;
- Capitalized costs of approximately $19.1 million related to the Aquila acquisition;
- Approximately $13.6 million for construction expenditures for Wygen III;
- Approximately $52.6 million of property, plant and equipment additions including ongoing maintenance capital in the normal course of business; and
- Approximately $56.0 million for construction expenditures for the Valencia IPP plant, which is included in investing activities of discontinued operations.

We had cash inflows from financing activities of $51.9 million primarily due to the following:

- Cash proceeds of $150.8 million from the issuance of common stock; and
- Cash proceeds of $110.0 million from the issuance of First Mortgage Bonds by Cheyenne Light.

Partially offsetting the cash inflows from financing activities were the following:

- Net payment of $108.5 million on our credit facility;
- Payment of $50.3 million of cash dividends on common stock; and
- Payment of $35.0 million including the call of our outstanding debt with GE Capital of $23.5 million, as well as long-term debt maturities.

Market Risk Disclosures

Our activities expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and counterparty risk. We have developed policies, processes, systems, and controls to manage and mitigate these risks.

Market risk is the potential loss that might occur as a result of an adverse change in market price or rate. We are exposed to the following market risks:

- Commodity price risk associated with our marketing business, our natural long position with crude oil and natural gas reserves and production, and fuel procurement for certain of our gas-fired generation assets;
- Interest rate risk associated with our variable rate credit facilities and our project financing floating rate debt as described in Notes 7 and 8 of our Notes to Consolidated Financial Statements; and
- Foreign currency exchange risk associated with our natural gas marketing business transacted in Canadian dollars.

Our exposure to these market risks is affected by a number of factors including the size, duration, and composition of our energy portfolio, the absolute and relative levels of interest rates, currency exchange rates and commodity prices, the volatility of these prices and rates, and the liquidity of the related interest rate and commodity markets.

To manage and mitigate these identified risks, we have adopted the BHCRPP. These policies have been approved by our Executive Risk Committee and reviewed by our Board of Directors. These policies include governance, control infrastructure, authorized commodities and trading instruments, prohibited activities, employee conduct, etc. The Executive Risk Committee, which includes senior level executives, meets on a regular basis to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

TRADING ACTIVITIES

Natural Gas and Crude Oil Marketing

We have a natural gas and crude oil marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in the western and mid-continent regions of the United States and Canada. For producer services our main objective is to provide value in the supply chain by acting as the producer's "marketing arm" for wellhead purchases, scheduling services, imbalance management, risk management services and transportation management. We accomplish this goal through industry experience, extensive contacts, transportation and risk management expertise, trading skills and personal attention. Our end-use origination efforts focus on supplying and providing electricity generators and industrial customers with flexible options to procure their energy inputs and asset optimization services to these large end-use consumers of natural gas. Our wholesale marketing activity has two functions: support the efforts of producer services and end-use origination groups, and marketing and trading natural gas and crude oil.

To effectively manage our producer services, end-use origination and wholesale marketing portfolios, we enter into forward physical commodity contracts, financial derivative instruments including over-the-counter swaps and options and storage and transportation agreements.

We conduct our gas marketing business activities within the parameters as defined and allowed in the BHCRPP and further delineated in the gas marketing Risk Management Policies and Procedures as approved by our Executive Risk Committee.

Monitoring and Reporting Market Risk Exposures

We use a number of quantitative tools to measure, monitor and limit our exposure to market risk in our natural gas and oil marketing portfolio. We limit and monitor our market risk through established limits on the nominal size of positions based on type of trade, location and duration. Such limits include those on fixed price, basis, index, storage, transportation and foreign exchange positions.

Our market risk limits are monitored by our Risk Management function to ensure compliance with our stated risk limits. The Risk Management function operates independently from our Energy Marketing Group. The limits are measured, monitored and regularly reported to and reviewed by our Executive Risk Committee.

Daily risk management activities include reviewing positions in relation to established position limits, assessing changes in daily mark-to-market and other non-statistical risk management techniques.

The contract or notional amounts, terms and mark-to-market values of our natural gas and crude oil marketing and derivative commodity instruments at December 31, 2008 and 2007, are set forth in Note 2 to the Consolidated Financial Statements in this Annual Report.

Non-Regulated Trading Activities

The following table provides a reconciliation of activity in our natural gas and crude oil marketing portfolio that has been recorded at fair value including market value adjustments on inventory positions that have been designated as part of a fair value hedge during the year ended December 31, 2008 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2007	$ 3,718 [(a)]
Net cash settled during the period on positions that existed at December 31, 2007	26,410
Change in fair value due to change in assumptions	1,898
Unrealized gain on new positions entered during the period and still existing at December 31, 2008	49,541
Realized loss on positions that existed at December 31, 2007 and were settled during the period	(33,890)
Change in cash collateral[(b)]	(15,027)
Unrealized loss on positions that existed at December 31, 2007 and still exist at December 31, 2008	(4,203)
Total fair value of energy marketing positions at December 31, 2008	$ 28,447 [(a)]

[(a)] The fair value of energy marketing positions consists of derivative assets/liabilities held at fair value in accordance with SFAS 157 and market value adjustments to natural gas inventory that has been designated as a hedged item as part of a fair value hedge in accordance with SFAS 133, as follows (in thousands):

	December 31, 2008	December 31, 2007
Net derivative assets	$ 54,117	$ 14,797
Cash collateral	(16,315)	(1,287)
Market adjustment recorded in material, supplies and fuel	(9,355)	(9,792)
	$ 28,447	$ 3,718

[(b)] We adopted FSP FIN 39-1 effective January 1, 2008. See Note 2 to the Consolidated Financial Statements in this Annual Report.

Therefore, the above reconciliation does not present a complete picture of our overall portfolio of trading activities or our expected cash flows from energy trading activities. In our natural gas and crude oil marketing operations, we often employ strategies that include utilizing derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, SFAS 133 generally does not allow us to mark our inventory, transportation or storage positions to market. The result is that while a significant majority of our energy marketing positions are fully economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions should be expected given these accounting requirements.

We adopted the provisions of SFAS 157 on January 1, 2008. SFAS 157 provides a single definition of fair value and establishes a fair value hierarchy which requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. We use the fair value methodology outlined in SFAS 157 to value the assets and liabilities for our outstanding derivative contracts. See Note 3 to the Consolidated Financial Statements in this Annual Report.

The sources of fair value measurements were as follows (in thousands):

	Maturities		
Source of Fair Value	Less than 1 year	1 – 2 years	Total Fair Value
Level 1	$ (16,315)	$ –	$ (16,315)
Level 2	42,342	633	42,975
evel 3	11,142	–	11,142
Market value adjustment for inventory (see footnote (a) above)	(9,355)	–	(9,355)
Total	$ 27,814	$ 633	$ 28,447

The following table presents a reconciliation of our energy marketing positions recorded at fair value under GAAP to a non-GAAP measure of the fair value of our energy marketing forward book wherein all forward trading positions are marked-to-market:

(in thousands)	December 31, 2008	December 31, 2007
Fair value of our energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$ 28,447	$ 3,718
Market value adjustments for inventory, storage and transportation positions that are not marked-to-market under GAAP	45,192	24,952
Fair value of all forward positions (non-GAAP)	73,639	28,670
Cash collateral included in GAAP marked-to-market fair value	16,315	1,287
"Liquidity reserve" included in GAAP marked-to-market fair value[(1)]	–	1,898
Fair value of all forward positions excluding cash collateral and "Liquidity reserve" (non-GAAP)	$ 89,954	$ 31,855

[(1)] In accordance with GAAP and industry practice prior to the issuance of SFAS 157, we included a "liquidity reserve" in our GAAP marked-to-market fair value. This "liquidity reserve" accounted for the estimated impact of the bid/ask spread in a liquidation scenario under which we are forced to liquidate our forward book on the balance sheet date. As a result of our adoption of SFAS 157, the Company discontinued its use of a "liquidity reserve" in valuing the total forward position within its energy marketing portfolio. See Note 3 of the Consolidated Financial Statements in this Annual Report.

ACTIVITIES OTHER THAN TRADING

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. Our reserves are natural “long” positions, or unhedged open positions, and introduce commodity price risk and variability in our cash flows. We employ risk management methods to mitigate this commodity price risk and preserve our cash flows. We have adopted guidelines covering hedging for our natural gas and crude oil production. These guidelines have been approved by our Executive Risk Committee and reviewed by our Board of Directors.

To mitigate commodity price risk and preserve cash flows, we primarily use over-the-counter swaps and options. Our hedging policy allows up to 75% of our natural gas and 100% of our crude oil production from proven producing reserves to be hedged for a period up to two years in the future. Our hedging strategy is conducted from an enterprise-wide risk perspective; accordingly, we might not externally hedge a portion of our natural gas production when we have offsetting price risk for the fuel requirements of certain of our power generating activities.

The Company has entered into agreements to hedge a portion of its estimated 2009 and 2010 natural gas and crude oil production. The hedge agreements in place are as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)	Price
San Juan El Paso	01/04/2007	Swap	04/08 – 03/09	2,500	$ 6.93
San Juan El Paso	01/04/2007	Swap	04/08 – 03/09	1,000	$ 6.96
San Juan El Paso	01/05/2007	Swap	01/09 – 03/09	1,500	$ 7.51
San Juan El Paso	02/12/2007	Swap	01/09 – 03/09	5,000	$ 7.87
San Juan El Paso	04/25/2007	Swap	04/09 – 06/09	2,500	$ 7.21
San Juan El Paso	04/26/2007	Swap	04/09 – 06/09	2,500	$ 7.15
San Juan El Paso	05/09/2007	Swap	04/09 – 06/09	5,000	$ 7.24
CIG	05/09/2007	Swap	04/09 – 06/09	2,000	$ 6.87
CIG	05/09/2007	Swap	01/09 – 03/09	2,000	$ 8.37
San Juan El Paso	07/27/2007	Swap	07/09 – 09/09	5,000	$ 7.63
CIG	09/07/2007	Swap	07/09 – 09/09	1,500	$ 6.48
AECO	09/07/2007	Swap	04/08 – 10/09	1,000	$ 6.89
San Juan El Paso	10/29/2007	Swap	07/09 – 09/09	5,000	$ 7.38
San Juan El Paso	10/29/2007	Swap	10/09 – 12/09	5,000	$ 7.53
CIG	10/29/2007	Swap	10/09 – 12/09	1,500	$ 7.07
NWR	11/16/2007	Swap	01/09 – 12/09	1,500	$ 6.87
San Juan El Paso	12/13/2007	Swap	10/09 – 12/09	1,500	$ 7.39
San Juan El Paso	12/13/2007	Swap	10/09 – 12/09	1,500	$ 7.41
CIG	01/03/2008	Swap	01/10 – 03/10	2,000	$ 7.49
NWR	01/03/2008	Swap	01/10 – 03/10	1,500	$ 7.50
AECO	01/03/2008	Swap	11/09 – 03/10	1,000	$ 8.07
San Juan El Paso	01/23/2008	Swap	01/10 – 03/10	5,000	$ 7.50
San Juan El Paso	02/28/2008	Swap	01/10 – 03/10	3,000	$ 8.55
San Juan El Paso	04/09/2008	Swap	04/10 – 06/10	5,000	$ 7.26
San Juan El Paso	04/30/2008	Swap	04/10 – 06/10	2,500	$ 7.65
AECO	08/20/2008	Swap	04/10 – 06/10	1,000	$ 7.73
San Juan El Paso	08/20/2008	Swap	07/10 – 09/10	5,000	$ 7.74
AECO	08/20/2008	Swap	07/10 – 09/10	1,000	$ 7.88
AECO	10/24/2008	Swap	10/10 – 12/10	1,000	$ 7.05
San Juan El Paso	12/19/2008	Swap	10/09 – 12/09	1,000	$ 5.12
San Juan El Paso	12/19/2008	Swap	04/10 – 06/10	1,500	$ 5.39
San Juan El Paso	12/19/2008	Swap	07/10 – 09/10	3,000	$ 5.95
San Juan El Paso	12/19/2008	Swap	10/10 – 12/10	5,000	$ 5.89
CIG	01/26/2009	Swap	04/10 – 06/10	2,000	$ 4.45
CIG	01/26/2009	Swap	07/10 – 09/10	2,000	$ 4.47
CIG	01/26/2009	Swap	10/10 – 12/10	2,000	$ 4.68
CIG	01/26/2009	Swap	01/11 – 03/11	2,000	$ 6.00
NWR	01/26/2009	Swap	01/11 – 03/11	2,000	$ 6.05
San Juan El Paso	01/26/2009	Swap	01/11 – 03/11	5,000	$ 6.38
San Juan El Paso	02/13/2009	Swap	01/11 – 03/11	2,500	$ 6.16
San Juan El Paso	02/13/2009	Swap	10/10 – 12/10	3,000	$ 5.35
NWR	02/13/2009	Swap	04/10 – 12/10	1,000	$ 4.20

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	03/23/2007	Swap	01/09 – 03/09	5,000	$ 67.60
NYMEX	03/28/2007	Swap	01/09 – 03/09	5,000	$ 69.00
NYMEX	04/12/2007	Put	01/09 – 03/09	5,000	$ 65.00
NYMEX	04/26/2007	Swap	04/09 – 06/09	5,000	$ 70.25
NYMEX	05/10/2007	Swap	04/09 – 06/09	5,000	$ 69.10
NYMEX	05/29/2007	Put	04/09 – 06/09	5,000	$ 65.00
NYMEX	06/22/2007	Swap	07/09 – 09/09	5,000	$ 72.10
NYMEX	07/27/2007	Put	07/09 – 09/09	5,000	$ 65.00
NYMEX	09/12/2007	Swap	07/09 – 09/09	5,000	$ 71.20
NYMEX	09/12/2007	Put	01/09 – 03/09	5,000	$ 70.00
NYMEX	09/12/2007	Put	04/09 – 06/09	5,000	$ 70.00
NYMEX	10/29/2007	Put	10/09 – 12/09	5,000	$ 75.00
NYMEX	10/29/2007	Swap	10/09 – 12/09	5,000	$ 80.75
NYMEX	11/16/2007	Put	07/09 – 09/09	5,000	$ 75.00
NYMEX	11/16/2007	Put	10/09 – 12/09	5,000	$ 75.00
NYMEX	01/03/2008	Put	01/10 – 03/10	5,000	$ 80.00
NYMEX	01/03/2008	Swap	01/10 – 03/10	5,000	$ 88.70
NYMEX	01/23/2008	Swap	10/09 – 12/09	5,000	$ 83.10
NYMEX	01/23/2008	Swap	01/10 – 03/10	5,000	$ 82.90
NYMEX	02/28/2008	Put	01/10 – 03/10	5,000	$ 85.00
NYMEX	04/09/2008	Swap	04/10 – 06/10	5,000	$ 99.60
NYMEX	04/30/2008	Put	04/10 – 06/10	5,000	$ 85.00
NYMEX	05/29/2008	Put	04/10 – 06/10	5,000	$ 105.00
NYMEX	07/16/2008	Swap	04/10 – 06/10	5,000	$ 135.10
NYMEX	07/16/2008	Swap	07/10 – 09/10	5,000	$ 134.90
NYMEX	08/20/2008	Put	07/10 – 09/10	5,000	$ 90.00
NYMEX	09/03/2008	Put	07/10 – 09/10	5,000	$ 90.00
NYMEX	10/24/2008	Put	07/10 – 09/10	5,000	$ 60.00
NYMEX	12/05/2008	Swap	10/10 – 12/10	5,000	$ 65.20
NYMEX	01/26/2009	Swap	10/10 – 12/10	5,000	$ 60.15
NYMEX	01/26/2009	Swap	01/11 – 03/11	5,000	$ 60.90
NYMEX	02/13/2009	Swap	01/11 – 03/11	5,000	$ 60.05

The hedge agreements entered into by the Company had a fair value of approximately $26.4 million as of December 31, 2008.

Power Generation

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. These short positions can arise from unplanned plant outages or from unanticipated load demands. To control such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities and purchased power resources exceed our anticipated load requirements plus a required reserve margin.

FINANCING ACTIVITIES

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. At December 31, 2008, we had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 8 years. These swaps have been designated as hedges in accordance with SFAS 133 and accordingly their mark-to-market adjustments are recorded in “Accumulated other comprehensive loss” on the Consolidated Balance Sheet.

We also have interest rate swaps with a notional amount of $250.0 million which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were originally designated as cash flow hedges in accordance with SFAS 133 and the mark-to-market value was recorded in “Accumulated other comprehensive loss” on the Consolidated Balance Sheet. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined that the forecasted long-term debt financings were probable of not occurring in the time period originally specified and as a result, the swaps are no longer effective hedges in accordance with SFAS 133 and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the income statement and during the fourth quarter of 2008 we recorded a $94.4 million pre-tax unrealized mark-to-market charge to earnings. These swaps are ten and twenty year swaps which have amended mandatory early termination dates ranging from September 30, 2009 to December 29, 2009.

Further details of the swap agreements are set forth in Note 2 to the Consolidated Financial Statements in this Annual Report.

On December 31, 2008 and 2007, our interest rate swaps and related balances were as follows (in thousands):

December 31, 2008	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax Income (Loss)
Interest rate swaps	$ 150,000	5.04%	8.00	$ –	$ –	$ 5,740	$ 22,495	$ (28,235)	$ –
Interest rate swaps	$ 250,000	5.67%	1.00	$ –	$ –	$ 94,440	$ –	$ –	$ (94,440)
	$ 400,000			$ –	$ –	$ 100,180	$ 22,495	$ (28,235)	$ (94,440)
December 31, 2007									
Interest rate swaps	$ 150,000	5.04%	8.75	$ –	$ –	$ 1,792	$ 4,274	$ (6,066)	$ –
Interest rate swaps	250,000	5.54%	0.50	–	–	16,600	–	(16,600)	–
	$ 400,000			$ –	$ –	$ 18,392	$ 4,274	$ (22,666)	$ –

Based on December 31, 2008 market interest rates and balances, a loss of approximately $5.7 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

On July 3, 2007, Cheyenne Light entered into a $110.0 million treasury lock to hedge a $110.0 million First Mortgage Bond offering which was completed in November 2007. The treasury lock cash settled on October 15, 2007, the pricing date of the offering, and resulted in a $4.3 million payment to the counterparty. The payment was recorded as a regulatory asset and will be amortized over the life of the related bonds as additional interest expense.

The table below presents principal (or notional) amounts and related weighted average interest rates by year of maturity for our long-term debt obligations, including current maturities (in thousands):

	2009	2010	2011	2012	2013	Thereafter	Total
Long-term debt							
Fixed rate [(a)]	$ 2,078	$ 32,096	$ 2,116	$ 2,028	$ 226,955	$ 218,330	$ 483,603
Average interest rate	9.62%	8.16%	9.70%	9.53%	6.52%	6.91%	6.85%
Variable rate	$ –	$ –	$ –	$ –	$ –	$ 19,855	$ 19,855
Average interest rate	–	–	–	–	–	3.93%	3.93%
Total long-term debt	$ 2,078	$ 32,096	$ 2,116	$ 2,028	$ 226,955	$ 238,185	$ 503,458
Average interest rate	9.62%	8.16%	9.70%	9.53%	6.52%	6.67%	6.73%

[(a)] Excludes unamortized premium or discount.

CREDIT RISK

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We have adopted the BHCCP that establishes guidelines, controls, and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, our Executive Credit Committee, which includes senior executives, meets on a regular basis to review our credit activities and to monitor compliance with the adopted policies.

For our energy marketing, production, and generation activities, we seek to mitigate our credit risk by conducting a majority of our business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements, and securing our credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by our review of their current credit information. We maintain a provision for estimated credit losses based upon our historical experience and any specific customer collection issue that we have identified. While most credit losses have historically been within our expectations and provisions established, we cannot provide assurance that we will continue to experience the same credit loss rates that we have in the past, or that an investment grade counterparty will not default sometime in the future.

At December 31, 2008, our credit exposure (exclusive of retail customers of our regulated utility segments) was concentrated primarily with investment grade companies. Approximately 90% of our credit exposure was with investment grade companies. The remaining credit exposure is with non-investment grade or non-rated counterparties, of which a portion was supported through letters of credit, prepayments, or parental guarantees.

FOREIGN EXCHANGE CONTRACTS

Our natural gas and crude oil marketing subsidiary conducts its business in the United States and Canada. Transactions in Canada are generally transacted in Canadian dollars, which creates exchange rate risk. To mitigate this risk, we enter into forward currency exchange contracts to offset earnings volatility from changes in exchange rates between the Canadian and United States dollars. At December 31, 2008 and 2007, we had outstanding forward exchange contracts to purchase approximately $52.0 million and $28.0 million Canadian dollars, respectively. These contracts had a fair value of $(0.2) million and $(0.3) million at December 31, 2008 and 2007, respectively, and have been recorded as Derivative assets/liabilities on the accompanying Consolidated Balance Sheets. All forward exchange contracts outstanding at December 31, 2008 were settled by January 26, 2009.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 1 to the Consolidated Financial Statements in this Annual Report for information on new accounting standards adopted in 2008 or pending adoption.

Safe Harbor for Forward-Looking Information

This Annual Report includes "forward-looking statements" as defined by the SEC. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this Annual Report that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions that we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties that, among other things, could cause actual results to differ materially from those contained in the forward-looking statements, including:

- Our ability to obtain adequate cost recovery for our utility operations through regulatory proceedings and receive favorable rulings in periodic applications to recover costs for fuel and purchased power in our regulated utilities;
- Our ability to obtain permanent financing for the Aquila Transaction and other capital expenditures on reasonable terms;
- Our ability to successfully integrate and profitably operate any recent and future acquisitions;
- Our ability to receive regulatory approval from the CPUC for our proposed construction of new power generation facilities for Colorado Electric;
- The amount and timing of capital deployment in new investment opportunities or for the repurchase of debt or stock;
- Our ability to successfully maintain our corporate credit rating;
- Our ability to complete the permitting, construction, start-up and operation of power generating facilities in a cost-effective and timely manner;
- The timing, volatility and extent of changes in energy and commodity prices, supply or volume, the cost and availability of transportation of commodities, changes in interest or foreign exchange rates, and the demand for our services, any of which can affect our earnings, our financial liquidity and the underlying value of our assets;
- Our ability to meet production targets for our oil and gas properties, which may be dependent upon issuance by federal, state and tribal governments, or agencies thereof, of drilling, environmental and other permits, and the availability of specialized contractors, work force and equipment, or the possibility of reductions in our drilling program resulting from the current economic climate and commodity prices, which also may prevent us from maintaining production rates and replacing reserves for our oil and gas properties;
- Our ability to accurately estimate demand from our customers for natural gas;
- Our ability to provide accurate estimates of proved oil and gas reserves, coal reserves and future production rates and associated costs;
- The extent of our success in connecting natural gas supplies to gathering, processing and pipeline systems;
- The timing and extent of scheduled and unscheduled outages of power generation facilities;
- The possibility that we may be required to take impairment charges to reduce the carrying value of some of our long-lived assets when indicators of impairment emerge;
- The possibility that we may be required to take impairment charges under the SEC's full cost ceiling test for the accumulated costs of our natural gas and oil reserves;
- Changes in business and financial reporting practices arising from the enactment of the EPA 2005 and subsequent rules and regulations promulgated thereunder;
- Our ability to effectively use derivative financial instruments to hedge commodity, currency exchange rate and interest rate risks;
- Our ability to minimize losses related to defaults on amounts due from customers and counterparties, including counterparties to trading and other commercial transactions;
- The amount of collateral required to be posted from time to time in our transactions;
- Our ability to comply, or to make expenditures required to comply, with changes in laws and regulations, particularly those relating to taxation, safety and protection of the environment;
- Our ability to recover those expenditures in customer rates, where applicable;
- Our ability to recover our borrowing costs, including debt service costs, in our customer rates;
- Liabilities for environmental conditions, including remediation and reclamation obligations, under environmental laws;
- Changes in state laws or regulations that could cause us to curtail our independent power production or exploration and production activities;
- Weather and other natural phenomena;
- Macro- and micro-economic changes in the economy and energy industry, including the impact of (i) consolidations and changes in competition, (ii) changing conditions in the capital and credit markets, which affect our ability to raise capital on favorable terms, and (iii) general economic and political conditions, including tax rates or policies and inflation rates;
- The effect of accounting policies issued periodically by accounting standard-setting bodies;
- The cost and effects on our business, including insurance, resulting from terrorist actions or responses to such actions or events;
- The outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements on our financial condition or results of operations; and
- Price risk due to marketable securities held as investments in benefit plans.

New factors that could cause actual results to differ materially from those described in forward-looking statements emerge from time to time, and it is not possible for us to predict all such factors, or the extent to which any such factor or combination of factors may cause actual results to differ from those contained in any forward-looking statement. We assume no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events or otherwise.

Management's Report on Internal Control over Financial Reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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.

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2008, based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation we have concluded that our internal control over financial reporting was effective as of December 31, 2008.

Our assessment of the effectiveness of our internal controls over financial reporting as of December 31, 2008 excluded the assets and operations acquired on July 14, 2008 in the Aquila Transaction, which are doing business as Black Hills Energy. Such exclusion was in accordance with SEC guidance that an assessment of a recently acquired business may be omitted in management's report on internal control over financial reporting, provided the acquisition took place within twelve months of management's evaluation. Collectively, Black Hills Energy comprised 38% of our consolidated assets at December 31, 2008, 37% of our consolidated revenues and 4% of our net income for the year ended December 31, 2008. Our disclosure controls and procedures were not materially impacted by the acquisition.

Deloitte & Touche, LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation's financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of December 31, 2008. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

BLACK HILLS CORPORATION

Report Of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Black Hills Corporation
Rapid City, South Dakota

We have audited the internal control over financial reporting of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2008, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company'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, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

As described in Management's Report on Internal Control over Financial Reporting, management excluded from its assessment of internal control over financial reporting the assets and operations acquired on July 14, 2008 in the Aquila Transaction, which are doing business as Black Hills Energy. Collectively, Black Hills Energy comprised 38% of total assets, 37% of revenues, and 4% of net income of the consolidated financial statement amounts as of and for the year ended December 31, 2008. Accordingly, our audit did not include the internal control over financial reporting of Black Hills Energy.

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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, 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 by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and the financial statement schedule as of and for the year ended December 31, 2008, of the Company and our report dated March 2, 2009, expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's adoption of new accounting standards.

DELOITTE & TOUCHE LLP

Minneapolis, MN
March 2, 2009

Report Of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Black Hills Corporation
Rapid City, South Dakota

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule listed in the Index at Item 15. 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 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 audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Black Hills Corporation and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such 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.

The Company adopted Financial Accounting Standard Board's (FASB) Emerging Issues Task Force Issue No. 04-6, Accounting for Stripping Costs Incurred during Production in the Mining Industry, on January 1, 2006, Statement of Financial Accounting Standard (SFAS) No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106, and 132(R), on December 31, 2006, and Financial Accounting Standards Board Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109, on January 1, 2007.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 2, 2009, expressed an unqualified opinion on the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

Minneapolis, MN
March 2, 2009

BLACK HILLS CORPORATION
Consolidated Statements Of Income

Years ended December 31,	2008	2007	2006
(in thousands)			
Revenues:			
Operating revenues	$ 1,005,790	$ 574,838	$ 542,585
Operating expenses:			
Fuel and purchased power	449,742	161,006	191,651
Operations and maintenance	121,264	68,755	62,732
Administrative and general	138,568	111,337	88,562
Depreciation, depletion and amortization	107,263	71,767	67,515
Taxes, other than income taxes	41,294	32,943	29,989
Impairment of long-lived assets (Notes 1 and 12)	91,782	3,315	–
	949,913	449,123	440,449
Operating income	55,877	125,715	102,136
Other income (expense):			
Interest expense	(54,123)	(25,181)	(29,946)
Interest rate swap (Note 2)	(94,440)	–	–
Interest income	2,176	3,565	1,764
Allowance for funds used during construction - equity	3,835	4,803	2,647
Other expense	(187)	(347)	(132)
Other income	1,064	761	753
	(141,675)	(16,399)	(24,914)
Income (loss) from continuing operations before minority interest and income taxes	(85,798)	109,316	77,222
Equity in earnings (loss) of unconsolidated subsidiaries	4,366	(1,231)	1,653
Minority interest	(130)	(377)	(510)
Income tax benefit (expense)	29,395	(32,427)	(23,103)
Income (loss) from continuing operations	(52,167)	75,281	55,262
Income from discontinued operations, net of income taxes	157,247	23,491	25,757
Net income available for common stock	$ 105,080	$ 98,772	$ 81,019
Earnings (loss) per share of common stock:			
Basic-			
Continuing operations	$ (1.37)	$ 2.03	$ 1.67
Discontinued operations	4.12	0.63	0.77
Total	$ 2.75	$ 2.66	$ 2.44
Diluted-			
Continuing operations	$ (1.37)	$ 2.01	$ 1.65
Discontinued operations	4.12	0.63	0.77
Total	$ 2.75	$ 2.64	$ 2.42
Weighted average common shares outstanding:			
Basic	38,193	37,024	33,179
Diluted	38,193	37,414	33,549

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

BLACK HILLS CORPORATION

Consolidated Balance Sheets

At December 31,	2008	2007
ASSETS	(in thousands, except share amounts)	
Current assets:		
Cash and cash equivalents	$ 168,491	$ 76,889
Restricted cash	–	5,443
Accounts receivable (net of allowance for doubtful accounts of $6,751 and $4,588, respectively)	357,404	268,462
Materials, supplies and fuel	118,021	88,580
Derivative assets	73,068	35,921
Income tax receivable	20,269	–
Deferred income taxes	10,244	4,512
Regulatory assets	35,390	2,307
Other current assets	16,380	10,391
Assets of discontinued operations	246	572,731
	799,513	1,065,236
Investments	22,764	19,216
Property, plant and equipment	2,705,492	1,847,435
Less accumulated depreciation and depletion	(683,332)	(509,187)
	2,022,160	1,338,248
Other assets:		
Goodwill	359,290	11,482
Intangible assets, net	4,884	3
Derivative assets	9,799	2,492
Regulatory assets	143,705	18,692
Other	17,774	14,265
	535,452	46,934
	$ 3,379,889	$ 2,469,634

BLACK HILLS CORPORATION

Consolidated Balance Sheets

LIABILITIES AND STOCKHOLDERS' EQUITY	(in thousands, except share amounts)	
Current liabilities:		
Accounts payable	$ 288,907	$ 239,177
Accrued liabilities	134,940	96,207
Derivative liabilities	118,657	39,380
Accrued income taxes	–	833
Regulatory liabilities	5,203	4,779
Notes payable	703,800	37,000
Current maturities of long-term debt	2,078	130,326
Liabilities of discontinued operations	88	91,233
	1,253,673	638,935
Long-term debt, net of current maturities	501,252	503,301
Deferred credits and other liabilities:		
Deferred income taxes	223,607	207,735
Derivative liabilities	22,025	9,375
Regulatory liabilities	38,456	28,303
Benefit plan liabilities	159,034	41,699
Other	131,306	65,264
	574,428	352,376
Minority interest	–	5,167
Commitments and contingencies (Notes 7, 8, 9, 13, 17, 18 and 19)		
Stockholders' equity:		
Common stock equity-		
Common stock $1 par value; 100,000,000 shares authorized; issued:		
38,676,054 shares at 2008 and 37,842,221 shares at 2007	38,676	37,842
Additional paid-in capital	584,582	560,475
Retained earnings	447,453	397,393
Treasury stock at cost –		
40,183 shares at 2008 and 45,916 shares at 2007	(1,392)	(1,347)
Accumulated other comprehensive loss	(18,783)	(24,508)
	1,050,536	969,855
	$ 3,379,889	$ 2,469,634

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

BLACK HILLS CORPORATION

Consolidated Statements Of Cash Flows

Years ended December 31,	2008	2007	2006
		(in thousands)	
Operating activities:			
Net income	$ 105,080	$ 98,772	$ 81,019
Income from discontinued operations, net of tax	(157,247)	(23,491)	(25,757)
Income (loss) from continuing operations	(52,167)	75,281	55,262
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities-			
Depreciation, depletion and amortization	107,263	71,767	67,515
Impairment of long-lived assets	91,782	3,315	–
Issuance of common stock and treasury stock for operating expense	2,657	4,585	2,760
Unrealized mark-to-market charge on certain interest rate swaps	94,440	–	–
Net change in derivative assets and liabilities	(36,847)	(12,354)	19,755
Deferred income taxes	2,058	31,409	33,233
Change in operating assets and liabilities-			
Materials, supplies and fuel	14,525	18,197	(8,042)
Accounts receivable and other current assets	(50,955)	(27,510)	(2,875)
Accounts payable and other current liabilities	(21,453)	49,897	22,919
Regulatory assets and liabilities	(35,874)	(9,433)	18,879
Other operating activities	12,159	6,562	12,272
Net cash provided by operating activities of continuing operations	127,588	211,716	221,678
Net cash provided by operating activities of discontinued operations	18,053	44,572	38,593
Net cash provided by operating activities	145,641	256,288	260,271
Investing activities:			
Property, plant and equipment additions	(328,922)	(205,213)	(301,034)
Payment for acquisition of net assets, net of cash acquired	(938,423)	–	–
Proceeds from sale of business operations	835,592	–	40,735
Other investing activities	4,537	(3,360)	(905)
Net cash used in investing activities of continuing operations	(427,216)	(208,573)	(261,204)
Net cash used in investing activities of discontinued operations	(29,836)	(55,908)	(7,469)
Net cash used in investing activities	(457,052)	(264,481)	(268,673)

BLACK HILLS CORPORATION

Consolidated Statements Of Cash Flows

Financing activities:			
Dividends paid on common stock	(53,663)	(50,300)	(43,960)
Common stock issued	2,683	150,787	3,213
Increase (decrease) in short-term borrowings, net	666,800	(108,500)	90,500
Long-term debt – issuance	–	110,000	–
Long-term debt – repayments	(130,297)	(35,033)	(4,302)
Other financing activities	(12,907)	(2,178)	(964)
Net cash provided by financing activities of continuing operations	472,616	64,776	44,487
Net cash used in financing activities of discontinued operations	(73,928)	(12,858)	(32,753)
Net cash provided by financing activities	398,688	51,918	11,734
Increase in cash and cash equivalents	87,277	43,725	3,332
Cash and cash equivalents:			
Beginning of year	81,255[(b)]	37,530[(c)]	34,198[(d)]
End of year	$ 168,532[(a)]	$ 81,255[(b)]	$ 37,530[(c)]
Supplemental disclosure of cash flow information:			
Non-cash investing and financing activities-			
Property, plant and equipment acquired with accrued liabilities	$ 23,067	$ 19,734	$ 25,022
Issuance of common stock for earn-out settlement (see Note 18)	$ 19,694	$ –	$ –
Cash paid during the period for-			
Interest (net of amount capitalized)	$ 55,864	$ 44,700	$ 48,905
Income taxes paid (refunded)	$ 32,988	$ 14,204	$ (2,685)

(a) Includes approximately $41,000 of cash included in assets of discontinued operation.
(b) Includes approximately $4.4 million of cash included in the assets of discontinued operations.
(c) Includes approximately $5.0 million of cash included in the assets of discontinued operations.
(d) Includes approximately $11.6 million of cash included in the assets of discontinued operations.

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

BLACK HILLS CORPORATION

Consolidated Statements Of Common Stockholders' Equity And Comprehensive Income

Year Ended December 31,	2008	2007	2006
		(in thousands, except share amounts)	
Common stock:			
Balance beginning of year	$ 37,842	$ 33,405	$ 33,223
Issuance of common stock	834	4,437	182
Balance end of year (38,676,054 shares, 37,842,221 shares and 33,404,902 shares issued in 2008, 2007 and 2006, respectively)	38,676	37,842	33,405
Additional paid-in capital:			
Balance beginning of year	560,475	409,826	404,035
Issuance of common stock	23,762	150,630	5,791
Issuance of treasury stock, net of purchases	345	19	–
Balance end of year	584,582	560,475	409,826
Retained earnings:			
Balance beginning of year	397,393	348,245	313,217
Net income	105,080	98,772	81,019
Dividends on common stock	(53,663)	(50,300)	(43,960)
Cumulative effect of change in accounting principle (see Notes 1, 14 and 17)	(1,357)	676	(2,031)
Balance end of year	447,453	397,393	348,245
Treasury stock:			
Balance beginning of year	(1,347)	(920)	(1,766)
(Purchase) issuance of treasury stock, net	(45)	(427)	846
Balance end of year (40,183 shares, 45,916 shares and 35,700 shares issued in 2008, 2007 and 2006, respectively)	(1,392)	(1,347)	(920)
Accumulated other comprehensive (loss):			
Balance beginning of year	(24,508)	(515)	(9,830)
Other comprehensive (loss) income, net of tax (see Note 15)	5,725	(23,993)	15,429
Adoption of accounting pronouncement (see Note 17)	–	–	(6,114)
Balance end of year	(18,783)	(24,508)	(515)
Total stockholders' equity	$ 1,050,536	$ 969,855	$ 790,041

Year Ended December 31,	2008	2007	2006
		(in thousands)	
Comprehensive income:			
Net income available for common stock	$ 105,080	$ 98,772	$ 81,019
Other comprehensive (loss) income, net of tax (see Note 15)	5,725	(23,993)	15,429
	$ 110,805	$ 74,779	$ 96,448

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

BLACK HILLS CORPORATION

Notes To Consolidated Financial Statements
December 31, 2008, 2007 and 2006

1 BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BUSINESS DESCRIPTION

Black Hills Corporation is a diversified energy company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, operates in two primary business groups: Utilities and Non-regulated Energy. The Utilities Group includes two financial reporting segments: Electric Utilities and Gas Utilities. Electric Utilities include the operating results of the regulated electric utility operations of Black Hills Power and Colorado Electric, and the regulated electric and natural gas utility operations of Cheyenne Light. Gas Utilities consist of the operating results of the regulated natural gas utility operations of Colorado Gas, Iowa Gas, Kansas Gas and Nebraska Gas.

The Non-regulated Energy Group includes four financial reporting segments: Oil and Gas, Power Generation, Coal Mining and Energy Marketing. Oil and Gas, which is conducted through BHEP and its subsidiaries, engages in oil and natural gas production activities. Power Generation, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in power generation activities. Coal Mining, which is conducted through WRDC, engages in coal mining activities. Energy Marketing, which is conducted through Enserco, engages in natural gas and crude oil marketing activities. All of these businesses are aggregated for reporting purposes as Black Hills Non-Regulated Holdings.

For further descriptions of our business segments, see Note 20.

On July 14, 2008, we completed the acquisition of a regulated electric utility in Colorado and regulated gas utilities in Colorado, Iowa, Kansas and Nebraska from Aquila. Effective as of the acquisition date, the assets and liabilities, results of operations and cash flows of the acquired utilities are included in our Consolidated Financial Statements. See Note 21 for additional information.

On July 11, 2008, we completed the sale of seven IPP plants. For all periods presented, amounts associated with the divested IPP plants have been classified as discontinued operations on the accompanying Consolidated Financial Statements. See Note 16 for additional information.

USE OF ESTIMATES

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and 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. The most significant estimates relate to allowance for uncollectible accounts receivable, unbilled revenues, market value of derivatives, intangible asset valuations and useful lives, long-lived asset values and useful lives, proved oil and gas reserve volumes, employee benefit plans, asset retirement obligations and contingencies related to taxes, legal and regulatory matters. Actual results could differ materially from those estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its wholly-owned and majority-owned subsidiaries. Generally, we use the equity method of accounting for investments of which we own between 20 and 50% and investments in partnerships under 20% if we exercise significant influence. In May 2003, our subsidiary, Black Hills Wyoming, entered into an agreement with Wygen Funding, LP (a VIE), to lease the Wygen I plant. We were considered the primary beneficiary of the plant and therefore, consolidated Wygen Funding under FIN 46(R). In June 2008, we purchased the Wygen I plant. Since the plant was previously consolidated into our financial statements, the transaction had minimal impact on our Consolidated Financial Statements.

All intercompany balances and transactions have been eliminated in consolidation except for revenues and expenses associated with regulated intercompany fuel sales in accordance with the provisions of SFAS 71. Total intercompany fuel sales not eliminated were $47.5 million, $13.2 million and $10.8 million in 2008, 2007 and 2006, respectively.

Our consolidated statements of income include operating activity of acquired companies beginning with their acquisition date.

We use the proportionate consolidation method to account for our working interests in oil and gas properties and for our ownership interest in the jointly owned Black Hills Power transmission tie, the Wyodak power plant and the BHEP gas processing plant. See Note 6 for additional information.

CASH EQUIVALENTS

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

MATERIALS, SUPPLIES AND FUEL

As of December 31, the following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets:

(in thousands)	2008	2007
Major Classification		
Materials and supplies	$ 32,580	$ 27,649
Fuel – Electric Utilities	10,058	5,025
Gas supply – Gas Utilities	59,529	–
Gas and oil held by Energy Marketing*	15,854	55,906
Total materials, supplies and fuel	$ 118,021	$ 88,580

* As of December 31, 2008 and 2007, market adjustments related to gas and oil held by Energy Marketing and recorded in inventory, were $(9.4) million and $(9.8) million, respectively. (See Note 2 for further discussion of Energy Marketing trading activities.)

The increase in gas supply is due to additions of natural gas storage inventory for the gas utilities acquired in July 2008.

Materials and supplies, Fuel – Electric Utilities, and Gas supply – Gas Utilities are valued on a weighted-average cost basis.

Gas and oil held by Energy Marketing primarily consists of gas held in storage and gas imbalances held on account with pipelines. Gas imbalances represent the differences that arise between volumes of gas received into the pipeline versus gas delivered off of the pipeline. Generally, natural gas and oil inventory is stated at the lower of cost or market on a weighted-average cost basis. To the extent that gas and oil held by Energy Marketing has been designated as the underlying hedged item in a fair value hedge transaction, those volumes are stated at market value using published industry quotations.

PROPERTY, PLANT AND EQUIPMENT

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a project. In addition, we also capitalize interest, when applicable, on undeveloped leasehold costs and certain non-regulated construction projects. The amount of AFUDC and interest capitalized was $8.0 million, $14.8 million and $7.2 million in 2008, 2007 and 2006, respectively. The cost of regulated electric property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage, is charged to accumulated depreciation. Removal costs associated with non-legal obligations are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets, except for oil and gas properties as described below, result in gains or losses recognized as a component of income. Ordinary repairs and maintenance of property are charged to operations as incurred.

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method on volumes produced and estimated reserves. For certain non-utility power plant components, a unit-of-production methodology based on plant hours run is used.

OIL AND GAS OPERATIONS

We account for our oil and gas activities under the full cost method. Under the full cost method, costs related to acquisition, exploration and estimated future expenditures to be incurred in developing proved reserves as well as estimated dismantlement and abandonment costs, net of estimated salvage values are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonment of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized.

Those costs directly associated with unproved properties and major development projects, if any, are excluded from the costs to be amortized. These excluded costs are subsequently included within the costs to be amortized when it is determined whether or not proved reserves can be assigned to the properties. The properties excluded from the costs to be amortized are assessed for impairment at least annually and any amount of impairment is added to the costs to be amortized.

Under the full cost method, net capitalized costs are subject to a ceiling test which limits these costs to the present value of future net cash flows discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the net capitalized costs. Future net cash flows are estimated based on end-of-period spot market commodity prices adjusted for contracted price changes. If the net capitalized costs exceed the full cost "ceiling" at period end, a permanent non-cash write-down would be charged to earnings in that period unless subsequent changes in facts, such as market price increases, eliminate or reduce the indicated write-down.

As a result of low crude oil and natural gas prices at December 31, 2008, we recorded a pre-tax non-cash ceiling test impairment of our oil and gas assets totaling $91.8 million. The write-down of gas and oil properties was based on December 31, 2008 NYMEX spot prices of $5.71 per Mcf, adjusted to $4.44 per Mcf at the wellhead, for natural gas; and $44.60 per barrel, adjusted to $32.74 per barrel at the wellhead, for crude oil. No ceiling test write-downs were recorded during 2007 or 2006.

Given the volatility of oil and gas prices, our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that another write-down of oil and gas properties could occur in the future.

GOODWILL AND INTANGIBLE ASSETS

We account for goodwill and intangible assets in accordance with SFAS 142. Under SFAS 142, goodwill and intangible assets with indefinite lives are not amortized but the carrying values are reviewed annually for impairment. Intangible assets with a finite life continue to be amortized over their estimated useful lives. We perform this annual review of goodwill and intangible assets during the fourth quarter of each year (or more frequently if impairment indicators arise).

The substantial majority of our goodwill and intangible assets are contained within the Utilities Group relating to the 2008 purchase of utility properties in the Aquila Transaction. Changes to goodwill and intangible assets during the years ended December 31, 2008 and 2007 are as follows (in thousands):

	Goodwill	Amortized Other Intangible Assets
Balance at December 31, 2006, net of accumulated amortization	$ 12,168	$ 402
Tax adjustment on acquisition earn-out (see Note 18)	(92)	–
Impairment losses	(594)	(314)
Amortization expense	–	(85)
Balance at December 31, 2007, net of accumulated amortization	11,482	3
Additions	347,808	4,919
Amortization expense	–	(38)
Balance at December 31, 2008, net of accumulated amortization	$ 359,290	$ 4,884

On July 14, 2008, we completed the acquisition of regulated electric and gas utilities from Aquila. Allocation of the purchase price included $344.5 million of goodwill and $4.9 million of intangible assets (see Note 21).

The acquisition of the Aquila assets has been accounted for under purchase accounting, whereby the purchase price of the transaction was allocated to identifiable assets acquired and liabilities assumed based upon their fair values. The estimates of the fair values recorded were determined based on the principles in SFAS 157 and reflect significant assumptions and judgments. We comply with the provisions of SFAS 71 and thus the assets and settlement of liabilities are subject to cost-based regulatory rate-setting processes. Accordingly, the historical carrying values of a majority of our assets and liabilities are deemed to represent fair values.

During 2008, we adjusted goodwill $3.3 million for issuance of shares of common stock related to the settlement of the Earn-out Litigation with former Indeck shareholders. See Notes 10 and 18 for additional information.

In accordance with SFAS 142, we tested goodwill for impairment in the fourth quarter. We estimated the fair value of the goodwill using discounted cash flow methodology and an analysis of comparable companies' transactions. This analysis required the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, and long-term earnings and merger multiples for comparable companies. We believe that the goodwill amount reflects the value of the relatively stable, long-lived cash flows of the regulated utility business, considering the regulatory environment and market growth potential.

Intangible assets represent easements, right-of-way and trademarks and are amortized using a straight-line method using estimated useful lives of 20 years. Intangible assets totaled $4.9 million, with accumulated amortization less than $0.1 million at December 31, 2008 and intangible assets totaled less than $0.1 million, net of accumulated amortization at December 31, 2007. Amortization expense for intangible assets was $0.1 million in each of 2008, 2007 and 2006, respectively. Amortization expense for existing intangible assets is expected to be $0.2 million a year through 2013.

During the third quarter of 2007, we wrote off intangible assets of $0.3 million, net of accumulated amortization of $0.8 million, related to the impairment of the Ontario plant. The impairment charge is a result of a thermal host contract expiration without a long-term extension. See Note 12 for additional information.

During the second quarter of 2007, we wrote off goodwill of approximately $0.1 million for tax adjustments related to the Indeck acquisition earn-out (see Note 18). During the fourth quarter of 2007, we wrote off goodwill of approximately $0.6 million, net of accumulated amortization of $0.1 million, related to the write-down of our investments in the Rupert and Glenns Ferry partnerships. The write-downs were the result of impairment charges by the partnerships primarily due to forecasted unhedged future commodity purchases during a significant portion of the remaining term of the partnerships' power supply agreements (see Note 12).

ASSET RETIREMENT OBLIGATIONS

We initially record liabilities for the present value of retirement costs for which the Company has a legal obligation, with an equivalent amount added to the asset cost. The asset is then depreciated or depleted over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations. For the Oil and Gas segment, differences in the settlement of the liability and the recorded amount are generally reflected as adjustments to the capitalized cost of oil and gas properties and depleted pursuant to our use of the full cost method.

IMPAIRMENT OF LONG-LIVED ASSETS

We periodically evaluate whether events and circumstances have occurred which may affect the estimated useful life or the recoverability of the remaining balance of our long-lived assets. If such events or circumstances were to indicate that the carrying amount of these assets was not recoverable, we would estimate the future cash flows expected to result from the use of the assets and their eventual disposition. If the sum of the expected future cash flows (undiscounted and without interest charges) was less than the carrying amount of the long-lived assets, we would recognize an impairment loss. In 2007, we recorded a $2.7 million pre-tax impairment charge to reduce the carrying value of the Ontario power plant and related intangibles and a $0.6 million pre-tax impairment charge of goodwill related to lower partnership earnings as a result of a partnership impairment charge for the Glenns Ferry and Rupert power plants, in which we hold a 50% interest and account for under the equity method.

DERIVATIVES AND HEDGING ACTIVITIES

We account for derivative and hedging activities in accordance with SFAS 133. SFAS 133 requires that derivative instruments be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

SFAS 133 allows hedge accounting for qualifying fair value and cash flow hedges. SFAS 133 provides that the gain or loss on a derivative instrument designated and qualifying as a fair value hedging instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk be recognized currently in earnings in the same accounting period. SFAS 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

CURRENCY ADJUSTMENTS

Our functional currency for all operations is the United States dollar. Through Enserco, we engage in natural gas business transactions in Canada and accordingly, have various transactions that have been denominated in Canadian dollars. These Canadian denominated transactions/balances are adjusted to United States dollars for financial reporting purposes using the year-end exchange rate for balance sheet items and an average exchange rate during the period for income statement items. Currency transaction gains or losses on transactions executed in Canadian dollars are recorded in Operating revenues on the accompanying Consolidated Statements of Income as incurred. The amount of unrealized gains was $0.3 million, $0.2 million and $0.3 million in 2008, 2007 and 2006, respectively, and the amount of realized losses was $1.4 million, $1.7 million and $1.0 million in 2008, 2007 and 2006, respectively.

DEFERRED FINANCING COSTS

Deferred financing costs are amortized using the effective interest method over the term of the related debt.

DEVELOPMENT COSTS

We generally expense, when incurred, development and acquisition costs associated with corporate development activities prior to acquiring or beginning construction of a project. Expensed development costs are included in Administrative and general operating expenses on the accompanying Consolidated Statement of Income. Upon adoption of SFAS 141(R) in 2009, all acquisition-related costs will be expensed in the periods in which the costs are incurred or services are rendered.

LEGAL COSTS

Litigation liabilities, including potential settlements are recorded when it is probable we are likely to incur liability or settlement costs, and those costs can be reasonably estimated. Litigation settlement accruals are recorded net of expected insurance recovery. Legal costs related to ongoing litigation are expensed as incurred.

MINORITY INTEREST IN SUBSIDIARIES

Minority interest in the accompanying Consolidated Statements of Income and Balance Sheets represents the non-affiliated equity investors' interest in Wygen Funding, L.P., a VIE as defined by FIN 46(R).

Earnings attributable to minority ownership are shown on the accompanying Consolidated Statements of Income on a pre-tax basis as the minority investor is a limited partnership which pays no tax at the corporate level.

REGULATORY ACCOUNTING

Our Utilities Group is subject to regulation by various state and federal agencies. The accounting policies followed are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by our non-regulated businesses.

The regulated utilities follow the provisions of SFAS 71, and their financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating the utilities. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply. In the event we determine that Black Hills Power, Cheyenne Light, Iowa Gas, Nebraska Gas, Kansas Gas, Colorado Gas or Colorado Electric no longer meets the criteria for following SFAS 71, the accounting impact to the Company could be an extraordinary non-cash charge to operations, which could be material.

On December 31, 2008 and 2007, we had the following regulatory assets and liabilities:

(in thousands)	2008	2007
Regulatory assets		
Deferred energy and fuel costs adjustments	$ 32,198	$ 1,931
Deferred gas cost adjustments and gas price derivatives	25,364	376
Allowance for funds used during construction	8,719	7,880
Employee benefit plans	98,414	2,998
Environmental	2,406	–
Asset retirement obligations	2,598	–
Bond issue cost	4,121	4,276
Other	5,275	3,538
	$ 179,095	$ 20,999
Regulatory liabilities		
Deferred energy and gas costs	$ 2,417	$ 4,779
Cost of removal	31,351	22,431
Employee benefit plans	1,513	1,738
Revenue subject to refund	2,786	–
Other	5,592	4,134
	$ 43,659	$ 33,082

Regulatory assets are primarily recorded for the probable future revenue to recover the costs associated with regulated utilities' defined benefit postretirement plans, future income taxes related to the deferred tax liability for the equity component of allowance for funds used during construction of utility assets and unrecovered energy and fuel costs.

- Cheyenne Light files monthly with the WPSC a GCA to be included in tariff rates. The GCA is based on forecasts of the upcoming gas costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively.
- Our gas utilities have PGA provisions that allow them to pass the cost of gas to their customers. In addition, as allowed by state utility commissions, we have entered into certain exchange traded natural gas futures and options to reduce our customers' underlying exposure to fluctuations in gas prices. To the extent that gas costs are under-recovered or over-recovered, they are recorded as regulatory assets or liabilities, respectively.
- AFUDC represents the approximate composite cost of borrowed funds and a return on equity used to finance a project. AFUDC for the years ended December 31, 2008, 2007 and 2006 was $6.6 million, $11.2 million, and $5.6 million, respectively. The equity component of AFUDC for 2008, 2007 and 2006 was $3.8 million, $4.8 million and $2.6 million, respectively. The borrowed funds component of AFUDC for 2008, 2007 and 2006 was $2.8 million, $6.4 million and $3.0 million, respectively. The equity component of AFUDC is included in Other income (expense), and the borrowed funds component of AFUDC is included in Interest expense on the accompanying Consolidated Statements of Income.
- Deferred energy and fuel cost adjustments represents the cost of electricity delivered to our electric utility customers in excess of current rates that will be recovered in future rates.
- Asset retirement obligations represent the estimated recoverable costs for legally required removal obligations. See Note 9 for additional details.
- In connection with SFAS 158, our Regulated Utilities reflect the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plans and post-retirement benefit plans as regulatory assets rather than in accumulated other comprehensive income. In connection with the Aquila Transaction, we recorded $29.7 million through the purchase price allocation.

Regulatory liabilities represent items we expect to pay to customers through probable future decreases in rates.

- Deferred energy costs related to decreases in purchased power, transmission and natural gas costs charged to Cheyenne Light customers through a PCA and GCA mechanism.
- Cost of removal for utility plant represents the estimated cumulative net provisions for future removal costs included in depreciation expense for which there is no legal removal obligation.
- Pension represents the cumulative excess of pension costs recovered in rates over pension expense recorded under SFAS 87.
- Revenues subject to refund represent revenues collected from customers under interim rate orders that may be refunded to customers pending the outcome of final rate orders.

INCOME TAXES

The Company and its subsidiaries file consolidated federal income tax returns. Income taxes for consolidated subsidiaries are allocated to the subsidiaries based on separate company computations of taxable income or loss.

We use the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. We classify deferred tax assets and liabilities into current and non-current amounts based on the classification of the related assets and liabilities.

We account for uncertainty in income taxes recognized in the financial statements in accordance with FIN 48. The unrecognized tax benefit is classified in Deferred credits and other liabilities, Other on the accompanying Consolidated Balance Sheet. See Note 14 for additional information.

REVENUE RECOGNITION

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price, delivery has occurred or services have been rendered, and collectibility is reasonably assured.

Utility revenues are based on authorized rates approved by the state regulatory agencies and FERC. Revenues related to the sale, transmission and distribution of energy delivery service are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on systematic meter readings throughout a month. Meters that are not read during a given month are estimated and trued-up to actual use in a future period. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and the corresponding unbilled revenue is recorded. The amount of unbilled revenues recorded in Accounts receivable on the Consolidated Balance Sheets as of December 31, 2008 and 2007 were $73.0 million and $5.8 million, respectively.

In addition, in accordance with SFAS 133 certain energy marketing activities are recorded at fair value as of the balance sheet date and net gains or losses resulting from the revaluation of these contracts to fair value are recognized currently in the results of operations. In accordance with EITF 02-3, all energy marketing contracts that do not meet the definition of derivatives as defined by SFAS 133, have been accounted for under the accrual method of accounting.

For long-term non-utility power sales agreements revenue is recognized either in accordance with EITF 91-6, or in accordance with SFAS 13 as appropriate. Under EITF 91-6, revenue is generally recognized as the lower of the amount billed or the average rate expected over the life of the agreement.

For our Investment in Associated Companies (see Note 4), which are involved in power generation, we use the equity method to recognize our pro rata share of the net income or loss of the associated company.

We present our operating revenues from energy marketing operations in accordance with the guidance provided in EITF 02-3 and EITF 99-19. Accordingly, gains and losses (realized and unrealized) on transactions at our natural gas and crude oil marketing operations are presented on a net basis in operating revenues, whether or not settled physically.

EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share from continuing operations is computed by dividing "Income from continuing operations" less preferred stock dividends, by the weighted average number of common shares outstanding during each year. Diluted earnings per share gives effect to all dilutive potential common shares outstanding during a period. A reconciliation of income from continuing operations and basic and diluted share amounts is as follows (in thousands):

	2008		2007		2006	
	(Loss)	Average Shares	Income	Average Shares	Income	Average Shares
Basic – Income (loss) from continuing operations	$ (52,167)	38,193	$ 75,281	37,024	$ 55,262	33,179
Dilutive effect of:						
Stock options	–	–	–	111	–	87
Contingent shares issuable for prior acquisition	–	–	–	159	–	159
Others	–	–	–	120	–	124
Diluted – Income (loss) from continuing operations	$ (52,167)	38,193	$ 75,281	37,414	$ 55,262	33,549

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive (in thousands):

	2008	2007	2006
Options to purchase common stock	–	34	153

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

EITF 04-6

The Company adopted EITF 04-6 on January 1, 2006. EITF 04-6 provides that stripping costs incurred in our mining operations should be included in the costs of inventory produced during the period the costs are incurred. Upon adoption of EITF 04-6 on January 1, 2006, the Company recorded a $2.0 million cumulative effect adjustment to write off previously recorded deferred charges with the offset decreasing retained earnings.

SFAS 157

During September 2006, the FASB issued SFAS 157. This Statement defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 does not expand the application of fair value accounting to any new circumstances, but applies the framework to other accounting pronouncements that require or permit fair value measurement. We apply fair value measurements to certain assets and liabilities, primarily commodity derivatives within our Energy Marketing and Oil and Gas segments, interest rate swap derivative instruments, and other miscellaneous derivatives.

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. As of January 1, 2008, we adopted the provisions of SFAS 157 for all assets and liabilities measured at fair value except for non-financial assets and liabilities measured at fair value on a non-recurring basis, as permitted by FSP FAS 157-2. As a result of adopting SFAS 157, we discontinued our use of a "liquidity reserve" in valuing the total forward positions within our energy marketing portfolio. This impact was accounted for prospectively as a change in accounting estimate and resulted in a $1.2 million after-tax benefit being recorded within our unrealized marketing margins. Unrealized margins are presented as a component of Operating revenues on the accompanying Consolidated Statements of Income. SFAS 157 also requires new disclosures regarding the level of pricing observability associated with instruments carried at fair value. This additional disclosure is provided in Notes 3 and 11.

FSP FAS 157-1

In February 2008, the FASB issued FSP FAS 157-1, which excludes SFAS 13 and other accounting pronouncements that address fair value for purposes of lease classification and measurement under SFAS 13 from SFAS 157 except when applying SFAS 157 to assets acquired and liabilities assumed in a business combination. We applied the provisions of FSP FAS 157-1 from the date of initial adoption of SFAS 157 on January 1, 2008. Accordingly, the provisions of SFAS 157 will not be applied to lease transactions under SFAS 13 except when applying SFAS 157 to business combinations.

FSP FAS 157-2

In February 2008, the FASB issued FSP FAS 157-2, which permits a one-year deferral of the application of SFAS 157 for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We adopted FSP FAS 157-2 effective January 1, 2008. Accordingly, the provisions of SFAS 157 will not be applied to non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis, until January 1, 2009. We are currently evaluating the impact, if any, that the deferred provisions of SFAS 157 will have on our consolidated financial statements.

SFAS 158

During September 2006, the FASB issued SFAS 158. This statement requires the recognition of the overfunded or underfunded status of defined benefit postretirement plans as an asset or liability in the statement of position, recognition of changes in the funded status in comprehensive income, measurement of the funded status of a plan as of the date of the year-end statement of financial position and provides for related disclosures. We applied the recognition provisions of SFAS 158 as of December 31, 2006. Effective for fiscal years ending after December 15, 2008, SFAS 158 requires the measurement of the funded status of the plan to coincide with the date of the year-end statement of financial position. In compliance with SFAS 158, the measurement date for the funded status of our pension and other postretirement benefit plans was changed to December 31 from September 30. See Note 17 for additional information.

SFAS 159

SFAS 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value, with changes in fair value recognized in earnings. SFAS 159 was adopted on January 1, 2008 and did not have an impact on our consolidated financial position, results of operations or cash flows.

FSP FIN 39-1

FSP FIN 39-1 amends certain paragraphs of FIN 39 to permit a reporting entity to offset fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007. We adopted FSP FIN 39-1 effective January 1, 2008. This standard changed our method of netting certain balance sheet amounts. We applied FSP FIN 39-1 as a change in accounting principle through retrospective application. Each Consolidated Balance Sheet herein reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when we believe a legal right of offset exists.

On July 11, 2008, the Company sold seven of its IPP plants. Amounts associated with the IPP plants divested have been classified as discontinued operations. Therefore this classification is also reflected in the Consolidated Balance Sheet and Consolidated Statement of Cash Flows.

Accordingly, December 31, 2007 and 2006 amounts have been reclassified to conform to this presentation as follows (in thousands):

Balance Sheet Line Description	Previously Reported at December 2007	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	Restated December 2007
Current assets:				
Receivables	$ 291,189	$ (1,945)	$ (20,782)	$ 268,462
Derivative assets	$ 37,208	$ (1,287)	$ –	$ 35,921
Current liabilities:				
Accounts payable	$ 242,813	$ (3,232)	$ (404)	$ 239,177

The affect on the Cash Flow Statements for 2007 and 2006 due to the reclassification are as follows (in thousands):

Cash Flow Statement Operating Activities Line Description	Previously Reported at December 2007	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	Restated December 2007
Accounts receivable and other current assets	$ (32,808)	$ 1,945	$ 3,353	$ (27,510)
Net change in derivative assets and liabilities	$ (10,763)	$ (1,591)	$ –	$ (12,354)
Accounts payable and other current liabilities	$ 49,258	$ (354)	$ 993	$ 49,897

Cash Flow Statement Operating Activities Line Description	Previously Reported at December 2007	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	Restated December 2006
Accounts receivable and other current assets	$ 2,208	$ (8,013)	$ 2,930	$ (2,875)
Net change in derivative assets and liabilities	$ 8,864	$ 10,891	$ –	$ 19,755
Accounts payable and other current liabilities	$ 28,853	$ (2,878)	$ (3,056)	$ 22,919

As of December 31, 2007 and 2006, we offset fair value cash collateral receivables and payables against net derivative positions in the amounts of $(1.3) million and $(2.9) million, respectively.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

SEC Final Rule #33-8995

On December 29, 2008, the SEC released Final Rule, "Modernization of Oil and Gas Reporting" amending the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technology advances. Key revisions include the ability to include non-traditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The amendment is effective January 1, 2010 and early adoption is not permitted. We are currently assessing the impact that the adoption will have on our disclosures, operating results, financial position and cash flows.

SFAS 141(R)

In December 2007, the FASB issued SFAS 141(R). SFAS 141(R) requires an acquiring entity to recognize the assets acquired, the liabilities assumed and any non-controlling interests in the acquiree at the acquisition date to be measured at their fair values as of the acquisition date, with limited exceptions specified in the statement. This replaces the cost allocation process in SFAS 141, which required the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. Acquisition-related costs will be expensed in the periods in which the costs are incurred or services are rendered. Costs to issue debt or equity securities shall be accounted for under other applicable GAAP. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after December 15, 2008. We expect SFAS 141(R) will have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of any acquisitions we consummate after the effective date. If income tax liabilities are settled for an amount other than as previously recorded prior to the adoption of SFAS 141(R), the reversal of any remaining liability will affect goodwill or the financial reporting basis in the applicable assets acquired. If previously recorded income tax liabilities acquired in a business combination reverse subsequent to the adoption of SFAS 141(R), such reversals will affect expense including income tax expense in the period of reversal. We are assessing the full impact SFAS 141(R) might have on future consolidated financial statements.

SFAS 160

In December 2007, the FASB issued SFAS 160. SFAS 160 amends ARB 51 and requires:

- Ownership interests in subsidiaries held by other parties other than the parent be clearly identified on the consolidated statement of financial position within equity, but separate from the parent's equity;
- Consolidated net income attributable to the parent and to the non-controlling interest be clearly identified on the face of the consolidated statement of income;
- Changes in a parent's ownership interest while the parent retains controlling financial interest be accounted for consistently as equity transactions;
- When a subsidiary is deconsolidated, any retained non-controlling equity investment in the former subsidiary be initially measured at fair value; and
- Sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners.

SFAS 160 is effective for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. We do not expect the adoption of SFAS 160 to have a significant effect on our consolidated financial statements.

SFAS 161

In March 2008, the FASB issued SFAS 161, which requires enhanced disclosures about how derivative and hedging activities affect an entity's financial position, financial performance and cash flows. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The adoption of SFAS 161 will require additional disclosures regarding our derivative instruments; however, it will not impact our financial position or results of operations.

FSP FAS 132(R)-1

During December 2008 the FASB issued FSP FAS 132(R)-1, which provides guidance on an employer's disclosures about plan assets in a defined benefit pension or other postretirement plan to provide users of financial statements with an understanding of:

- How investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies;
- The major categories of plan assets;
- The input and valuation techniques used to measure the fair value of plan assets;
- The effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and
- Significant concentrations of risk within plan assets.

FSP FAS 132(R)-1 is effective for fiscal years ending after December 15, 2009. We do not expect the adoption of FSP FAS 132(R)-1 to have a significant effect on our consolidated financial statements.

2 RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and unregulated energy sector expose the Company to a number of risks in the normal operations of its businesses. Depending on the activity, we are exposed to varying degrees of market risk and counterparty risk. We have developed policies, processes, systems, and controls to manage and mitigate these risks.

Market risk is the potential loss that might occur as a result of an adverse change in market price or rate. We are exposed to the following market risks:

- Commodity price risk associated with our marketing businesses, our natural long position with crude oil and natural gas reserves and production, fuel procurement for certain of our gas-fired generation assets and variability in revenue due to changes in gas usage at our Gas Utilities segment resulting from commodity price changes;
- Interest rate risk associated with variable rate credit facilities and project financing floating rate debt as described in Notes 7 and 8; and
- Foreign currency exchange risk associated with natural gas marketing business transacted in Canadian dollars.

Our exposure to these market risks is affected by a number of factors including the size, duration, and composition of our energy portfolio, the absolute and relative levels of interest rates, currency exchange rates and commodity prices, the volatility of these prices and rates, and the liquidity of the related interest rate and commodity markets.

TRADING ACTIVITIES

Natural Gas and Crude Oil Marketing

To manage our marketing portfolios, Enserco enters into forward physical commodity contracts, financial instruments including over-the-counter swaps and options, transportation agreements, storage agreements and forward foreign exchange contracts. The business activities of our Energy Marketing segment are conducted within the parameters as defined and allowed by the BHCRPP and the Gas and Oil Marketing Risk Policies and Procedures.

For the years ended December 31, 2008, 2007 and 2006, contracts and other activities at our natural gas and crude oil marketing operations are accounted for under the provisions of EITF 02-3 and SFAS 133. As such, all of the contracts and other activities at our natural gas and crude oil marketing operations that meet the definition of a derivative under SFAS 133 are accounted for at fair value. The fair values are recorded as either Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. The net gains or losses are recorded as Operating revenues in the accompanying Consolidated Statements of Income. EITF 02-3 precludes mark-to-market accounting for energy trading contracts that are not derivatives pursuant to SFAS 133. As part of our natural gas and crude oil marketing operations, we often employ strategies that include derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in limited circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, SFAS 133 generally does not allow us to mark inventory, transportation or storage positions to market. The result is that while a significant majority of our natural gas and crude oil marketing positions are economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions result from these accounting requirements.

The contract or notional amounts and terms of the natural gas and crude oil marketing and derivative commodity instruments at December 31, are set forth below:

	2008		2007	
	Notional Amounts	Latest expiration (months)	Notional Amounts	Latest expiration (months)
	(thousands of MMBtu)			
Natural gas basis swaps purchased	187,368	34	125,577	36
Natural gas basis swaps sold	186,710	34	128,892	36
Natural gas fixed-for-float swaps purchased	85,412	24	42,326	24
Natural gas fixed-for-float swaps sold	90,171	24	59,253	24
Natural gas physical purchases	131,937	16	90,583	15
Natural gas physical sales	145,706	21	98,888	27
Natural gas options purchased	1,440	3	3,472	10
Natural gas options sold	1,440	3	3,472	10
	(thousands of Bbls of oil)			
Crude oil physical purchases	7,446	12	4,991	12
Crude oil physical sales	6,251	12	3,800	12
Crude oil swaps purchased	435	24	495	12
Crude oil swaps sold	502	24	495	12
	(Dollars, in thousands)			
Canadian dollars purchased	$52,000	1	$28,000	2

Derivatives and certain natural gas and oil marketing activities were marked to fair value on December 31, 2008 and 2007, and the gains and/or losses recognized in earnings. The amounts related to the accompanying Consolidated Balance Sheets and Consolidated Statements of Income as of December 31, 2008 and 2007 are as follows (in thousands):

	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Cash Collateral Included in Derivative Asset/ Liabilities	Unrealized Gain
December 31, 2008	$ 52,723	$ (145)	$ 15,553	$ (777)	$ 16,315	$ 54,117
December 31, 2007	$ 30,999	$ 1,901	$ 16,908	$ 2,482	$ 1,287	$ 14,797

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in a “fair value” hedge transaction. These volumes include market adjustments based on published industry quotations. Market adjustments are recorded in inventory on the Consolidated Balance Sheets and the related unrealized gain/loss on the Consolidated Statements of Income effectively offsetting the earnings impact of the unrealized gain/loss recognized on the associated derivative asset or liability described above. As of December 31, 2008 and 2007, the market adjustments recorded in inventory were $(9.4) million and $(9.8) million, respectively.

ACTIVITIES OTHER THAN TRADING

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. Our natural “long” positions, or unhedged open positions, introduce commodity price risk and variability in our cash flows. We employ risk management methods to mitigate this commodity price risk and preserve cash flows and we have adopted guidelines covering hedging for our natural gas and crude oil production. These guidelines have been approved by our Executive Risk Committee, and are routinely reviewed by our Board of Directors.

Over-the-counter swaps and options are used to mitigate commodity price risk and preserve cash flows. These derivative instruments fall under the purview of SFAS 133 and we elect to utilize hedge accounting as allowed under this Statement.

At December 31, 2008 and 2007, we had a portfolio of swaps and options to hedge portions of our crude oil and natural gas production. These transactions were designated at inception as cash flow hedges, properly documented and initially met prospective effectiveness testing. At year-end, these transactions met retrospective effectiveness testing criteria and retained their cash flow hedge status.

At December 31, 2008 and 2007, the derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives was reported in other comprehensive income and the ineffective portion was reported in earnings.

On December 31, 2008 and 2007, we had the following swaps, options and related balances (in thousands):

	Notional*	Maximum Duration in Years**	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Earnings
December 31, 2008								
Crude oil swaps/options	435,000	0.25	$ 7,674	$ 3,464	$ –	$ 10	$ 9,642	$ 1,486
Natural gas swaps	8,523,500	1.00	11,828	3,749	–	297	15,280	–
			$ 19,502	$ 7,213	$ –	$ 307	$ 24,922	$ 1,486
December 31, 2007								
Crude oil swaps/options	495,000	1.00	$ 352	$ –	$ 3,506	$ 1,794	$ (5,300)	$ 352
Natural gas swaps	11,406,000	1.59	4,332	591	507	825	3,587	4
			$ 4,684	$ 591	$ 4,013	$ 2,619	$ (1,713)	$ 356

* Crude in Bbls, gas in MMBtu.

** Refers to the term of the derivative instrument. Assets and liabilities are classified as current/non-current based on the timing of the hedged transaction and the corresponding settlement of the derivative instrument.

Most of our crude oil and natural gas hedges are highly effective, resulting in limited earnings impact prior to realization. We estimate that a portion of the unrealized earnings currently recorded in accumulated other comprehensive income will be realized in earnings during 2009. Based on December 31, 2008 market prices, a $12.7 million gain will be realized and reported in earnings during 2009. These estimated realized gains for 2009 were calculated using December 31, 2008 market prices. Estimated and actual realized gains will likely change during 2009 as market prices change.

Regulated Gas Utilities

Our regulated gas utilities have PGA provisions that allow them to pass the cost of gas to the consumer. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. These adjustments are subject to periodic prudence reviews by the respective state utility commissions. In addition, as allowed or required by state utility commissions, we have entered into certain exchange traded natural gas futures and options transactions to reduce our customers' underlying exposure to fluctuations in gas prices. Gains and losses on the transactions are recorded as regulatory assets or liabilities. The futures and options transactions are considered derivative transactions under SFAS 133 and are marked-to-market and recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheet.

On December 31, 2008, the contract or notional amounts and terms of the natural gas derivative commodity instruments held by our Gas Utilities are as follows:

	Notional*	Latest Expiration (months)
Natural gas futures purchased	1,290,000	3
Natural gas options purchased	3,990,000	3
Natural gas options sold	820,000	3

* Gas in MMBtu

On December 31, 2008, our Gas Utilities held the following derivative-related balances (in thousands):

	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Regulatory Assets	Cash Collateral Included in Derivative Assets/ Liabilities
December 31, 2008	$ 4,224	$ –	$ 2,924	$ –	$ 11,668	$ 8,744

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations.

At December 31, 2008, we had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 8 years. We also had interest rate swaps with a notional amount of $250.0 million which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were originally designated as cash flow hedges in accordance with SFAS 133 and the mark-to-market values were recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheet. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined that the forecasted long-term debt financings were probable of not occurring in the time period originally specified and as a result, the swaps are no longer effective hedges in accordance with SFAS 133 and the hedge relationships were de-designated. Cumulative and future mark-to-market adjustments on the swaps are now recorded within the income statement. During the fourth quarter, we recorded an unrealized mark-to-market charge to earnings of $94.4 million pre-tax. These swaps are ten and twenty year swaps which have amended mandatory early termination dates ranging from September 30, 2009 to December 29, 2009.

On December 31, 2008 and 2007, our interest rate swaps and related balances were as follows (in thousands):

	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive (Loss)	Pre-tax (Loss)
December 31, 2008									
Interest rate swaps	$ 150,000	5.04%	8.00	$ –	$ –	$ 5,740	$ 22,495	$ (28,235)	$ –
Interest rate swaps	250,000	5.67%	1.00	–	–	94,440	–	–	(94,440)
	$ 400,000			$ –	$ –	$ 100,180	$ 22,495	$ (28,235)	$ (94,440)
December 31, 2007									
Interest rate swaps	$ 150,000	5.04%	8.75	$ –	$ –	$ 1,792	$ 4,274	$ (6,066)	$ –
Interest rate swaps	250,000	5.54%	0.50	–	–	16,600	–	(16,600)	–
	$ 400,000			$ –	$ –	$ 18,392	$ 4,274	$ (22,666)	$ –

Based on December 31, 2008 market interest rates and balances, a loss of approximately $5.7 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will change during the next twelve months as market interest rates change.

On July 3, 2007, Cheyenne Light entered into a $110.0 million treasury lock to hedge a $110.0 million First Mortgage Bond offering which was completed in November 2007. We cash settled the treasury lock on October 15, 2007, which was the pricing date of the offering. This settlement resulted in a $4.3 million payment to the counterparty. The payment was recorded as a regulatory asset and will be amortized over the life of the related bonds as additional interest expense.

Foreign Exchange Contracts

Enserco conducts its gas marketing business in the United States as well as Canada. Transactions in Canada are generally transacted in Canadian dollars and create exchange rate risk for us. To mitigate this risk, we enter into forward currency exchange contracts to offset earnings volatility from changes in exchange rates between the Canadian and United States dollars. At December 31, 2008 and 2007, we had outstanding forward exchange contracts to purchase approximately $52.0 million and $28.0 million Canadian dollars, respectively. These contracts had a fair value of $(0.2) million at December 31, 2008 and $(0.3) million at December 31, 2007, respectively, and have been recorded as Derivative assets/liabilities on the accompanying Consolidated Balance Sheets. The impact of foreign exchange transactions did not have a material effect on our Consolidated Statements of Income. All forward exchange contracts outstanding at December 31, 2008 were settled by January 26, 2009.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We adopted the BHCCP for the purpose of establishing guidelines, controls, and limits to manage and mitigate credit risk within risk tolerances established by our Board of Directors. In addition, we have a credit committee which includes senior executives that meet on a regular basis to review our credit activities and monitor compliance with our credit policies.

For energy marketing, production, and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements, and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

At December 31, 2008, our credit exposure (exclusive of retail customers of the regulated utilities) was concentrated primarily among investment grade companies. Approximately 90% of the credit exposure was with investment grade companies. The remaining credit exposure was with non-investment grade or non-rated counterparties, of which a portion was supported through letters of credit, prepayments or parental guarantees.

3 FAIR VALUE MEASUREMENTS

ADOPTION OF SFAS 157

Effective January 1, 2008, we adopted SFAS 157 as discussed in Note 1. SFAS 157 requires, among other things, enhanced disclosures about assets and liabilities carried at fair value. SFAS 157 also provides a single definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. As permitted under SFAS 157, we utilize a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing a significant portion of the assets and liabilities measured and reported at fair value.

SFAS 157 also requires enhanced disclosures and establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values giving the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). We are able to classify fair value balances based on the observability of inputs.

Financial assets and liabilities carried at fair value are classified and disclosed in one of the following three categories:

Level 1 – Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities and listed derivatives.

Level 2 – Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

The following table sets forth, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS 157, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect their placement within the fair value hierarchy levels.

	At Fair Value as of December 31, 2008				
Recurring Fair Value Measures (in thousands)	Level 1	Level 2	Level 3	Counterparty Netting [a]	Total
Assets:					
Commodity derivatives	$ 8,744	$ 267,932	$ 28,407	$ (217,696)	$ 87,387
Liabilities:					
Commodity derivatives	$ 16,315	$ 211,672	$ 12,009	$ (217,696)	$ 22,300
Foreign currency derivatives	–	227	–	–	227
Interest rate swaps	–	122,675	–	–	122,675
Total	$ 16,315	$ 334,574	$ 12,009	$ (217,696)	$ 145,202

[a] FIN 39 permits the netting of receivables and payables when a legally enforceable master netting agreement exists between the Company and a contractual counterparty.

The following table presents the changes in level 3 recurring fair value for the three and twelve months ended December 31, 2008 (in thousands):

Three Months Ended December 31, 2008	Commodity Derivatives	Short-term Investments	Total
Balance as of October 1, 2008	$ 6,321	$ 6,310	$ 12,631
Realized and unrealized gains	7,371	215	7,586
Purchases, issuance and (settlements)	2,706	(6,525)	(3,819)
Balances as of December 31, 2008	$ 16,398	$ –	$ 16,398
Changes in unrealized losses relating to instruments still held as of December 31, 2008	$ 6,527	$ 215	$ 6,742

Year Ended December 31, 2008	Commodity Derivatives
Balance as of January 1, 2008	$ 6,422
Realized and unrealized gains	11,059
Purchases, issuance and settlements	(1,083)
Balances as of December 31, 2008	$ 16,398
Changes in unrealized losses relating to instruments still held as of December 31, 2008	$ 1,886

Gains and losses (realized and unrealized) for level 3 commodity derivatives are included in Operating revenues on the Consolidated Statement of Income. We believe an analysis of commodity derivatives classified as level 3 needs to be undertaken with the understanding that these items may be economically hedged as part of a total portfolio of instruments that may be classified in level 1 or 2, or with instruments that may not be accounted for at fair value. Accordingly, gains and losses associated with level 3 balances may not necessarily reflect trends occurring in the underlying business. Further, unrealized gains and losses for the period from level 3 items may be offset by unrealized gains and losses in positions classified in level 1 or 2, as well as positions that have been realized during the quarter. Short-term investments included in level 3 represent auction rate securities held during 2008 but sold prior to December 31, 2008.

4 INVESTMENTS IN ASSOCIATED COMPANIES

Included in Investments on the accompanying Consolidated Balance Sheets are the following investments that have been recorded on the equity method of accounting:

- A 4.4% interest in Project Finance Fund III, L.P., which in turn has investments in numerous electric generating facilities in the United States and elsewhere. The carrying amount of our investment in the funds was $4.1 million and $3.0 million, as of December 31, 2008 and 2007, respectively. As of, and for the year ended December 31, 2008, the funds had assets of $22.4 million, liabilities of $0.1 million and net income of $10.0 million. As of, and for the year ended December 31, 2007, the funds had assets of $43.1 million, liabilities of $0.3 million and net income of $8.0 million. The Energy Investors Fund II, L.P. was fully liquidated as of December 31, 2008 and the Energy Investors Fund, L.P. was fully liquidated as of December 31, 2007. This investment is included in the Power Generation segment.

The power funds in which we invest apply the provisions of the AICPA Audit and Accounting Guide, "Audits of Investment Companies." This guidance among other things requires investments held by investment companies to be stated at fair value.

- A 50% interest in two natural gas-fired cogeneration facilities located in Rupert and Glenns Ferry, Idaho. The carrying amount in our investment was $0.8 as of December 31, 2008, and $0 million as of December 31, 2007. In December 2007, the Rupert and Glenns Ferry partnerships wrote down the carrying amounts of their property, plant and equipment to reflect the partnerships' assessment of the recoverability of their respective carrying amounts primarily due to forecasted unhedged future commodity purchases during a significant portion of the remaining term of power supply agreements. As a result, our carrying amount of the two partnership investments was reduced by a total of $3.9 million to reflect equity losses from the partnerships' asset impairment adjustments. In addition, we wrote off a total of $0.6 million of net goodwill for the two partnerships directly related to our 50% investments. This investment is included in the Power Generation segment. As of, and for the year ended December 31, 2008, these projects had assets of $6.4 million, liabilities of $6.0 million and net income of $3.4 million. As of, and for the year ended December 31, 2007, these projects had assets of $4.5 million, liabilities of $7.8 million and net income of $(11.6) million.

5 PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31, consisted of the following (in thousands):

UTILITIES GROUP Electric Utilities	2008	2008 Weighted Average Useful Life	2007	2007 Weighted Average Useful Life	Lives (in years)
Electric plant:					
Production	$ 531,872	46	$ 326,879	47	17-62
Transmission	94,115	45	73,383	45	35-56
Distribution	482,518	43	357,249	41	15-65
Plant acquisition adjustment	4,870	32	4,870	32	32
General	63,702	21	47,740	23	5-60
Total electric plant	1,177,077		810,121		
Less accumulated depreciation and amortization	303,273		276,646		
Electric plant net of accumulated depreciation and amortization	873,804		533,475		
Construction work in progress	169,759		200,804		
Net electric plant	$ 1,043,563		$ 734,279		

Gas Utilities	2008	2008 Weighted Average Useful Life	Lives (in years)
Gas plant:			
Production	$ 72	37	16-55
Transmission	23,299	54	22-60
Distribution	334,146	44	2-65
General	64,167	16	1-49
Total	421,684		
Less accumulated depreciation and amortization	13,328		
Total net of accumulated depreciation and amortization	408,356		
Construction work in progress	6,595		
Net Gas	$ 414,951		

2008 Non-regulated Energy		Property, Plant and Equipment		Less Accumulated Depreciation, Depletion and Amortization		Property, Plant and Equipment Net of Accumulated Depreciation		Construction Work in Progress		Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
Coal Mining	$	105,897	$	49,562	$	56,335	$	1,563	$	57,898	11	2-39
Oil and Gas		648,419		281,728		366,691		–		366,691	26	3-27
Energy Marketing		2,375		1,945		430		–		430	3	2-7
Power Generation		154,257		27,197		127,060		4,469		131,529	36	3-40
	$	910,948	$	360,432	$	550,516	$	6,032	$	556,548		

2007 Non-regulated Energy		Property, Plant and Equipment		Less Accumulated Depreciation, Depletion and Amortization		Property, Plant and Equipment Net of Accumulated Depreciation		Construction Work in Progress		Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
Coal Mining	$	81,046	$	45,587	$	35,459	$	5,675	$	41,134	15	3-25
Oil and Gas		559,394		153,050		406,344		–		406,344	24	3-25
Energy Marketing		2,389		1,603		786		–		786	4	2-7
Power Generation		155,208		24,294		130,914		20		130,934	35	3-40
	$	798,037	$	224,534	$	573,503	$	5,695	$	579,198		

2008		Property, Plant and Equipment		Less Accumulated Depreciation, Depletion and Amortization		Property, Plant and Equipment Net of Accumulated Depreciation		Construction Work in Progress		Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
Corporate	$	12,482	$	6,299	$	6,183	$	915	$	7,098	4	3-10

2007		Property, Plant and Equipment		Less Accumulated Depreciation, Depletion and Amortization		Property, Plant and Equipment Net of Accumulated Depreciation		Construction Work in Progress		Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
Corporate	$	19,474	$	8,007	$	11,467	$	13,304	$	24,771	4	3-10

6 JOINTLY OWNED FACILITIES

Our subsidiary, Black Hills Power, owns a 20% interest in the Wyodak Plant (the Plant), a 362 MW coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining 80% and operates the Plant. Black Hills Power receives 20% of the Plant's capacity and is committed to pay 20% of its additions, replacements and operating and maintenance expenses. As of December 31, 2008, Black Hills Power's investment in the Plant included $79.1 million in electric plant and $50.8 million in Accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. Black Hills Power's share of direct expenses of the Plant was $8.0 million; $7.3 million and $7.9 million for the years ended December 31, 2008, 2007 and 2006, respectively, and are included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. As discussed in Note 18, our Coal Mining subsidiary, WRDC, supplies PacifiCorp's share of the coal to the Plant under an agreement expiring in 2022. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC's coal reserves. Under the coal supply agreement, PacifiCorp is obligated to purchase a minimum of 1.5 million tons of coal each year of the contract term, subject to adjustment for planned outages. WRDC's sales to the Plant were $23.3 million, $21.5 million and $16.8 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Black Hills Power also owns a 35% interest in the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining 65%. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the tie is 400 MW – 200 MW West to East and 200 MW from East to West. Black Hills Power is committed to pay 35% of the additions, replacements and operating and maintenance expenses. For the twelve months ended December 31, 2008, 2007 and 2006, Black Hills Power's share of direct expenses was $0.1 million for each year. As of December 31, 2008 and 2007, Black Hills Power's investment in the transmission tie was $19.8 million, with $2.5 million and $2.0 million of accumulated depreciation, respectively, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets.

Through our BHEP subsidiary, we own a 44.7% non-operating interest in the Newcastle Gas Plant (the Gas Plant). The natural gas processing facility gathers and processes approximately 3,000 Mcf/day of gas, primarily from the Finn-Shurley Field in Wyoming. We receive our proportionate share of the Gas Plant's net revenues and are committed to pay our proportionate share of additions, replacements and operating and maintenance expenses. As of December 31, 2008, our investment in the Gas Plant included $4.1 million in plant and equipment and $3.6 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. Our share of revenues of the Gas Plant was $4.1 million, $2.8 million and $3.1 million for the years ended December 31, 2008, 2007 and 2006, respectively. Our share of direct expenses was $0.4 million, $0.3 million and $0.3 million for each of the years ended December 31, 2008, 2007 and 2006. These items are included in the corresponding categories of operating revenues and expenses in the accompanying Consolidated Statements of Income.

7 LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows (in thousands):

	2008	2007
Senior unsecured notes at 6.5% due 2013	$ 225,000	$ 225,000
Unamortized discount on notes	(128)	(157)
	224,872	224,843
First mortgage bonds:		
Electric Utilities		
Black Hills Power:		
8.06% due 2010	30,000	30,000
9.49% due 2018	2,810	3,100
9.35% due 2021	21,645	23,310
7.23% due 2032	75,000	75,000
Cheyenne Light:		
6.67% due 2037	110,000	110,000
Industrial development revenue bonds, variable rate, at 3.25% due 2021[(a)]	7,000	7,000
Industrial development revenue bonds, variable rate, at 3.25% due 2027[(a)]	10,000	10,000
	256,455	258,410
Other long-term debt:		
Pollution control revenue bonds at 4.8% due 2014	6,450	6,450
Pollution control revenue bonds at 5.35% due 2024	12,200	12,200
Other	3,353	3,460
	22,003	22,110
Project financing floating rate debt:		
Wygen I project at 5.76% due 2008	–	128,264
Total long-term debt	503,330	633,627
Less current maturities	(2,078)	(130,326)
Net long-term debt	$ 501,252	$ 503,301

[(a)] Interest rates are presented as of December 31, 2008.

Substantially all of the tangible utility property of Black Hills Power and Cheyenne Light is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of Black Hills Power and Cheyenne Light may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

Certain debt instruments of the Company and its subsidiaries contain restrictions and covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2008.

Scheduled maturities of long-term debt, excluding amortization of premium or discount, for the next five years are: $2.1 million in 2009, $32.1 million in 2010, $2.1 million in 2011, $2.0 million in 2012, $227.0 million in 2013 and $238.2 million thereafter.

8 NOTES PAYABLE

Black Hills Corporation had a committed line of credit with various banks totaling $525.0 million and $400.0 million at December 31, 2008 and 2007, respectively. Our $525.0 million credit line is a revolving credit facility, which expires May 4, 2010. The lenders' commitments under this credit facility were increased from $400.0 million to $525.0 million in July 2008. We had $321.0 million of borrowings and $60.7 million of letters of credit and $37.0 million of borrowings and $49.1 million of letters of credit issued under the facility at December 31, 2008 and 2007, respectively. The cost of borrowings or letters of credit issued under the facility is determined based on our credit ratings. At our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70 basis points over LIBOR (which equates to a 1.14% one-month borrowing rate as of December 31, 2008). We have no compensating balance requirements associated with this credit facility.

At December 31, 2008, Enserco also had a $300.0 million uncommitted, discretionary line of credit to provide support for its purchases of natural gas and crude oil. The line of credit is secured by all of Enserco's assets and expires on May 8, 2009. At December 31, 2008 and 2007, there were outstanding letters of credit issued under the facility of $126.5 million and $197.9 million, respectively, with no borrowing balances on the facility.

In May 2007, we entered into a senior unsecured $1 billion Acquisition Facility with ABN AMRO Bank N.V., as administrative agent, and other banks to fund the Aquila Transaction. In conjunction with the completion of the purchase of the Aquila properties, we executed a single draw of $382.8 million under the Acquisition Facility. The loan was originally scheduled to mature on February 5, 2009. However, on December 18, 2008, we amended the facility to extend the maturity date to December 29, 2009. Borrowings under this facility are available under a base rate option, which is based on the then-current prime rate, or under a LIBOR option, which is based on the then-current LIBOR plus an applicable margin. The amended applicable margin for base rate borrowings is 200 basis points and for LIBOR borrowings is 300 basis points, commencing the date of the amendment. Borrowing cost increases 50 basis points each calendar quarter beginning in the second quarter of 2009 until loan maturity. If our credit ratings, as assigned by S&P and Moody's, fall below investment grade, the applicable margin will increase by an additional 25 basis points.

Our credit facilities and debt securities contain certain restrictive financial covenants including, among others, interest expense coverage ratios, recourse leverage ratios and consolidated net worth ratios. At December 31, 2008, we were in compliance with these financial covenants. None of our facilities or debt securities contain default provisions pertaining to our credit ratings.

9 ASSET RETIREMENT OBLIGATIONS

SFAS 143 provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and requires that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. The associated ARO accretion expense is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71. We have identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells in the Oil and Gas segment, reclamation of coal mining sites at the Coal Mining segment and removal of fuel tanks, asbestos and transformers containing polychlorinated biphenyls at the Electric Utilities segment and asbestos at our Gas Utilities segment.

The following table presents the details of our ARO which are included on the accompanying Consolidated Balance Sheets in Other under Deferred credits and other liabilities (in thousands):

	Balance at 12/31/07	Liabilities Incurred	Liabilities Settled	Accretion	Balance at 12/31/08
Oil and Gas	$ 14,952	$ 5,029	$ (1,213)	$ 855	$ 19,623
Coal Mining	14,778	4,121	(1,839)	639	17,699
Electric Utilities	180	2,381*	–	55	2,616
Gas Utilities	–	213*	–	9	222
Total	$ 29,910	$ 11,744	$ (3,052)	$ 1,558	$ 40,160

* This balance was recorded as part of the purchase price allocation of the Aquila acquisition (see Note 21).

	Balance at 12/31/06	Liabilities Incurred	Liabilities Settled	Accretion	Balance at 12/31/07
Oil and Gas	$ 13,240	$ 1,934	$ (860)	$ 638	$ 14,952
Coal Mining	16,005	233	(1,748)	288	14,778
Electric Utilities	171	–	–	9	180
Total	$ 29,416	$ 2,167	$ (2,608)	$ 935	$ 29,910

We also have legally required asset retirement obligations related to certain assets within our electric and gas utility transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not possible to estimate a time period when these obligations could be settled and therefore, a value for the cost of these obligations cannot be measured at this time.

10 COMMON STOCK

PRIVATE PLACEMENT OF COMMON STOCK

On February 22, 2007, we completed the issuance and sale of approximately 4.17 million shares of common stock at a price of $36.00 per share in a private placement offering. We used approximately $145.6 million of net proceeds from this offering for debt reduction. On March 31, 2007, the shares were registered for resale under the Securities Act of 1933. At December 31, 2008, the shares are freely tradable by non-affiliates of the Company.

ISSUANCE OF UNREGISTERED SECURITIES

On March 21, 2008 and December 19, 2008, the Company issued 451,465 common shares and 142,339 common shares, respectively as additional consideration associated with the Earn-out Litigation described in Note 18. No additional consideration was received in exchange for the earn-out shares.

EQUITY COMPENSATION PLANS

We have several employee equity compensation plans, which allow for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 878,214 shares available to grant at December 31, 2008.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of SFAS 123(R) and is recognized over the vesting periods of the individual plans. Total stock-based compensation expense for the years ended December 31, 2008, 2007 and 2006 was $1.3 million ($0.9 million, after-tax), $5.8 million ($3.8 million, after-tax) and $2.6 million ($1.7 million, after-tax) respectively, and is included in Administrative and general expense on the accompanying Consolidated Statements of Income. As of December 31, 2008, total unrecognized compensation expense related to stock options and other non-vested stock awards is $5.0 million and is expected to be recognized over a weighted-average period of 2.2 years.

Stock Options

We have granted options with an option exercise price equal to the fair market value of the stock on the day of the grant. The options granted vest one-third each year for three years and expire ten years after the grant date.

A summary of the status of the stock option plans at December 31, 2008 is as follows:

	Shares (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Balance at January 1, 2008	539	$ 29.49		
Granted	—	—		
Forfeited/cancelled	(14)	41.67		
Expired	—	—		
Exercised	(90)	25.12		
Balance at December 31, 2008	435	$ 30.01	3.3	$ (1,327)
Exercisable at December 31, 2008	430	$ 29.97	3.2	$ (1,296)

The weighted-average grant-date fair value of options granted during the year ended December 31, 2006 was $3.79. No options were granted for the years ended 2008 and 2007. The total intrinsic value of options (the amount by which the market price of the stock on the date of exercise exceeded the exercise price of the option) exercised during the years ended December 31, 2008, 2007 and 2006 was $1.2 million, $1.9 million and $0.8 million, respectively. The total fair value of shares vested during the years ended December 31, 2008, 2007 and 2006 was less than $0.1 million, $0.4 million and $0.6 million, respectively.

The fair value of share-based awards is estimated on the date of grant using the Black-Scholes option pricing model. The fair value is affected by our stock price as well as a number of assumptions. The assumptions used to estimate the fair value of share-based awards are as follows:

Valuations Assumptions[1]	2006
Weighted average risk-free interest rate[2]	4.94%
Weighted average expected price volatility[3]	21.54%
Weighted average expected dividend yield[4]	3.98%
Expected life in years[5]	7

[1] Forfeitures are estimated using historical experience and employee turnover.
[2] Based on treasury interest rates with terms consistent with the expected life of the options.
[3] Based on a blended historical and implied volatility of our stock price in 2006.
[4] Based on our historical dividend payout and expectation of future dividend payouts and may be subject to substantial change in the future.
[5] Based upon historical experience.

Net cash received from the exercise of options for the years ended December 31, 2008, 2007 and 2006 was $2.0 million, $4.7 million and $3.7 million, respectively. The tax benefit realized from the exercise of shares granted for the years ended December 31, 2008, 2007 and 2006 was $0.4 million, $0.7 million and $0.3 million, respectively, and was recorded as an increase to equity.

As of December 31, 2008, there was less than $0.1 million of unrecognized compensation expense related to stock options that is expected to be recognized over a weighted-average period of less than one year.

Restricted Stock and Restricted Stock Units

The fair value of restricted stock and restricted stock unit awards equals the market price of our stock on the date of grant.

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest one-third per year over three years, contingent on continued employment. Compensation cost related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock and non-vested restricted stock units at December 31, 2008 is as follows:

	Stock And Stock Units (in thousands)	Weighted Average Grant Date Fair Value
Balance at January 1, 2008	115	$ 36.58
Granted	127	32.39
Vested	(55)	35.43
Forfeited	(15)	38.42
Balance at December 31, 2008	172	$ 33.69

The weighted-average grant-date fair value of restricted stock and restricted stock units granted and the total fair value of shares vested during the years ended December 31, 2008, 2007 and 2006 was as follows:

	Weighted Average Grant Date Fair Value	Total Fair Value of Shares Vested (in thousands)
2008	$ 32.39	$ 2,061
2007	$ 38.67	$ 1,975
2006	$ 35.57	$ 1,332

As of December 31, 2008, there was $4.1 million of unrecognized compensation expense related to non-vested restricted stock and non-vested restricted stock units that is expected to be recognized over a weighted-average period of 2.3 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based plan. Performance shares are awarded based on the Company's total shareholder return over designated performance periods as measured against a selected peer group. In addition, our stock price must also increase during the performance periods.

Participants may earn additional performance shares if the Company's total shareholder return exceeds the 50th percentile of the selected peer group. The final value of the performance shares may vary according to the number of shares of common stock that are ultimately granted based upon the performance criteria.

Outstanding Performance Periods at December 31, 2008 are as follows:

Grant Date	Performance Period	Target Grant of Shares (in thousands)
January 1, 2006	January 1, 2006 – December 31, 2008	26
January 1, 2007	January 1, 2007 – December 31, 2009	29
January 1, 2008	January 1, 2008 – December 31, 2010	28

The performance awards are paid 50% in cash and 50% in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100% in cash. If it is ever determined that a change-in-control is probable, the equity portion of $1.0 million at December 31, 2008 will be reclassified as a liability.

A summary of the status of the Performance Share Plan at December 31, 2008 and changes during the twelve-month period ended December 31, 2008, is as follows:

	Equity Portion		Liability Portion	
	Shares (in thousands)	Weighted-Average Grant Date Fair Value	Shares (in thousands)	Weighted-Average December 31, 2008 Fair Value
Balance at January 1, 2008	52	$ 33.43	52	
Granted	16	46.00	16	
Forfeited	(8)	36.20	(8)	
Vested	(18)	33.94	(18)	
Balance at December 31, 2008	42	$ 37.51	42	$ 14.81

The grant date fair value for the performance shares granted in 2008, 2007 and 2006 were determined by Monte Carlo simulation using a blended volatility of 23%, 20% and 21%, respectively, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date. The weighted-average grant-date fair value of performance share awards granted in the years ended December 31, 2008, 2007 and 2006 was as follows:

	Weighted Average Grant Date Fair Value
2008	$ 46.00
2007	$ 34.17
2006	$ 32.06

Performance plan payouts have been as follows:

Performance Period	Year of Payment	Stock Issued	Cash Paid	Total Intrinsic Value
			(in thousands)	
January 1, 2005 to December 31, 2007	2008	35	$ 1,526	$ 3,051
March 1, 2004 to December 31, 2006	2007	4	$ 160	$ 320
March 1, 2004 to December 31, 2005	2006	12	$ 419	$ 837

On January 29, 2009, the Compensation Committee of our Board of Directors determined that the plan criteria for the January 1, 2006 to December 31, 2008 performance period was not met. As a result, there will be no payout for this performance period.

As of December 31, 2008, there was $0.9 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.7 years.

OTHER PLANS

We have a Dividend Reinvestment and Stock Purchase Plan under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We have been funding the Plan by the purchase of shares of common stock on the open market since June 2004. At December 31, 2008, 443,976 shares of unissued common stock were available for future offering under the Plan.

We issued 32,568 shares of common stock with an intrinsic value of $1.2 million in the twelve months ended December 31, 2008 to certain key employees under the Short-term Annual Incentive Plan, a performance-based plan. The payout was fully accrued at December 31, 2007. We issued 33,143 and 25,685 shares of common stock in 2007 and 2006, respectively, under the Short-term Annual Incentive Plan.

In addition, we will issue common stock with an intrinsic value of approximately $0.7 million in 2009 for the 2008 Short-term Annual Incentive Plan.

DIVIDEND RESTRICTIONS

Our revolving credit facility and Acquisition Facility contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenants include the following: interest expense coverage ratio of not less than 2.5 to 1.0; a recourse leverage ratio not to exceed 0.70 to 1.00 (or 0.65 to 1.00 after the first year of the Aquila acquisition); and a minimum consolidated net worth of $625 million plus 50% of aggregate consolidated net income since January 1, 2005. As of December 31, 2008, we were in compliance with the above covenants.

TREASURY SHARES

We acquired 15,107 shares, 767 shares and 6,224 shares of treasury stock related to forfeitures of unvested restricted stock in 2008, 2007 and 2006, respectively, and 17,233 shares, 16,418 shares and 8,095 shares related to the share withholding for the payment of taxes associated with the vesting of restricted shares and stock option exercise stock swaps in 2008, 2007 and 2006, respectively.

We utilized 38,073 shares, 8,030 shares and 46,785 shares of treasury stock in 2008, 2007 and 2006, respectively, related to grants from the different equity plans.

11 FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments at December 31 are as follows (in thousands):

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 168,491	$ 168,491	$ 76,889	$ 76,889
Restricted cash	$ —	$ —	$ 5,443	$ 5,443
Derivative financial instruments – assets	$ 82,867	$ 82,867	$ 38,413	$ 38,413
Derivative financial instruments – liabilities	$ 140,682	$ 140,682	$ 48,755	$ 48,755
Notes payable	$ 703,800	$ 703,800	$ 37,000	$ 37,000
Long-term debt, including current maturities	$ 503,330	$ 456,322	$ 633,627	$ 648,611

The following methods and assumptions were used to estimate the fair value of each class of our financial instruments.

CASH AND CASH EQUIVALENTS AND RESTRICTED CASH

The carrying amount approximates fair value due to the short maturity of these instruments.

DERIVATIVE FINANCIAL INSTRUMENTS

These instruments are carried at fair value. Descriptions of the various instruments we use and the valuation method employed are included in Note 2.

NOTES PAYABLE

The carrying amount approximates fair value due to their variable interest rates with short reset periods.

LONG-TERM DEBT

The fair value of our long-term debt is estimated based on quoted market rates for debt instruments having similar maturities and similar debt ratings. The first mortgage bonds issued by Black Hills Power and Cheyenne Light are either currently not callable or are subject to make-whole provisions which would eliminate any economic benefits for us to call the bonds.

12 IMPAIRMENT OF LONG LIVED ASSETS, GOODWILL AND CAPITALIZED DEVELOPMENT COSTS

As a result of low crude oil and natural gas prices at the end of 2008, we recorded a non-cash ceiling test impairment of oil and gas assets included in the Oil and Gas segment. The lower oil and gas prices at December 31, 2008 resulted in a $91.8 million pre-tax decrease in the full cost accounting method's ceiling limit for capitalized oil and gas property costs. The write-down in the net carrying value of our natural gas and crude oil property was recorded as impairment expense and was based on the December 31, 2008 NYMEX price of $5.71 per Mcf, adjusted to $4.44 per Mcf at the wellhead, for natural gas; and $44.60 per barrel, adjusted to $32.74 per barrel at the wellhead, for crude oil.

In December 2007, the Rupert and Glenns Ferry partnerships, in which we have 50% ownership interests, impaired the carrying amounts of their property, plant and equipment to reflect the partnerships' assessment of the recoverability of their respective carrying amounts. We account for these investments using the equity method of accounting. Accordingly, our carrying amount for these investments was reduced by $3.9 million to reflect the increased losses from the partnerships' impairment charges. In addition, we wrote off $0.6 million of net goodwill impairment directly related to our investments in the partnerships. At December 31, 2007, our remaining carrying amount for these partnership investments was nominal. Our investment in the Rupert and Glenns Ferry partnership is included in the Power Generation segment.

During September 2007, we assessed the recoverability of the carrying value of the Ontario power plant due to the pending thermal host contract expiration without a long-term extension. The carrying amount of the assets tested for impairment was $1.3 million. The assessment resulted in an impairment charge of $1.3 million, primarily for net property, plant and equipment and intangible assets. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by future discounted cash flow estimates. In addition, $1.4 million has been accrued for a contract termination payment and other related costs. These charges are included as a component of Operating expenses on the accompanying Consolidated Statements of Income. Operating results from the Ontario plant are included in the Power Generation segment.

13 OPERATING LEASES

We have entered into lease agreements relating to a compressor lease, vehicle leases and office facility leases. Rental expense incurred under these operating leases was $3.5 million, $0.8 million and $0.8 million for the years ended December 31, 2008, 2007 and 2006, respectively.

The following is a schedule of future minimum payments required under the operating lease agreements (in thousands):

2009	$ 3,703
2010	1,992
2011	1,113
2012	1,002
2013	778
Thereafter	1,726
	$ 10,314

14 INCOME TAXES

Income tax expense (benefit) from continuing operations for the years indicated was:

	2008	2007	2006
		(in thousands)	
Current:			
Federal	$ (215,957)	$ 22,605	$ 1,573
State	(1,330)	246	(438)
Foreign[(1)]	1,179	2,114	893
	(216,108)	24,965	2,028
Deferred:			
Federal	185,614	7,405	20,748
State	1,414	349	621
Tax credit amortization	(315)	(292)	(294)
	186,713	7,462	21,075
	$ (29,395)	$ 32,427	$ 23,103

[(1)] Foreign taxes represent income taxes incurred through our Canadian activities.

The above 2008 amounts reflect the income tax impacts associated with our like-kind exchange tax planning structure. The tax planning structure allowed us to defer approximately $185 million of income taxes related to the IPP Transaction which would have been payable for the 2008 tax year without such a structure.

The temporary differences, which gave rise to the net deferred tax liability, were as follows:

Years ended December 31,	2008	2007
	(in thousands)	
Deferred tax assets, current:		
Asset valuation reserves	$ 2,366	$ 1,609
Mining development and oil exploration	896	373
Unbilled revenue	581	1,480
Deferred costs	–	962
Employee benefits	5,839	3,470
Items of other comprehensive income	1,717	6,606
Derivative fair value adjustments	33,054	250
Other	142	97
	44,595	14,847
Deferred tax liabilities, current:		
Prepaid expenses	2,139	1,890
Derivative fair value adjustments	12,252	1,649
Items of other comprehensive income	6,566	1,601
Deferred costs	10,369	–
Other	3,025	5,195
	34,351	10,335
Net deferred tax asset, current	$ 10,244	$ 4,512
Deferred tax assets, non-current:		
Employee benefits	$ 17,838	$ 14,991
Regulatory liabilities	28,381	5,487
Deferred revenue	591	467
Deferred costs	79	395
State net operating loss	342	1,272
Items of other comprehensive income	15,872	6,400
Foreign tax credit carryover	3,591	3,304
Net operating loss (net of valuation allowance)	7,816	7,846
Asset impairment	32,607	58,819
Derivative fair value adjustment	–	203
Other	8,794	5,703
	115,911	104,887
Deferred tax liabilities, non-current:		
Accelerated depreciation, amortization and other plant-related differences	200,119	210,447
Regulatory assets	36,088	13,589
Mining development and oil exploration	94,994	84,771
Deferred costs	352	3,669
Derivative fair value adjustments	221	146
Items of other comprehensive income	4,139	–
Other	3,605	–
	339,518	312,622
Net deferred tax liability, non-current	$ 223,607	$ 207,735
Net deferred tax liability	$ 213,363	$ 203,223

The following table reconciles the change in the net deferred income tax liability from December 31, 2007 to December 31, 2008 to deferred income tax expense:

	2008 (in thousands)
Net change in deferred income tax liability from the preceding table	$ 10,140
Deferred taxes associated with other comprehensive income	(1,773)
Deferred taxes related to net operating loss from acquisitions	2,071
Deferred taxes related to regulatory assets and liabilities	(1,333)
Deferred taxes related to acquisition	13,422
Deferred taxes associated with IPP Transaction	48,131
Deferred taxes associated with property basis differences	114,170
Other	1,885
Deferred income tax expense for the period	$ 186,713

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2008	2007	2006
Federal statutory rate	(35.0)%	35.0%	35.0%
State income tax	–	0.4	0.2
Amortization of excess deferred and investment tax credits	(0.4)	(0.4)	(0.7)
Percentage depletion in excess of cost	–	(1.3)	(1.6)
Equity AFUDC	(1.4)	(1.6)	(1.2)
IRS exam tax adjustment*	–	–	(1.8)
State exam tax adjustment**	–	(0.6)	–
Tax credits	–	(0.3)	–
Other	0.8	(1.1)	(0.4)
	(36.0)%	30.1%	29.5%

* As a result of IRS exam settlements for the 2001-2003 tax years, a reduction to income tax expense of approximately $1.4 million was recorded during 2006.

** As a result of state tax exam settlements for the 2001-2003 tax years, a tax benefit of approximately $0.7 million (net of the federal tax effect) was recorded in 2007.

At December 31, 2008, we had the following remaining Net Operating Loss (NOL) carryforwards which were acquired as part of our 2003 acquisition of Mallon Resources Corporation (Mallon):

Net Operating Loss Carryforward (in thousands)	Expiration Year
$ 3,312	2021
17,146	2022
3,104	2023

As of December 31, 2008, we had a valuation allowance of $1.2 million against these NOL carryforwards. Ultimate usage of these NOL's depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOL's, the offsetting amount would affect our financial reporting basis in the acquired Mallon properties.

FIN 48

We adopted the provisions of FIN 48 on January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS 109 and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken. As a result of the implementation of FIN 48, we recognized an approximate $0.7 million benefit from a decrease in the liability for unrecognized tax benefits. This benefit was accounted for as an adjustment to the January 1, 2007 balance of retained earnings.

The following table reconciles the total amounts of unrecognized tax benefits at the beginning and end of the period:

	2008	2007
	(in thousands)	
Beginning balance at December 31	$ 75,770	$ 72,583
Additions for prior year tax positions	5,015	4,719
Reductions for prior year tax positions	(72,948)	(46)
Additions for current year tax positions	112,185	623
Settlements	–	(2,109)
Ending balance at December 31	$ 120,022	$ 75,770

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $4.0 million.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in income tax expense. During the years ended December 31, 2008, 2007 and 2006, we recognized approximately $0.5 million, $0.1 million and $0.4 million, respectively of interest. We had approximately $0.4 million and $1.3 million accrued for interest at December 31, 2008 and 2007, respectively.

We file income tax returns with the IRS, various state jurisdictions and Canada. We are currently under examination by the IRS for the 2004, 2005 and 2006 tax years. We remain subject to examination by Canadian income tax authorities for tax years as early as 1999.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statute of limitations prior to December 31, 2009.

In 2005, Canadian income tax returns were filed for the years of 1999 – 2003. Excess foreign tax credits were generated and are available to offset United States federal income taxes. At December 31, 2008, we had the following remaining foreign tax credit carryforwards (in thousands):

Foreign Tax Credit Carryforward	Expiration Year
$ 269	2012
11	2013
376	2014
694	2015
940	2016
1,301	2017

15 COMPREHENSIVE INCOME

The following table displays the related tax effects allocated to each component of Other Comprehensive Income (Loss) for the years ended December 31 (in thousands):

	2008		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ (12,343)	$ 4,331	$ (8,012)
Fair value adjustment of derivatives designated as cash flow hedges	(15,353)	5,224	(10,129)
Reclassification adjustments of cash flow hedges dedesignated and included in net income	42,710	(14,949)	27,761
Reclassification adjustments of cash flow hedges settled and included in net income	(5,992)	2,097	(3,895)
Comprehensive income (loss)	$ 9,022	$ (3,297)	$ 5,725

	2007		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ 3,513	$ (1,224)	$ 2,289
Fair value adjustment of derivatives designated as cash flow hedges	(58,603)	20,212	(38,391)
Reclassification adjustments of cash flow hedges settled and included in net income	14,228	(4,910)	9,318
Reclassification adjustments for cash flow hedges settled and included in regulatory assets	4,288	(1,497)	2,791
Comprehensive income (loss)	$ (36,574)	$ 12,581	$ (23,993)

	2006		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ 994	$ (348)	$ 646
Fair value adjustment of derivatives designated as cash flow hedges	28,640	(10,419)	18,221
Reclassification adjustments of cash flow hedges settled and included in net income	(5,289)	1,851	(3,438)
Comprehensive income	$ 24,345	$ (8,916)	$ 15,429

Balances by classification included within Accumulated other comprehensive (loss) income on the accompanying Consolidated Balance Sheets are as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Amount from Equity-method Investees	Total
As of December 31, 2008	$ (4,522)	$ (14,127)	$ (134)	$ (18,783)
As of December 31, 2007	$ (18,178)	$ (6,115)	$ (215)	$ (24,508)

16 DISCONTINUED OPERATIONS

We account for discontinued operations under the provisions of SFAS 144. Accordingly, results of operations and the related charges for discontinued operations have been classified as Income (loss) from discontinued operations, net of income taxes in the accompanying Consolidated Statements of Income. Assets and liabilities of the discontinued operations have been reclassified and reflected on the accompanying Consolidated Balance Sheets as Assets of discontinued operations and Liabilities of discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the reclassifications on a consistent basis.

IPP TRANSACTION

On April 29, 2008, we entered into a definitive agreement to sell seven IPP plants to affiliates of Hastings and IIF for $840 million, subject to certain working capital adjustments. The transaction was completed July 11, 2008. Under the agreement, we received net pre-tax cash proceeds of $756 million, including the effects of estimated working capital adjustments and other costs and our required payoff of approximately $67.5 million of associated project level debt. The after-tax gain recorded on the asset sale was approximately $139.7 million. For business segment reporting purposes, results were previously included in the Power Generation segment.

Revenues and net income from the discontinued operations associated with the divested IPP plants at December 31 were as follows (in thousands):

	2008	2007	2006
Operating revenues	$ 59,572	$ 121,076	$ 114,297
Pre-tax income from discontinued operations	27,140	38,057	29,483
Gain on sale	233,599	–	–
Income tax expense	(103,758)	(13,214)	(10,699)
Net income from discontinued operations	$ 156,981	$ 24,843	$ 18,784

Allocation of corporate expenses to discontinued operations was made in accordance with SFAS 144 and EITF 87-24. The indirect corporate costs and inter-segment interest expense related to the IPP assets sold and not reclassified to discontinued operations were $11.8 million, $19.0 million and $19.7 million for the years ended 2008, 2007 and 2006, respectively. These allocated costs remain in the Power Generation segment.

Interest expenses included within the operations of the discontinued entities were recorded pursuant to EITF 87-24 and included interest expense on debt which was required to be repaid as a result of the sale transaction. In accordance with EITF 87-24, interest expense was allocated to discontinued operations based on the ratio of the assets sold to total Company net assets, excluding the known debt repayment. For the years ended December 31, 2008, 2007 and 2006, interest expense allocated to discontinued operations was $4.7 million, $11.3 million and $13.6 million, respectively.

Net assets associated with the divested IPP plants were as follows (in thousands):

	December 31, 2007
Current assets	$ 34,112
Property, plant and equipment, net of accumulated depreciation	485,286
Goodwill	18,095
Intangible assets (net of accumulated amortization of $27,363)	21,023
Other non-current assets	13,163
Current liabilities	(15,615)
Long-tem debt	(73,928)
Other non-current liabilities	(139)
Net assets	$ 481,997

SALE OF CRUDE OIL MARKETING AND TRANSPORTATION ASSETS

On January 5, 2006, we entered into an agreement to sell the crude oil marketing and transportation operating assets of BHER. The sale was completed on March 1, 2006. We received approximately $41.0 million of cash proceeds, which was used for debt reduction or other corporate purposes. For business segment reporting purposes, BHER's results were previously included in the Energy Marketing segment.

Revenues, net income (loss) from discontinued operations and net assets (liabilities) of the crude oil marketing and transportation business at December 31 were as follows (in thousands):

	2006
Operating revenues	$ 171,911
Pre-tax loss from discontinued operations	$ (3,018)
Pre-tax gain on sale of assets	13,659
Income tax expense	(3,832)
Net income from discontinued operations	$ 6,809

Net assets and financial results for the crude oil marketing and transportation discontinued operations were not significant as of and for the years ended December 31, 2008 and 2007.

17 EMPLOYEE BENEFIT PLANS

DEFINED CONTRIBUTION PLANS

We sponsor three 401(k) savings plans. Eligible employees of the Company and its subsidiaries (other than Cheyenne Light and Black Hills Energy) may participate in the Black Hills Corporation Plan. The Cheyenne Light Plan covers eligible employees of Cheyenne Light and the Black Hills Energy Plan covers eligible employees of our utility subsidiaries doing business as Black Hills Energy.

Participants in the Black Hills Corporation Plan may elect to invest up to 100% of their eligible compensation on a pre-tax basis to the Plan up to the maximum amounts established by the IRS. The Black Hills Corporation Plan provides a matching contribution of 100% of the employee's annual tax-deferred contribution up to a maximum of 3% of eligible compensation. Matching contributions vest at 20% per year and are fully vested when the participant has five years of service with the Company.

Participants in the Cheyenne Light Plan may elect to invest up to 100% of their eligible compensation on a pre-tax or after-tax basis up to maximum amounts established by the IRS. The Cheyenne Light Plan provides for two matching formulas depending on an employee's status as a bargaining unit employee or as a non-bargaining unit employee. Bargaining unit employees receive a maximum match of 5% of eligible compensation based upon the following formula: 100% of the employee's tax-deferred contribution on the first 3% of eligible compensation, plus 50% of the next 4% of eligible compensation. Non-bargaining unit employees receive a maximum match of 4% of eligible compensation based upon the following formula: 100% of the employee's tax-deferred contribution on the first 3% of eligible compensation, plus 50% of the next 2% of eligible compensation. Matching contributions under both formulas vest immediately. In addition, the Cheyenne Light Plan provides for a profit sharing contribution for certain eligible Cheyenne Light employees equal to 3.5% to 10% of eligible compensation, depending on age and years of service. Profit sharing contributions vest at 20% per year and are fully vested after completion of five years of service.

Participants in the Black Hills Energy Plan, which was established in connection with the Aquila Transaction, may elect to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis up to the maximum amounts established by the IRS. The Black Hills Energy Plan provides a matching contribution of 100% of the employee's annual contribution up to a maximum of 6% of eligible compensation. Matching contributions vest at 20% per year and are fully vested when the participant has five years of service with the Company.

The Black Hills Corporation Plan matching contributions were $2.1 million for 2008, $1.7 million for 2007 and $1.5 million for 2006. The Cheyenne Light Retirement Savings Plan matching contributions were $0.3 million for 2008, $0.3 million for 2007 and $0.2 million for the initial plan year of 2006. The Cheyenne Light Plan profit sharing contributions were $0.1 million for 2008, $0.1 million for 2007 and $0.1 million for 2006. The Black Hills Energy Plan matching contributions were $1.4 million for 2008.

SFAS 158

The application of SFAS 158 requires recognition of the funded status of postretirement benefit plans in the statement of financial position. The funded status for pension plans is measured as the difference between the projected benefit obligation and the fair value of plan assets. The funded status for all other benefit plans is measured as the difference between the accumulated benefit obligation and the fair value of plan assets. A liability is recorded for an amount by which the benefit obligation exceeds the fair value of plan assets or an asset is recorded for any amount by which the fair value of plan assets exceeds the benefit obligation.

Prior to the December 31, 2006 effective date of SFAS 158, liabilities recorded for postretirement benefit plans were reduced by any unrecognized net periodic benefit cost. Upon adoption of SFAS 158, the unrecognized net periodic benefit cost, previously recorded as an offset to the liability for benefit obligations, was reclassified within accumulated other comprehensive income (loss), net of tax. For our regulated utilities, we applied the guidance under SFAS 71, and accordingly, the unrecognized net periodic benefit cost that would have been reclassified to Accumulated other comprehensive income was alternatively recorded as a regulatory asset or regulatory liability, net of tax.

SFAS 158 required that the measurement date of plans be the date of our year-end balance sheet. We previously used a September 30 measurement date and during 2008, changed the measurement date to December 31, which resulted in a $1.4 million after-tax adjustment to retained earnings being recognized. The amortization of prior service costs for October 1, 2007 to December 31, 2007 was less than $0.1 million, after-tax, and the service cost, interest cost and expected return on plan assets for October 1, 2007 to December 31, 2007 was $1.3 million, after-tax.

DEFINED BENEFIT PENSION PLAN

We have three non-contributory defined benefit pension plans (the Pension Plans). The Black Hills Corporation Pension Plan covers eligible employees of Black Hills Corporation, Black Hills Service Company, Black Hills Power, WRDC and BHEP. Benefits are based on years of service and compensation levels during the highest five consecutive years of the last ten years of service. The Cheyenne Light Pension Plan covers eligible employees of Cheyenne Light. Benefits for the bargaining unit employees of Cheyenne Light are based on years of service and compensation levels during the highest three consecutive 12-month periods of service, reduced by the vested benefits under the predecessor plans, if any. Benefits for the non-bargaining unit employees of Cheyenne Light are based on annual credits for each year of service plus investment credits. The Black Hills Energy Pension Plan covers eligible employees of our utility subsidiaries doing business as Black Hills Energy. Benefits are based on years of service and compensation levels during the highest four consecutive years of the last ten years of service.

Our funding policy is in accordance with the federal government's funding requirements. The Pension Plans' assets are held in trust and consist primarily of equity and fixed income investments. We use a December 31 measurement date for the Pension Plans.

The Pension Plans' expected long-term rate of return on assets assumption is based upon the weighted average expected long-term rate of returns for each individual asset class. The asset class weighting is determined using the target allocation for each asset class in the Plan portfolio. The expected long-term rate of return for each asset class is determined primarily from long-term historical returns for the asset class, with adjustments if it is anticipated that long-term future returns will not achieve historical results.

The expected long-term rate of return for equity investments was 9.5% for the 2008 and 2007 plan years. For determining the expected long-term rate of return for equity assets, we reviewed annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2008, 8.4%, 11.0%, 9.0% and 9.2%, respectively. Fund management fees were estimated to be 0.18% for S&P 500 Index assets and 0.45% for other assets. The expected long-term rate of return on fixed income investments was 6.0%; the return was based upon historical returns on 10-year treasury bonds of 7.1% from 1962 to 2007, and adjusted for recent declines in interest rates. The expected long-term rate of return on cash investments was estimated to be 4.0%; expected cash returns were estimated to be 2.0% below long-term returns on intermediate-term bonds.

Plan Assets

The percentage of total plan asset fair value by investment category for our Pension Plans at December 31 were as follows:

	2008	2007
Equity	60%	77%
Real estate	5	–
Fixed income	33	21
Cash	2	2
Total	100%	100%

As a result of the severe decline in equity values in the fourth quarter of 2008 and in light of the improved relative value of fixed income investment opportunities, we are undergoing a review to consider a revision of the pension plan investment allocations.

The revision is expected to result in a higher fixed income allocation. Until the investment allocation review is completed and implemented, we have suspended our practice of rebalancing the portfolio on a quarterly basis. This has resulted in an investment allocation of 60% equities, 35% fixed income/cash and 5% real estate at December 31, 2008.

The Black Hills Energy Pension Plan's investment policy includes the investment objective that the achieved long-term rate of return meets or exceeds the assumed actuarial rate. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity and fixed income assets. The policy provides that the Pension Plans will maintain a passive core United States Stock portfolio based on a broad market index. Complementing this core will be investments in United States and foreign equities and fixed income through actively managed mutual funds.

The policy contains certain prohibitions on transactions in separately managed portfolios in which the Pension Plans may invest, including prohibitions on short sales and the use of options or futures contracts. With regard to pooled funds, the policy requires the evaluation of the appropriateness of such funds for managing Pension Plan assets if a fund engages in such transactions. The Pension Plans have historically not invested in funds engaging in such transactions.

Cash Flows

We made no contributions to the Black Hills Corporation Pension Plan in 2008, but expect to contribute $4.0 million to the Plan in fiscal year 2009. We made a $0.5 million contribution to the Cheyenne Light Pension Plan in the first quarter of 2008 and expect to make a $1.5 million contribution during fiscal year 2009. We expect to make a $13.0 million contribution to the Black Hills Energy Plan in fiscal year 2009.

SUPPLEMENTAL NONQUALIFIED DEFINED BENEFIT RETIREMENT PLANS

We have various supplemental retirement plans for key executives of the Company. The plans are nonqualified defined benefit plans. We use a December 31 measurement date for the plans.

Plan Assets

The plans have no assets. We fund on a cash basis as benefits are paid.

Estimated Cash Flows

The estimated employer contribution is expected to be $0.9 million in 2009. Contributions are expected to be made in the form of benefit payments.

NON-PENSION DEFINED BENEFIT POSTRETIREMENT PLAN

We sponsor three retiree healthcare plans (the Plans): the Black Hills Corporation Postretirement Healthcare Plan, the Healthcare Plan for Retirees of Cheyenne Light, Fuel and Power Company, and the Black Hills Energy Postretirement Healthcare Plan. Employees who participate in the Black Hills Corporation Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service with the Company are entitled to postretirement healthcare benefits. Employees who participate in the Healthcare Plan for Retirees of Cheyenne Light, Fuel and Power Company and who retire from Cheyenne Light on or after attaining age 55 and after completion of a number of consecutive years of service, which when added to the employee's age totals 90, are entitled to postretirement healthcare benefits. Employees who are participants in the Black Hills Energy Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service with the Company are entitled to postretirement healthcare benefits.

The benefits for all plans are subject to premiums, deductibles, co-payment provisions and other limitations. We may amend or change the plans periodically. We are not pre-funding the Black Hills Corporation or Cheyenne Light retiree healthcare plans. A portion of Black Hills Energy's Postretirement Healthcare Plan is pre-funded via Voluntary Employees' Beneficiary Association (VEBA), and the assets are held in trust. We use a December 31 measurement date for the Plans.

It has been determined that the post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy. The effect of the Medicare Part D subsidy on the accumulated postretirement benefit obligation for the 2008 fiscal year was an actuarial gain of approximately $5.7 million. The effect on 2009 net periodic postretirement benefit cost was a decrease of approximately $0.3 million.

Plan Assets
The Black Hills Corporation and Cheyenne Light retiree healthcare plans have no assets. We fund on a cash basis as benefits are paid. The Black Hills Energy Plan provides for partial pre-funding via VEBA. The assets related to this pre-funding are held in trust and are for the benefit of the union and non-union employees of Black Hills Energy located in the states of Kansas and Iowa. We do not pre-fund the Postretirement Healthcare Plan for those employees outside Kansas and Iowa.

Estimated Cash Flows
The estimated employer contribution is expected to be $2.8 million in 2009. Contributions are expected to be made in the form of benefit payments.

The following tables provide a reconciliation of the employee benefit plan obligations and fair value of assets for 2008 and 2007, components of the net periodic expense for the years ended 2008, 2007 and 2006 and elements of accumulated other comprehensive income for 2008 and 2007.

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
			(in thousands)			
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 78,983	$ 77,471	$ 19,943	$ 19,843	$ 13,726	$ 14,042
Sponsorship transfer[(a)]	132,236	–	1,530	–	20,904	–
Service cost	5,474	2,745	559	410	847	539
Interest cost	10,360	4,517	1,588	1,157	1,705	828
Actuarial (gain) loss	21,452	(3,040)	1,123	(737)	1,710	(1,445)
Amendments	20	–	–	–	(768)	–
Benefits paid	(5,980)	(2,710)	(1,881)	(730)	(2,369)	(817)
Medicare Part D accrued	–	–	–	–	81	85
Plan participant's contributions	–	–	–	–	1,104	494
Net increase (decrease)	163,562	1,512	2,919	100	23,214	(316)
Projected benefit obligation at end of year	$ 242,545	$ 78,983	$ 22,862	$ 19,943	$ 36,940	$ 13,726

[(a)] The sponsorship transfer presents the amount recorded from the change in sponsorship from Aquila to the Company from the Aquila Transaction.

A reconciliation of the fair value of Plan assets (as of the December 31 measurement date) is as follows:

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
			(in thousands)			
Beginning market value of plan assets	$ 75,107	$ 65,990	$ –	$ –	$ –	$ –
Acquisition transfer	112,672	–	–	–	4,525	–
Investment income	(45,400)	11,318	–	–	357	–
Contributions	500	510	–	–	1,234	–
Benefits paid	(5,980)	(2,711)	–	–	(1,166)	–
Ending market value of plan assets	$ 136,899	$ 75,107	$ –	$ –	$ 4,950	$ –

Amounts recognized in the statement of financial position consist of:

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
			(in thousands)			
Regulatory asset	$ 70,277	$ 2,998	$ –	$ –	$ 210	$ –
Current liability	$ –	$ –	$ 789	$ 765	$ 1,948	$ 286
Non-current asset	$ –	$ 3,529	$ –	$ –	$ –	$ –
Non-current liability	$ 105,646	$ 7,404	$ 22,073	$ 18,992	$ 30,041	$ 13,386
Regulatory liability	$ –	$ 56	$ –	$ –	$ 1,513	$ 1,682

Accumulated Benefit Obligation

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
			(in thousands)			
Accumulated benefit obligation – Black Hills Corporation	$ 68,781	$ 61,513	$ 21,964	$ 14,577	$ 11,547	$ 9,847
Accumulated benefit obligation – Black Hills Energy	$ 131,936	$ –	$ 609	$ –	$ 21,478	$ –
Accumulated benefit obligation – Cheyenne Light	$ 3,212	$ 2,344	$ –	$ –	$ 3,914	$ 3,879

Components of Net Periodic Expense

	Defined Benefit Pension Plans 2008	Defined Benefit Pension Plans 2007	Defined Benefit Pension Plans 2006	Supplemental Nonqualified Defined Benefit Retirement Plans 2008	Supplemental Nonqualified Defined Benefit Retirement Plans 2007	Supplemental Nonqualified Defined Benefit Retirement Plans 2006	Non-pension Defined Benefit Postretirement Plans 2008	Non-pension Defined Benefit Postretirement Plans 2007	Non-pension Defined Benefit Postretirement Plans 2006
				(in thousands)					
Service cost	$ 4,720	$ 2,745	$ 2,596	$ 447	$ 410	$ 349	$ 721	$ 539	$ 654
Interest cost	9,130	4,517	4,165	1,277	1,157	1,079	1,488	828	813
Expected return on assets	(10,627)	(5,493)	(4,988)	–	–	–	(97)	–	–
Amortization of prior service cost	163	153	153	10	13	13	–	–	(24)
Amortization of transition obligation	–	–	–	–	–	–	59	60	150
Recognized net actuarial loss	–	507	906	569	713	797	(81)	(16)	–
Net periodic expense	$ 3,386	$ 2,429	$ 2,832	$ 2,303	$ 2,293	$ 2,238	$ 2,090	$ 1,411	$ 1,593

Accumulated Other Comprehensive Income

In accordance with SFAS 158, amounts included in accumulated other comprehensive income (loss), after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31 are as follows:

	Defined Benefit Pension Plans 2008	Defined Benefit Pension Plans 2007	Supplemental Nonqualified Defined Benefit Retirement Plans 2008	Supplemental Nonqualified Defined Benefit Retirement Plans 2007	Non-pension Defined Benefit Postretirement Plans 2008	Non-pension Defined Benefit Postretirement Plans 2007
			(in thousands)			
Net (loss) gain	$ 18,176	$ (1,141)	$ (5,235)	$ (4,967)	$ 9	$ 230
Prior service cost	314	(192)	(3)	(11)	–	–
Transition obligation	–	–	–	–	(21)	(28)
	$ 18,490	$ (1,333)	$ (5,238)	$ (4,978)	$ (12)	$ 202

The amounts in accumulated other comprehensive income, regulatory assets or regulatory liabilities, after-tax, expected to be recognized as a component of net periodic benefit cost during calendar year 2009 are as follows:

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Plans
		(in thousands)	
Net loss (gain)	$ 1,954	$ 383	$ (21)
Prior service cost	107	–	(58)
Transition obligation	–	–	39
Total net periodic benefit cost expected to be recognized during calendar year 2008	$ 2,061	$ 383	$ (40)

Assumptions

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
Weighted-average assumptions used to determine benefit obligations:	2008	2007	2006	2008	2007	2006	2008	2007	2006
Discount rate	6.20%	6.35%	5.95%	6.20%	6.35%	5.95%	6.10%	6.35%	5.95%
Rate of increase in compensation levels	4.25%	4.34%	4.31%	5.00%	5.00%	5.00%	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2008	2007	2006	2008	2007	2006	2008	2007	2006
Discount rate:									
Black Hills Corporation	6.35%	5.95%	5.75%	6.35%	5.95%	5.75%	6.35%	5.95%	5.75%
Black Hills Energy	7.00%	N/A	N/A	5.00%	N/A	N/A	6.75%	N/A	N/A
Expected long-term rate of return on assets*	8.50%	8.50%	8.50%	N/A	N/A	N/A	5.00%	N/A	N/A
Rate of increase in compensation levels	4.34%	4.31%	4.34%	N/A	5.00%	5.00%	N/A	N/A	N/A

*The expected rate of return on plan assets remained at 8.5% for the calculation of the 2008 net periodic pension cost.

The healthcare trend rate assumption for 2008 fiscal year benefit obligation determination and 2009 fiscal year expense is a 9% increase for 2009 grading down 1% per year until a 5% ultimate trend rate is reached in fiscal year 2013. The healthcare cost trend rate assumption for the 2007 fiscal year benefit obligation determination and 2008 fiscal year expense was a 10% increase for 2008 grading down 1% per year until a 5% ultimate trend rate is reached in fiscal year 2013.

The healthcare cost trend rate assumption has a significant effect on the amounts reported. A 1% increase in the healthcare cost trend assumption would increase the service and interest cost $0.3 million or 14% and the accumulated periodic postretirement benefit obligation $3.4 million or 9%. A 1% decrease would reduce the service and interest cost by $0.3 million or 11% and the accumulated periodic postretirement benefit obligation $2.5 million or 7%.

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plan	Non-pension Defined Benefit Postretirement Plans		
			Expected Gross Benefit Payments	Expected Medicare Part D Drug Benefit Subsidy	Expected Net Benefit Payments
2009	$ 9,616	$ 956	$ 3,328	$ (516)	$ 2,812
2010	10,349	893	3,597	(576)	3,021
2011	11,087	917	3,702	(639)	3,063
2012	11,794	930	3,629	(706)	2,923
2013	12,760	951	3,540	(769)	2,771
2014-2018	80,444	6,872	15,015	(2,493)	12,522

18 COMMITMENTS AND CONTINGENCIES

VARIABLE INTEREST ENTITIES

In May 2003, our Black Hills Wyoming subsidiary entered into an agreement with Wygen Funding, Limited Partnership (the VIE) to lease the Wygen I plant. We were considered the "primary beneficiary" of this arrangement and, therefore, included the VIE in our consolidated financial statements. The initial term of the lease was five years and included a purchase option equal to the adjusted acquisition cost, which was essentially equal to the cost of the plant. We guaranteed the obligations of Black Hills Wyoming under the lease agreement.

At the end of the initial lease term in June 2008, we elected to purchase the Wygen I plant at an adjusted acquisition cost of $133.1 million. In conjunction with this purchase, we retired $128.3 million of Wygen I project debt through borrowings on our revolving credit facility, and extinguished the $111.0 million guarantee obligation under the Wygen I lease. Since the plant and its financial activities were previously consolidated into our financial statements, the transaction had minimal impact on our consolidated financial statements.

POWER PURCHASE AND TRANSMISSION SERVICES AGREEMENTS

In 1983, we entered into a 40 year power purchase agreement with PacifiCorp providing for our purchase of 75 MW of electric capacity and energy from PacifiCorp's system. An amended agreement signed in October 1997 reduced the contract capacity by 25 MW (5 MW per year starting in 2000) to the current 50 MW of capacity. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants. Costs incurred under this agreement were $11.6 million in 2008, $10.9 million in 2007 and $10.1 million in 2006.

We have a power purchase agreement with PSCo, expiring in 2011, for 280 MW of capacity and energy in 2009, increasing 10 MW per year to 300 MW in 2011. Pricing for the power purchase agreement is based on annual contracted capacity and an 85% load factor at current FERC approved rates.

We also have a firm point-to-point transmission service agreement with PacifiCorp that expires on December 31, 2023. The agreement provides that the following amounts of our capacity and energy will be transmitted by PacifiCorp: 17 MW in 2004-2006 and 50 MW in 2007-2023. Costs incurred under this agreement were $1.2 million in 2008, $1.2 million in 2007 and $0.4 million in 2006.

LONG-TERM POWER SALES AGREEMENTS

Through our subsidiaries, we have the following significant long-term power sales contracts with non-affiliated third-parties:

- We have a 10-year power sales contract with MEAN for 20 MW of unit-contingent capacity from the Neil Simpson II plant. The contract expires in 2013.
- During 2008, we had a power sales contract with MEAN for 20 MW of unit-contingent capacity from Wygen I. In January 2009, we completed the sale of a 23.5% ownership interest in Wygen I to MEAN. In conjunction with the sale, the 20 MW power purchase agreement was terminated (see Note 24).
- We have a power purchase agreement with MDU for the supply of up to 74 MW of capacity and energy for Sheridan, Wyoming from 2007 through 2016. We also have a contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 MW of capacity and energy. The agreement renews automatically and requires a seven-year notice of termination. Both contracts are served by Black Hills Power and are integrated into its control area and are treated as part of the utility's firm native load.
- We have a power purchase agreement with Basin Electric for the supply of 80 MW of capacity and energy through 2012 and a separate agreement to receive 80 MW of capacity and energy through 2012. The agreements were entered into with Basin Electric to accommodate delivery of electricity to Cheyenne Light's service territory.

RECLAMATION LIABILITY

Under its mining permit, WRDC is required to reclaim all land where it has mined coal reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land with an equivalent amount added to the asset costs. The asset is depreciated over the appropriate time period and the liability is accreted over time using an interest method of allocation. Approximately $0.6 million, $0.3 million and $0.6 million was charged to accretion expense for the years ended December 31, 2008, 2007 and 2006, respectively. Approximately $0.6 million, $0.5 million and $0.5 million was charged to depreciation expense for the years ended December 31, 2008, 2007 and 2006, respectively. Accrued reclamation costs included in Other in Deferred credits and other liabilities on the accompanying Consolidated Balance Sheets were approximately $17.7 million and $14.8 million at December 31, 2008 and 2007, respectively.

LEGAL PROCEEDINGS

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the consolidated financial statements are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in the consolidated financial statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2008, cannot be reasonably determined and could have a material adverse effect on the results of operations or financial position.

Earn-Out Litigation

During 2008, we settled two proceedings brought by former stockholders of Indeck, a company the Company acquired in 2000. The first proceeding, a civil lawsuit, was held in federal court in Illinois. The second proceeding was an arbitration proceeding brought under the terms of a merger agreement that provided for contingent payment of earn-out consideration to the former Indeck stockholders. On March 21, 2008, the parties settled the lawsuit, and on March 27, 2008, the trial court entered an order approving the settlement agreement. Under the settlement agreement, we agreed to pay additional earn-out consideration to the former Indeck stockholders. The aggregate value of the 451,465 shares of additional Black Hills common stock issued was recorded as additional goodwill of $10.9 million.

On September 19, 2008, the arbitrator issued its order in the Company's favor, holding that no earn-out consideration was due by reason of the impairment of the Las Vegas II facility, and its related impact upon the 2003 earn-out payment. The arbitrator, however, instructed us to pay approximately $4.0 million in earn-out consideration that we previously tendered for payment for the 2003 earn-out period. The United States District Judge confirmed this award on December 3, 2008. On December 19, 2008, we issued 142,339 shares of additional common stock to the former Indeck stockholders. We filed a Satisfaction of Judgment in the United States District Court on January 2, 2009. The value of the 142,339 shares of additional Black Hills Common Stock was recorded as additional goodwill. This settlement with the shareholders of Indeck relates to our Power Generation segment, of which we disposed of seven IPP plants. In accordance with SFAS 142, goodwill of this segment was allocated between discontinued operations and continuing operations. Additional goodwill of $3.3 million was recorded in continuing operations in 2008 for the earn-out litigation.

FERC Compliance Investigation

During 2007, following an internal review of natural gas marketing activities conducted within the Energy Marketing segment, we identified possible instances of noncompliance with regulatory requirements applicable to those activities. We have notified the staff of FERC of its findings. We have also evaluated public announcements of civil penalties that have been levied against other companies for violations of FERC regulatory requirements. We believe we have adequately reserved for the estimated potential penalty that could be levied on us. Although the outcome of any legal or regulatory proceedings resulting from these matters cannot be predicted with any certainty, and while the final resolution of these matters could have a material impact on the consolidated net income of any particular period, the outcome of this proceeding is not expected to have a material impact upon our overall consolidated financial position.

19 GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include guarantees of debt obligations, contractual performance obligations and indemnification for reclamation and surety bonds.

As of December 31, 2008, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2008	Year Expiring
Guarantee obligations of Enserco under an agency agreement	$ 7,000	2009
Guarantees of payment obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings	70,000	Ongoing
Indemnification for subsidiary reclamation/surety bonds	6,377	Ongoing
	$ 83,377	

We have guaranteed up to $7.0 million of the obligations of Enserco under an agency agreement whereby Enserco provides services to structure up to $123.5 million United States dollars (converted from $150.0 million Canadian dollars as of December 31, 2008) of certain transactions involving the buying, selling, transportation and storage of natural gas on behalf of another energy company. The guarantee expires in July 2009.

We have guaranteed up to $25.0 million of the obligations of Black Hills Utility Holdings for payment obligations arising from commodity-related physical and financial transactions with BP Energy Company and/or BP Canada Energy Marketing Corp. These commodity transactions secure natural gas supply for our gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

We have guaranteed up to $20.0 million of the obligations of Black Hills Utility Holdings for payment obligations arising from commodity-related physical and financial transactions with Northern Natural Gas Company. These commodity transactions secure natural gas supply for our gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

We have has guaranteed up to $25.0 million of the obligations of Black Hills Utility Holdings for payment obligations arising from commodity-related physical and financial transactions with PSCo. These commodity transactions secure natural gas supply for our gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

In addition, at December 31, 2008, we had guarantees in place totaling approximately $6.4 million for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

20 BUSINESS SEGMENTS

Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of December 31, 2008, substantially all of our operations and assets are located within the United States.

Prior to the third quarter of 2008, we managed our business in six reporting segments within two business groups: Utilities and Non-regulated Energy. Utilities consisted of two reporting segments, including the Electric Utility segment (Black Hills Power) and the combination Electric and Gas Utility segment (Cheyenne Light). Non-regulated Energy consisted of four reporting segments, including our Coal Mining, Energy Marketing, Power Generation, and Oil and Gas segments.

In the third quarter of 2008, we changed the reporting segments within our Utilities Group to reflect the significant change to our utility business resulting from the Aquila Transaction (see Note 21). The Utilities Group includes two reporting segments: Electric Utilities and Gas Utilities. We manage our electric and gas utility businesses predominantly by state; however, because our electric utilities and our gas utilities have similar economic characteristics, we aggregate our electric (and combination) utility businesses in the Electric Utilities reporting segment and our gas utility businesses in the Gas Utilities reporting segment. Electric Utilities includes the operating results of the regulated electric utility operations of Black Hills Power and Colorado Electric, and the regulated electric and natural gas utility operations of Cheyenne Light. The natural gas operations within our combination utility, Cheyenne Light, provide stable gross margins and overall financial results. Periodic variances are therefore rarely expected to significantly impact the operating results discussions for the Electric Utilities segment. Presentation of prior periods has been adjusted to reflect the combination of Black Hills Power and Cheyenne Light within the Electric Utilities segment. Gas Utilities, acquired in July 2008, consists of the operating results of the regulated natural gas utility operations of Colorado Gas, Iowa Gas, Kansas Gas, and Nebraska Gas.

The Company now conducts its operations through the following six reporting segments:

Utilities Group –

- Electric Utilities, which supplies electric utility service to areas in South Dakota, Wyoming, Montana and Colorado and natural gas utility services to Cheyenne, Wyoming and vicinity; and
- Gas Utilities, which supplies gas utility service to Colorado, Iowa, Kansas and Nebraska. The Gas Utilities were acquired in July 2008 as described in Note 21.

Non-regulated Energy Group –

- Oil and Gas, which produces, explores and operates oil and natural gas interests located in Colorado, Louisiana, Montana, Oklahoma, Nebraska, New Mexico, North Dakota, Wyoming, Texas and California;
- Power Generation, which produces and sells power and capacity to wholesale customers. The power plants are located in Wyoming and Idaho;
- Coal Mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; and
- Energy Marketing, which markets natural gas, crude oil and related services primarily in the western and central regions of the United States and Canada.

On July 11, 2008, we sold entities that owned seven IPP plants with a total capacity of 974 megawatts. The financial information related to these plants was previously reported in the Power Generation segment and has been reclassified to discontinued operations. Our remaining IPP assets will continue to be reported in the Power Generation segment.

On March 1, 2006, we sold the crude oil marketing and transportation operating assets of BHER and related subsidiaries (see Note 16). The financial information of BHER was previously reported in the Energy Marketing segment and has been reclassified to discontinued operations on the accompanying Consolidated Financial Statements.

December 31:	2008	2007
	(in thousands)	
Total assets		
Utilities:		
Electric Utilities	$ 1,485,040	$ 830,090
Gas Utilities	733,377	–
Non-regulated Energy:		
Oil and Gas	403,583	432,839
Power Generation	155,819	153,120
Coal Mining	75,872	58,024
Energy Marketing	339,543	380,385
Corporate	186,409	42,445
Discontinued operations	246	572,731
Total assets	**$ 3,379,889**	**$ 2,469,634**
Capital expenditures and asset acquisitions		
Acquisition costs:		
Payment for acquisition of net assets, net of cash acquired	$ 938,423	$ –
Utilities:		
Electric Utilities	186,237	104,963
Gas Utilities	19,337	–
Non-regulated Energy:		
Oil and Gas	89,169	72,153
Power Generation	5,105	128
Coal Mining	25,190	4,991
Energy Marketing	22	177
Corporate	11,033	22,316
Capital expenditures of continuing operations	1,274,516	204,728
Capital expenditures of discontinued operations	29,836	62,319
Total capital expenditures and asset acquisitions	$ 1,304,352	$ 267,047
Property, plant and equipment		
Utilities:		
Electric Utilities	$ 1,346,836	$ 1,010,925
Gas Utilities	428,279	–
Non-regulated Energy:		
Oil and Gas	648,419	559,394
Power Generation	158,726	155,228
Coal Mining	107,460	86,721
Energy Marketing	2,375	2,389
Corporate	13,397	32,778
Total property, plant and equipment	$ 2,705,492	$ 1,847,435

December 31:	2008	2007	2006
		(in thousands)	
External operating revenues			
Utilities:			
Electric Utilities	$ 472,174	$ 301,514	$ 323,003
Gas Utilities	277,076	–	–
Non-regulated Energy:			
Oil and Gas	106,347	101,522	95,078
Power Generation	38,011	38,658	40,688
Coal Mining	31,842	26,154	22,405
Energy Marketing	59,310	93,836	51,231
Corporate	–	–	46
Total external operating revenues	$ 984,760	$ 561,684	$ 532,451
Intersegment operating revenues			
Utilities:			
Electric Utilities	$ 1,245	$ 1,897	$ 2,352
Non-regulated Energy:			
Power Generation	170	–	–
Coal Mining	25,059	16,334	13,877
Corporate	267	–	–
Intersegment eliminations	(5,711)	(5,077)	(6,095)
Total intersegment operating revenues[(a)]	$ 21,030	$ 13,154	$ 10,134

[(a)] In accordance with the provisions of SFAS 71, intercompany fuel sales to our regulated utilities are not eliminated.

December 31:	2008	2007	2006
Depreciation, depletion and amortization			
Utilities:			
Electric Utilities	$ 37,648	$ 25,517	$ 25,216
Gas Utilities	14,142	–	–
Non-regulated Energy:			
Oil and Gas	38,549	34,192	30,176
Power Generation	4,627	5,051	5,339
Coal Mining	9,449	5,016	5,211
Energy Marketing	689	813	512
Corporate	2,159	1,178	1,061
Total depreciation, depletion and amortization	$ 107,263	$ 71,767	$ 67,515

December 31:	2008	2007	2006
		(in thousands)	
Operating income (loss)			
Utilities:			
Electric Utilities	$ 77,866	$ 53,312	$ 45,956
Gas Utilities	14,888	–	–
Non-regulated Energy:			
Oil and Gas	(71,188)	25,437	26,088
Power Generation	14,215	2,596	8,281
Coal Mining	4,293	6,177	6,916
Energy Marketing	30,135	51,769	24,008
Corporate	(13,682)	(13,576)	(8,399)
Intersegment eliminations	(650)	–	(714)
Total operating income	$ 55,877	$ 125,715	$ 102,136
Interest income			
Utilities:			
Electric Utilities	$ 2,041	$ 7,282	$ 3,208
Gas Utilities	376	–	–
Non-regulated Energy:			
Oil and Gas	215	317	156
Power Generation	8,951	20,180	17,969
Coal Mining	1,392	2,074	1,858
Energy Marketing	1,345	3,308	1,859
Corporate	47,425	60,138	61,312
Intersegment eliminations	(59,569)	(89,734)	(84,598)
Total interest income	$ 2,176	$ 3,565	$ 1,764
Interest expense			
Utilities:			
Electric Utilities	$ 25,335	$ 21,012	$ 16,176
Gas Utilities	8,501	–	–
Non-regulated Energy:			
Oil and Gas	5,307	8,974	7,120
Power Generation	20,600	26,098	27,629
Coal Mining	46	390	427
Energy Marketing	1,599	1,177	2,139
Corporate	52,304	57,264	61,053
Intersegment eliminations	(59,569)	(89,734)	(84,598)
Total interest expense	$ 54,123	$ 25,181	$ 29,946

December 31:	2008	2007	2006
		(in thousands)	
Income taxes			
Utilities:			
Electric Utilities	$ 18,882	$ 12,826	$ 11,607
Gas Utilities	2,447	–	
Non-regulated Energy:			
Oil and Gas	(26,001)	5,182	7,127
Power Generation	1,683	(2,625)	(2,087)
Coal Mining	2,190	2,091	2,819
Energy Marketing	10,180	19,746	6,419
Corporate	(38,776)	(4,793)	(2,532)
Intersegment eliminations	–	–	(250)
Total income tax (benefit)/expense	$ (29,395)	$ 32,427	$ 23,103
Income (loss) from continuing operations			
Utilities:			
Electric Utilities	$ 39,674	$ 31,633	$ 24,188
Gas Utilities	4,230	–	–
Non-regulated Energy:			
Oil and Gas	(49,668)	12,706	12,736
Power Generation	3,121	(3,471)	1,117
Coal Mining	4,033	6,107	5,877
Energy Marketing	19,689	34,178	17,322
Corporate	(72,596)	(5,872)	(5,514)
Intersegment eliminations	(650)	–	(464)
Total income (loss) from continuing operations	$ (52,167)	$ 75,281	$ 55,262

21 ACQUISITIONS

AQUILA TRANSACTION

On February 7, 2007, we entered into a definitive agreement with Aquila to acquire its regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa for $940 million, subject to customary closing adjustments. Based on working capital, capital expenditure and other adjustments, we paid $908.8 million in cash to Aquila and completed the acquisition on July 14, 2008. Additionally, approximately $29.6 million of fees and other costs were capitalized as part of the purchase price. We expect to finalize the purchase price adjustments and allocations in the first half of 2009. The purchase price was financed through our Acquisition Facility and from cash proceeds generated from the IPP Transaction.

This acquisition has been accounted for under the purchase method of accounting, and accordingly, the purchase price has been allocated to the acquired assets and liabilities based on preliminary estimates of the fair values of the assets purchased and liabilities assumed as of the date of acquisition. This estimated purchase price allocation is subject to working capital and closing adjustments within one year of the date of acquisition. Allocation of the purchase price (reflecting initial working capital adjustments) is as follows (in thousands):

Current assets	$	113,547
Property, plant and equipment		542,094
Derivative assets		4,695
Goodwill[(a)]		344,460
Intangible assets[(b)]		4,884
Deferred assets		68,134
	$	1,077,814
Current liabilities	$	95,205
Deferred credits and other liabilities		50,224
	$	145,429
Net assets	$	932,385

(a) $247.6 million and $96.9 million of goodwill was allocated to the Electric Utilities and to the Gas Utilities, respectively. All of this goodwill is expected to be fully tax deductible.

(b) Intangible assets include $3.9 million of easements and right-of-ways and $1.0 million of trademark and trade names. This amount is being amortized on a straight-line basis over 20 years.

The following unaudited pro-forma consolidated results of operations have been prepared as if the acquisition of the regulated utilities had occurred on January 1, 2008, 2007 and 2006, respectively (in thousands):

		December 31, 2008		December 31, 2007		December 31, 2006
Operating revenues	$	1,548,688	$	1,389,838	$	1,325,285
Income (loss) from continuing operations		(27,770)		107,712		78,088
Net income		129,477		130,238		103,730
(Loss) earnings per share –						
Basic:						
Continuing operations	$	(0.73)	$	2.91	$	2.35
Total	$	3.39	$	3.52	$	3.13
Diluted:						
Continuing operations	$	(0.73)	$	2.88	$	2.33
Total	$	3.39	$	3.48	$	3.09

The above pro-forma information is presented for informational purposes only and is not necessarily indicative of the results of operations that would have been achieved had the acquisition been consummated at that time; nor is it intended to be a projection of future results.

22 OIL AND GAS RESERVES AND RELATED FINANCIAL DATA (Unaudited)

BHEP has operating and non-operating interests in 1,096 developed oil and gas wells in ten states and holds leases on approximately 416,000 net acres.

COSTS INCURRED

Following is a summary of costs incurred in oil and gas property acquisition, exploration and development during the years ended December 31 (in thousands):

		2008		2007		2006
Acquisition of properties:						
Proved	$	15,710	$	–	$	64,265
Unproved		1,290		–		19,336
Exploration costs		13,703		7,250		21,752
Development costs		49,441		62,104		53,080
Asset retirement obligations incurred		5,029		1,934		4,468
	$	85,173	$	71,288	$	162,901

RESERVES

The following table summarizes BHEP's quantities of proved developed and undeveloped oil and natural gas reserves, estimated using constant year-end product prices, as of December 31, 2008, 2007 and 2006, and a reconciliation of the changes between these dates. These estimates are based on reserve reports by Cawley, Gillespie & Associates, Inc., an independent engineering company selected by the Company for 2008 and 2007. Estimates for 2006 are based on reserve reports by Ralph E. Davis Associates, Inc. Such reserve estimates are inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

	2008		2007		2006	
	Oil	Gas	Oil	Gas	Oil	Gas
	(in thousands of Bbls of oil and MMcf of gas)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	5,807	172,964	5,723	164,754	6,835	128,573
Production	(387)	(10,704)	(409)	(11,697)	(401)	(11,512)
Additions – acquisitions	2	3,352	–	–	–	59,813
Additions – extensions and discoveries	438	4,037	373	21,318	118	12,524
Revisions to previous estimates	(675)	(15,217)	120	(1,411)	(829)	(24,644)
Balance at end of year	5,185	154,432	5,807	172,964	5,723	164,754
Proved developed reserves at end of year included above	4,429	88,701	5,095	92,522	4,723	87,891
Year-end prices (NYMEX)	$ 44.60	$ 5.71	$ 95.98	$ 6.80	$ 61.05	$ 5.52
Year-end prices (average well-head)	$ 32.74	$ 4.44	$ 83.23	$ 5.88	$ 52.06	$ 5.34

Reserve additions totaled 10.0 Bcfe, replacing 77% of production. The purchase of additional working interests in Wyoming, exploration and development drilling in North Dakota and Wyoming, and detailed reserve work on Montana properties accounted for the majority of the additions. The purchase of additional working interests in Wyoming added 3.8 Bcfe. Drilling in North Dakota (Bakken Shale) and Wyoming (Teapot Sand) accounted for 3.0 Bcfe additions. North Dakota additions were constrained as a result of lease expirations driving drill site selection to lower working interest properties and edge of leasehold where proven undeveloped reserves can only be recognized in one direction. Wyoming bookings were limited by both year-end price and late year completion, limiting opportunity to recognize offset locations. A detailed review of the Montana assets in 2008 resulted in the addition of 2.6 Bcfe in future drilling locations.

The overall revision to reserves totaled 19.2 Bcfe with 78% of this revision, or 15.0 Bcfe, due to lower product prices and higher costs. Performance related revisions were 4.2 Bcfe (less than 2% of year-end 2007 reserve total). We experienced downward revisions in a portion of our San Juan Basin horizontal drilling program and had higher than expected depletion in some Piceance wells. Partially offsetting these downward revisions were positive revisions resulting from our workover program in San Juan Basin that increased production and reserves from existing wells through well clean-up, artificial lift and well-head compression projects.

CAPITALIZED COSTS

Following is information concerning capitalized costs for the years ended December 31, (in thousands):

	2008	2007	2006
Unproved oil and gas properties	$ 31,507	$ 37,459	$ 36,936
Proved oil and gas properties	561,779	475,061	409,984
	593,286	512,520	446,920
Accumulated depreciation, depletion & amortization and valuation allowances	(267,893)	(141,780)	(112,020)
Net capitalized costs	$ 325,393	$ 370,740	$ 334,900

RESULTS OF OPERATIONS

Following is a summary of results of operations for producing activities for the years ended December 31, (in thousands):

	2008	2007	2006
Revenues			
Sales	$ 106,019	$ 101,286	$ 94,682
Production costs	34,198	28,824	27,487
Depreciation, depletion & amortization and valuation provisions*	126,980	31,212	27,420
	161,178	60,036	54,907
Income tax (benefit) expense	(25,925)	5,303	7,180
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$ (29,234)	$ 35,947	$ 32,595

* Includes ceiling test adjustment of $91.8 million in 2008.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

Following is a summary of the standardized measure as prescribed in SFAS 69, of discounted future net cash flows and related changes relating to proved oil and gas reserves for the years ended December 31, (in thousands):

	2008	2007	2006
Future cash inflows	$ 875,926	$ 1,544,175	$ 1,238,962
Future production costs	(309,169)	(438,314)	(435,314)
Future development costs	(130,632)	(140,118)	(118,266)
Future income tax expense	(100,791)	(284,678)	(184,373)
Future net cash flows	335,334	681,065	501,009
10% annual discount for estimated timing of cash flows	(156,108)	(358,167)	(233,484)
Standardized measure of discounted future net cash flows	$ 179,226	$ 322,898	$ 267,525

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31, (in thousands):

	2008	2007	2006
Standardized measure – beginning of year	$ 322,898	$ 267,525	$ 397,469
Sales and transfers of oil and gas produced, net of production costs	(78,342)	(63,659)	(64,367)
Net changes in prices and production costs	(191,784)	107,920	(233,599)
Extensions, discoveries and improved recovery, less related costs	7,961	34,771	30,114
Net changes in future development costs	26,062	45,127	38,256
Revisions of previous quantity estimates, changes in production rates, changes in timing and other	(41,861)	(71,685)	(106,124)
Accretion of discount	42,485	33,852	56,002
Net change in income taxes	85,218	(30,953)	91,556
Purchases of reserves	6,592	–	58,218
Sales of reserves	(3)	–	–
Standardized measure – end of year	$ 179,226	$ 322,898	$ 267,525

Changes in the standardized measure from "revisions of previous quantity estimates, changes in production rates, changes in timing and other," are driven by reserve revisions, modifications of production profiles and timing of future development. For both 2008 and 2007, we had minimal net reserve revisions to prior estimates. Production forecast modifications are generally made at the well level each year through the reserve review process. These production profile modifications are based on incorporation of the most recent production information and applicable technical studies. Timing of future development investments are reviewed each year and are often modified in response to current market conditions for items such as permitting, service availability, etc.

23 QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth selected unaudited historical operating results and market data for each quarter of 2008 and 2007. All periods presented are adjusted to reflect the IPP Transaction as Discontinued operations.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2008				
Operating revenues	$ 152,850	$ 153,273	$ 291,892	$ 407,775
Operating income (loss)[(a)]	25,536	25,523	42,688	(37,870)
Income (loss) from continuing operations[(a)(b)]	11,739	13,150	19,522	(96,578)
Income (loss) from discontinued operations, net of taxes[(c)]	5,052	9,046	145,389	(2,240)
Net income (loss) available for common stock	16,791	22,196	164,911	(98,818)
Earnings (loss) per common share:				
Basic -				
Continuing operations	$ 0.31	$ 0.34	$ 0.51	$ (2.52)
Discontinued operations	0.13	0.24	3.79	(0.06)
Total	$ 0.44	$ 0.58	$ 4.30	$ (2.58)
Diluted -				
Continuing operations	$ 0.31	$ 0.34	$ 0.51	$ (2.52)
Discontinued operations	0.13	0.24	3.78	(0.06)
Total	$ 0.44	$ 0.58	$ 4.29	$ (2.58)
Dividends paid per share	$ 0.35	$ 0.35	$ 0.35	$ 0.35
Common stock prices				
High	$ 43.98	$ 39.66	$ 39.23	$ 31.59
Low	$ 33.21	$ 31.70	$ 30.10	$ 21.73

(a) Includes ceiling test impairment of $91.8 million pre-tax and $59.0 million after-tax in the fourth quarter.

(b) Includes unrealized mark-to-market charge for interest rate swaps of $61.4 million after-tax in the fourth quarter.

(c) Includes gain on the IPP Transaction of $139.7 million after-tax during the third quarter.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2007				
Operating revenues	$ 157,496	$ 133,526	$ 130,168	$ 153,648
Operating income	43,497	31,836	18,392	31,990
Income from continuing operations	26,879	19,489	11,128	17,785
Income from discontinued operations, net of taxes	5,574	5,609	6,336	5,972
Net income available for common stock	32,453	25,098	17,464	23,757
Earnings per common share:				
Basic -				
Continuing operations	$ 0.76	$ 0.52	$ 0.30	$ 0.47
Discontinued operations	0.16	0.15	0.17	0.16
Total	$ 0.92	$ 0.67	$ 0.47	$ 0.63
Diluted -				
Continuing operations	$ 0.75	$ 0.51	$ 0.29	$ 0.47
Discontinued operations	0.16	0.15	0.17	0.15
Total	$ 0.91	$ 0.66	$ 0.46	$ 0.62
Dividends paid per share	$ 0.34	$ 0.34	$ 0.34	$ 0.35
Common stock prices				
High	$ 39.63	$ 42.59	$ 44.48	$ 45.41
Low	$ 35.40	$ 36.86	$ 36.84	$ 40.21

24 SUBSEQUENT EVENTS

SALE TO MEAN

On January 20, 2009, we completed a sale of a 23.5% ownership interest in the Wygen I power generation facility to MEAN for $51.0 million. In connection with this sale, we entered into agreements under which MEAN will make payments for costs associated with administrative services, plant operations and coal supplied by our WRDC subsidiary during the life of the facility. Concurrently with this sale, we also terminated a 10-year power purchase contract under which MEAN was obligated to buy 20 MW of power annually from Wygen I.

GUARANTEES AND SURETY BONDS

On January 19, 2009, we issued a guarantee for up to $37.9 million to GE Packaged Power, Inc. for payment obligations arising from a purchase contract for a LMS100 gas turbine generator, which is forecasted for use in meeting the needs of our Colorado Electric customers. It is a continuing guarantee which terminates upon payment in full of the purchase price to GE. Payments are scheduled based upon estimated milestone dates with the final payment due September 29, 2010. The purchase contract also gives us a short-term option for the purchase of two additional LMS100 turbine generators at the same pricing as the first generator.

On January 20, 2009, we issued a surety bond for $9.2 million to MEAN to guarantee the payment or reimbursement of operating costs in the Wygen I ownership agreement. Black Hills Wyoming and MEAN entered into the ownership agreement when MEAN acquired a 23.5% ownership interest in the Wygen I plant. The surety bond expires on December 31, 2009.

SELECTED FINANCIAL DATA

Certain items related to 2007 through 2004 have been restated from prior year presentation to reflect the classification of the 2008 IPP Transaction as discontinued operations (see Notes 1 and 16 to Consolidated Financial Statements).

Years Ended December 31,	2008	2007	2006	2005	2004
Total Assets (in thousands)	$ 3,379,889	$ 2,469,634	$ 2,241,798	$ 2,120,258	$ 2,029,585
Property, Plant and Equipment (in thousands)					
Total property, plant and equipment	$ 2,705,492	$ 1,847,435	$ 1,661,028	$ 1,351,366	$ 1,142,537
Accumulated depreciation and depletion	(683,332)	(509,187)	(462,557)	(407,039)	(366,356)
Capital Expenditures (in thousands)	$ 1,304,352	$ 267,047	$ 308,450	$ 208,856	$ 90,974
Capitalization (in thousands)					
Current maturities	$ 2,078	$ 130,326	$ 4,249	$ 4,237	$ 4,026
Notes payable	703,800	37,000	145,500	55,000	24,000
Long-term debt, net of current maturities	501,252	503,301	554,411	558,725	536,834
Preferred stock equity	–	–	–	–	7,167
Common stock equity	1,050,536	969,855	790,041	738,879	728,598
Total capitalization	$ 2,257,666	$ 1,640,482	$ 1,494,201	$ 1,356,841	$ 1,300,625
Capitalization Ratios					
Short-term debt, including current maturities	31.3%	10.2%	10.0%	4.4%	2.1%
Long-term debt, net of current maturities	22.2	30.7	37.1	41.2	41.3
Preferred stock equity	–	–	–	–	0.6
Common stock equity	46.5	59.1	52.9	54.4	56.0
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Total Operating Revenues (in thousands)	$ 1,005,790	$ 574,838	$ 542,585	$ 496,768	$ 325,388

SELECTED FINANCIAL DATA CONTINUED

Years Ended December 31,	2008	2007	2006	2005	2004
Net Income (Loss) Available for Common (in thousands):					
Utilities	$ 43,904	$ 31,633	$ 24,188	$ 20,119	$ 19,209
Non-regulated Energy	(23,475)[1]	49,520	36,588	43,167	29,003
Corporate expenses and intersegment eliminations	(72,596)[2]	(5,872)	(5,514)	(13,491)	(3,790)
Income (Loss) from Continuing Operations Before Changes in Accounting Principles	(52,167)	75,281	55,262	49,795	44,422
Discontinued operations[3]	157,247	23,491	25,757	(16,375)	13,551
Preferred dividends	—	—	—	(159)	(321)
	$ 105,080	$ 98,772	$ 81,019	$ 33,261	$ 57,652
Dividends Paid on Common Stock (in thousands)	$ 53,663	$ 50,300	$ 43,960	$ 42,053	$ 40,210
Common Stock Data[4] (in thousands)					
Shares outstanding, average	38,193	37,024	33,179	32,765	32,387
Shares outstanding, average diluted	38,193	37,414	33,549	33,288	32,912
Shares outstanding, end of year	38,636	37,796	33,369	33,156	32,478
Earnings (Loss) Per Share of Common Stock[4] (in dollars)					
Basic earnings (loss) per average share -					
Continuing operations	$ (1.37)	$ 2.03	$ 1.67	$ 1.52	$ 1.37
Discontinued operations	4.12	0.63	0.77	(0.50)	0.41
Total	$ 2.75	$ 2.66	$ 2.44	$ 1.02	$ 1.78
Diluted earnings (loss) per average share -					
Continuing operations	$ (1.37)	$ 2.01	$ 1.65	$ 1.49	$ 1.35
Discontinued operations	4.12	0.63	0.77	(0.49)	0.41
Total	$ 2.75	$ 2.64	$ 2.42	$ 1.00	$ 1.76
Dividends Paid per Share	$ 1.40	$ 1.37	$ 1.32	$ 1.28	$ 1.24
Book Value Per Share, End of Year	$ 27.19	$ 25.66	$ 23.68	$ 22.28	$ 22.43
Return on Average Common Stock Equity (year-end)	10.4%	11.2%	10.6%	4.5%	8.1%

SELECTED OPERATING STATISTICS

Years ended December 31,	2008	2007	2006	2005	2004
Operating Statistics:					
Generating capacity (MW):					
Utilities (owned generation)	630	435	435	435	435
Utilities (purchased capacity)	420	50	50	50	50
Independent power generation(5)	141	983	989	1,000	1,004
Total generating capacity	1,191	1,468	1,474	1,485	1,489
Electric Utilities:					
MWh sold:					
Retail electric	3,532,402	2,636,425	2,552,290	2,472,051	1,509,635
Contracted wholesale	665,795	652,931	647,444	619,369	614,700
Wholesale off-system	1,551,273	678,581	942,045	869,161	926,461
Total MWh sold	5,749,470	3,967,937	4,141,779	3,960,581	3,050,796
Gas Utilities:					
Gas Dth sold	23,053,599	–	–	–	–
Transport volumes	26,805,075	–	–	–	–
Oil and gas production sold (MMcfe)	13,534	14,627	14,414	13,745	12,595
Oil and gas reserves (MMcfe)	185,542	207,806	199,092	169,583	173,417
Tons of coal sold (thousands of tons)	6,017	5,049	4,717	4,702	4,780
Coal reserves (thousands of tons)	274,000	280,000	285,000	290,000	294,000
Average daily marketing volumes:					
Natural gas physical sales (MMBtu)	1,873,400	1,743,500	1,598,200	1,427,400	1,226,600
Crude oil physical sales (Bbls) (6)	7,880	8,600	8,800	–	–

(1) Includes a $59.0 million after-tax ceiling test impairment charge to our crude oil and natural gas properties taken in 2008.
(2) Includes a $61.4 million after-tax unrealized mark-to-market loss related to interest rate swaps.
(3) 2008 includes a $139.7 million after-tax gain on the IPP Transaction and 2005 includes long-lived asset impairment charges of approximately $33.9 million after-tax
(4) In February 2007, we issued 4.2 million shares of common stock, which dilutes our earnings per share in subsequent periods.
(5) Includes 825 MW in 2007, 2006 and 2005, and 839 MW in 2004, which have been reported as "Discontinued operations."
(6) Represents crude oil marketing activities in the Rocky Mountain region, which began May 1, 2006.

For additional information on our business segments see Management's Discussion and Analysis of Financial Condition and Results of Operations, Quantitative and Qualitative Disclosures about Market Risk and Note 20 to the Consolidated Financial Statements in this Annual Report.

Board of Directors

David R. Emery, age 46, has been our Chairman, President and Chief Executive Officer since 2005. Prior to that, he held various positions with the Company, including President and Chief Executive Officer, President and Chief Operating Officer - Retail Business Segment and Vice President – Fuel Resources. He was elected to our Board of Directors in January 2004. Mr. Emery has 19 years of experience with us.

David C. Ebertz, age 63, is President of Dave Ebertz Risk Management Consulting, a firm specializing in insurance and risk management services for schools and public entities, since 2000. He has previous experience in the insurance industry. Mr. Ebertz has served on our Board of Dirvectors since 1998.

Jack W. Eugster, age 63, retired, was Chairman, Chief Executive Officer and President of Musicland Stores, Inc. from 1980 until his retirement in 2001. He was Non-Executive Chairman of Shopko Stores, Inc. a general merchandise discount store chain from 2001 to 2005. Mr. Eugster was elected to the Board of Directors in 2004 and currently chairs the Compensation Committee.

John R. Howard, age 68, retired, was President of Industrial Products, Inc., which provided equipment and supplies to the mining and manufacturing industries, from 1992 to 2003 and was Special Projects Manager for Linweld, Inc. Mr. Howard was elected to the Board of Directors in 1977 and currently chairs the Governance Committee.

Kay S. Jorgensen, age 58, is involved in numerous business activities and is Owner and Chief Executive Officer of KSJ Enterprises, LLC, providing marketing and development services since 2006. She was Former Owner and Chief Executive Officer of Jorgensen-Thompson Creative Broadcast Services, Inc., a radio broadcast services company, from 1997 to 2005. She previously served in the South Dakota State Legislature and on various state and local boards and commissions. Ms. Jorgensen has served on the Board of Directors since 1992 and currently serves as Presiding Director.

Stephen D. Newlin, age 56, is Chairman, President and Chief Executive Officer of PolyOne Corporation, a global premier provider of specialized polymer materials, services and solutions, since 2006. Prior to that he was President of the Industrial Sector of Ecolab, Inc., a global leader of services, specialty chemicals and equipment serving industrial and institutional clients, from 2003 to 2006. Mr. Newlin was elected to the Board of Directors in 2004.

Gary L. Pechota, age 59, is President and Chief Executive Officer of DT-TRAK Consulting, Inc., a medical billing services company, since December 2007. He was retired from 2005 to 2007. Prior to that he was Former Chief of Staff of the National Indian Gaming Commission from 2003 to 2005. He was a private investor and consultant from 2001 until 2003. Prior to that, he held executive positions in the cement industry and positions in finance and accounting. Mr. Pechota was elected to the Board of Directors in 2007.

Warren L. Robinson, age 58, retired, was Executive Vice President, Treasurer and Chief Financial Officer of MDU Resources Group, Inc., a diversified energy and resources company, from 1992 until his retirement in January 2006. Mr. Robinson was elected to the Board of Directors in 2007.

John B. Vering, age 59, is Managing Director of Lone Mountain Investments, Inc., agricultural and oil and gas investments, since 2002. He co-founded PMT Energy, LLC, a natural gas and exploration company focused on the Appalachia Basin in 2003. Mr. Vering was elected to the Board of Directors in 2005.

Thomas J. Zeller, age 61, has been President of RESPEC, a technical consulting and services firm with expertise in engineering, information technologies and water and natural resources since 1995. Mr. Zeller has been a member of the Board of Directors since 1997 and currently chairs the Audit Committee.

Executive Officers

David R. Emery, age 46, was elected Chairman in April 2005 and has been President and Chief Executive Officer and a member of the Board of Directors since January 2004. Prior to that, he was our President and Chief Operating Officer – Retail Business Segment from April 2003 to January 2004 and Vice President – Fuel Resources from January 1997 to April 2003. Mr. Emery has 19 years of experience with us.

Garner M. Anderson, age 46, has been Vice President, Treasurer and Chief Risk Officer since October 2006. He served as Vice President and Treasurer since July 2003. Mr. Anderson has 20 years of experience with us, including positions as Director – Treasury Services and Risk Manager.

Roxann R. Basham, age 47, has been Vice President – Governance and Corporate Secretary since February 2004. Prior to that, she was our Vice President – Controller from March 2000 to January 2004. Ms. Basham has a total of 25 years of experience with us.

Jeffrey B. Berzina, age 36, has been our Vice President – Finance since November 2008. He served as Assistant Controller from 2004 to 2008, and Director of Financial Reporting from 2002 to 2004. Mr. Berzina has 8 years of experience with us. Prior to joining us, he had six years of experience in public accounting.

Scott A. Buchholz, age 47, has been our Senior Vice President – Chief Information Officer since the close of the Aquila acquisition in July 2008. Prior to joining us, he was Aquila's Vice President of Information Technology from June 2005 until July 2008, Six Sigma Deployment Leader/Black Belt from January 2004 until June 2005, and General Manager, Corporate Information Technology from February 2002 until January 2004. He was employed with Aquila for 28 years.

Anthony S. Cleberg, age 56, has been Executive Vice President and Chief Financial Officer since July 2008. He was an independent investor, developer and consultant with companies in Colorado and Wyoming from 2002 until joining us in 2008. Prior to his consulting role, he was the Executive Vice President and Chief Financial Officer of two publicly-traded companies: Washington Group, International, Inc. a large engineering and construction company involved in power plant construction and mining operations, and Champion Enterprises, a builder of factory-built housing. Before his CFO roles, he spent 15 years in various senior financial positions with Honeywell International, Inc. and eight years in public accounting at Deloitte & Touche, LLP.

Linden R. Evans, age 46, has been President and Chief Operating Officer – Utilities since October 2004. Mr. Evans had been serving as the Vice President and General Manager of our former communication subsidiary since December 2003, and served as our Associate Counsel from May 2001 to December 2003. Mr. Evans has 7 years of experience with us.

Executive Officers

Steven J. Helmers, age 52, has been our Senior Vice President, General Counsel since January 2004. He served as our Senior Vice President, General Counsel and Corporate Secretary from January 2001 to January 2004. Mr. Helmers has 8 years of experience with us.

Richard W. Kinzley, age 43, has been our Vice President, Strategic Planning and Development since September 2008 and Director of Corporate Development from 2000 until September 2008. Mr. Kinzley has 9 years of experience with us. Prior to joining us, he had 9 years of experience in public accounting and 2 years of experience in industry.

Perry S. Krush, age 49, has been Vice President – Controller since December 2004. Mr. Krush has 20 years of experience with us, including positions as Controller – Retail Operations from 2003 to 2004, Director of Accounting for our subsidiary, now known as Black Hills Non-regulated Holdings and Accounting Manager – Fuel Resources from 1997 to 2003.

James M. Mattern, age 54, has been the Senior Vice President – Corporate Administration and Compliance since April 2003 and Senior Vice President-Corporate Administration from September 1999 to April 2003. Mr. Mattern has 21 years of experience with us.

Robert A. Myers, age 51, has been our Senior Vice President – Human Resources since January 2009 and served as our Interim Human Resources Executive since June 2008. He was a partner with Strategic Talent Solutions, a human resources consulting firm, from October 2006 until December 2008, Senior Vice President – Chief Human Resource Officer for Devon Energy from March 2006 until September 2006, and Senior Vice President and Chief Human Resource Officer at Reebok International, Ltd from November 2003 until January 2006. He has over 28 years of service in key human resources leadership roles.

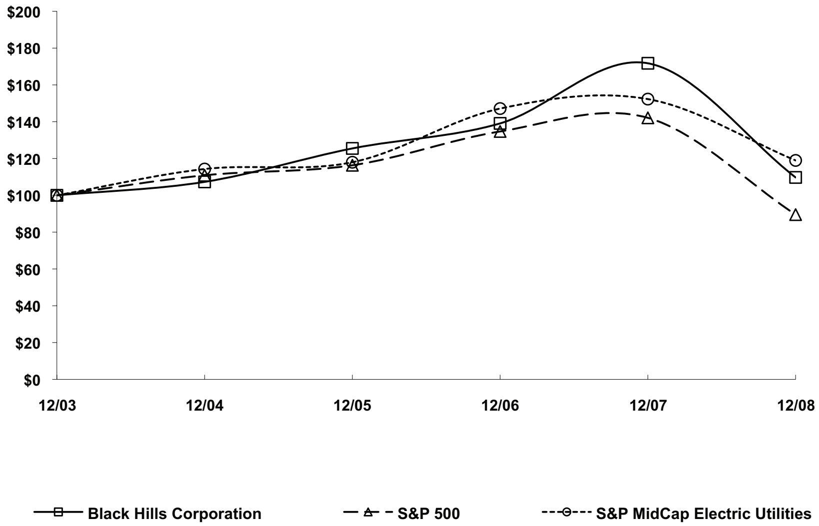
Thomas M. Ohlmacher, age 57, has been the President and Chief Operating Officer of our Non-regulated Energy Group since November 2001. He served as Senior Vice President – Power Supply and Power Marketing from January 2001 to November 2001 and Vice President – Power Supply from 1994 to 2001. Prior to that, he held several positions with our company since 1974. Mr. Ohlmacher has 34 years of experience with us.

Kyle D. White, age 49, has been Vice President – Corporate Affairs since January 2001 and Vice President – Marketing and Regulatory Affairs since July 1998. Mr. White has 26 years of experience with us.

Lynnette K. Wilson, age 49, has been our Senior Vice President – Communications and Investor Relations since the close of the Aquila acquisition in July 2008. Prior to joining us, she was Aquila's Vice President of Communications and Investor Relations from June 2006 until July 2008 and Issues Strategist for the Office of the Chairman and Chief Executive Officer from January 2002 until May 2006. She was employed with Aquila for 9 years.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Black Hills Corporation, The S&P 500 Index And S&P MidCap Electric Utilities



*$100 invested on 12/31/03 in stock & index-including reinvestment of dividends.
Fiscal year ending December 31.

Black Hills Corporation

Improving life with energy