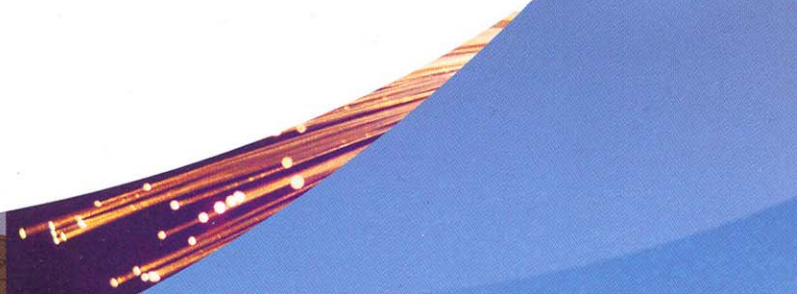


E N E R G Y   T O   C O N N E C T





## ENERGY TO CONNECT

### Corporate Mission

*We are a quality company,  
delivering exceptional customer value,  
creating opportunities for employees,  
and growing through responsible energy  
development in the West to achieve  
solid returns for investors.*

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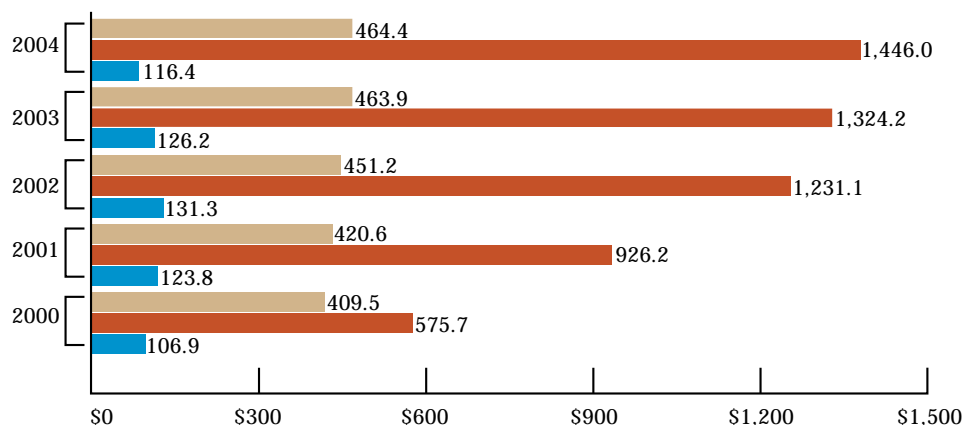
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16	SOCIAL RESPONSIBILITY
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	2004	2003	2002
Earnings per average share - diluted	\$1.76	\$1.97	\$2.26
Dividends paid per share	\$1.24	\$1.20	\$1.16
Book value per outstanding share	\$22.43	\$21.72	\$19.66
Year-end stock price	\$30.68	\$29.83	\$26.52
Five-year dividend growth rate	3.6 %	3.7 %	4.1 %
Payout ratio	70 %	61 %	51 %
Dividend yield on market value at year-end	4.0 %	4.0 %	4.4 %
Return on average common equity	8 %	10 %	12 %
Price-earnings multiple at year-end	17	15	12
Total utility electric sales (millions of KWhs)	3,051	2,926	2,946
Total independent power capacity (MW) at year-end*	964	1,002	950
Tons of coal sold (thousands of tons)	4,780	4,812	4,052
Oil and gas production sold (MMcfe)	12,595	10,843	7,398
Daily volume natural gas marketed (MMBtu)	1,741,100	1,241,900	1,088,200
Daily volume crude oil marketed (barrels)	44,900	58,700	57,200

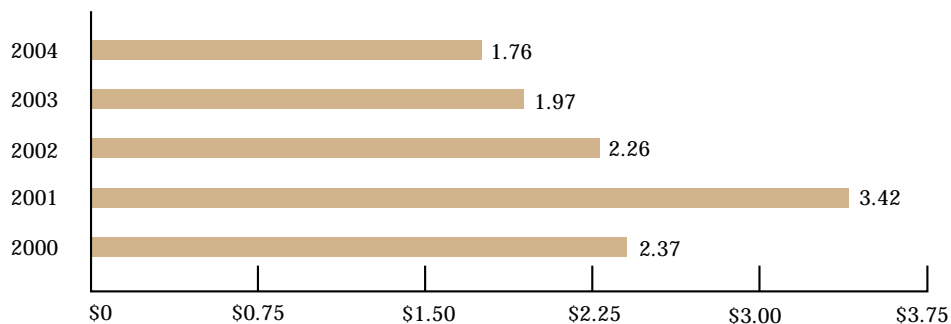
## >> CORPORATE HIGHLIGHTS

Business Group Assets \*\*  
(Smillion)

■ Retail Services  
■ Wholesale energy  
■ Communications



Earnings  
(Smillion)



Dividends



\* Includes 40 MW in 2003 and 82 MW in 2002 that are currently reported as "discontinued operations."

\*\* Excludes corporate assets and assets of discontinued operations.



DAVID R. EMERY  
President and  
Chief Executive Officer

*We continued to follow our  
proven business philosophy:  
we reward our shareholders  
by serving our customers  
with reliability and value.*

## ENERGY TO CONNECT

### To Our Shareholders

My first year as President and Chief Executive Officer was exciting, challenging and personally fulfilling. I am honored to lead this great organization and its team of dedicated employees. Through the transition of the past year, we continued to follow our proven business philosophy: we reward our shareholders by serving our customers with reliability and value. To that end, our Board of Directors recently raised the dividend to shareholders for the 35th consecutive year. Few energy companies can match our solid dividend record. Our decision to increase the dividend reflects our confidence in our abilities and opportunities.

#### Energy to grow

##### Expertise to get us there

In January 2005, we acquired Cheyenne Light, Fuel & Power. This utility provides electric service to 38,000 customers and natural gas distribution to 31,000 customers in and around Cheyenne, Wyoming. In addition to expanding our retail presence, Cheyenne is an excellent strategic fit, partly because it currently purchases all of its energy from others. Through the resource planning and regulatory review process, we plan to propose that Cheyenne Light own and operate its own power generation facilities after its existing all-requirements power service agreement expires in late 2007. We have a proven ability to generate reliable, competitively priced power, and welcome the opportunity to provide long-term value for our new power consumers in Cheyenne.

#### Review of 2004 operations

Our 2004 financial performance improved as the year progressed. Earnings for 2004 were \$57.7 million, or

\$1.76 per share, compared to \$61.0 million, or \$1.97 per share, in 2003. Per share income from continuing operations decreased 5 percent to \$1.74 in 2004. In the first half of the year, we responded to a number of issues, including:

- challenges that impeded our ability to meet production and performance goals at our oil and gas operations;
- difficult market conditions during the first quarter when our Las Vegas Cogeneration II power plant was operating as a “merchant” plant;
- unrealized losses caused by mark-to-market accounting rules governing our energy marketing operations;
- an earnings decline from certain power fund investments;
- lower earnings at Black Hills Power because of mild weather and the results of scheduled and unscheduled power plant outages; and
- competitive price pressure in our broadband communications business.

In the second half of the year, a more normalized earnings pattern emerged. The results of our 2004 operations are summarized by business segment below.

Oil and gas operations earned a record \$12.2 million, a 45 percent increase over 2003. Throughout much of the first three quarters, our production growth was hindered by delays in permitting, drilling and completing new wells as well as in constructing a critical gas gathering system and compressor stations. By year end, many of these challenges were largely overcome, and we established our





seventh consecutive annual production record, producing 12.6 billion cubic feet equivalent (BCFE) – a 16 percent increase over last year. Proved reserves increased 11 percent to 173 BCFE.

Our coal mine earned \$7.4 million, a 10 percent decrease from 2003. The lower results were primarily due to increased depreciation expense and a one-time coal tax settlement, which, when credited back to a customer, effectively reduced our average coal price received. Production of 4.8 million tons in 2004 was slightly less than in 2003.

Energy marketing operations earned \$10.2 million. Daily average natural gas marketing volumes increased 40 percent in 2004, and revenues from oil marketing and transportation were strong. The wholesale power generation subsidiary earned \$15.6 million from continuing operations, a decrease of 31 percent, due primarily to the contract change at our Las Vegas Cogeneration II facility. A new contract began in April 2004, which has stabilized our earnings from this business.

Black Hills Power earned \$19.2 million, a decline of 20 percent, due largely to the effects of scheduled and unscheduled power plant outages, mild weather and lower margins from off-system wholesale power sales.

Our communication segment reported a \$3.9 million loss, an improvement of \$2 million, or 33 percent, compared to 2003 results, primarily due to increased business customers and residential revenues. Despite competitive

pressures, we were able to solidify our customer base. Corporate expense was \$3.5 million, which was an improvement of \$4.1 million compared to 2003, as «more costs were allocated directly to subsidiaries. Certain administrative expenses increased, including costs for Sarbanes Oxley compliance, holding company structuring, pension and insurance.

#### **Strengthening internal practices**

In October 2004, Linden R. Evans was promoted to fill my former position as President and Chief Operating Officer of our Retail Services business group. We then began an internal reorganization aimed at improving productivity and reducing costs. We seek to combine and cross-train retail personnel, improve customer service, enhance corporate compliance and achieve greater efficiency.

We also centralized corporate governance activities and improved internal controls in compliance with the Sarbanes Oxley Act. We believe these steps strengthened our already high standards of ethics and business conduct. In addition, our status as a registered holding company imposed new accounting and reporting requirements. Our reorganization conforms to these mandates, and more readily enables us to pursue retail electric and gas opportunities across state borders.

These changes were costly, as higher outside professional services and additional internal resources increased our corporate overhead. Nevertheless, as a result of these efforts, the Company is in a stronger position to serve long-term investor interests.



*In many respects, 2004 was a year of transition, focusing on near-term issues. Even so, we also advanced our long-term goal of expanding our diversified energy base in a prudent and balanced manner.*

#### **Building upon a solid financial foundation**

We are committed to maintaining a strong balance sheet. Last year, we reduced long-term debt by more than \$100 million and refinanced an issue of pollution control revenue bonds to take advantage of a lower interest rate environment. Reflecting the success of our efforts, at year-end 2004, our debt to total capitalization was 51 percent. To maintain a strong liquidity position, we completed a \$125 million, one-year revolving credit facility in the spring of 2004, replacing an existing facility. We maintain additional availability under a \$225 million revolving credit facility that expires in the summer of 2006.

Our combined diversified businesses demonstrated another year of solid cash flows. In 2004, cash flows from operations were approximately \$133 million. Another \$50 million was invested in natural gas inventories at year-end 2004, which will be delivered to customers in early 2005. Cash outflows for investments during the year totaled approximately \$87 million, related to oil and gas development and general maintenance capital expenditures throughout our other businesses. Our stock price at year-end 2004 was \$30.68 – about 3 percent higher than the end of 2003. Combined with a dividend yield of 4 percent, total shareholder return for 2004 was 7 percent, a respectable result considering the earnings decline.

#### **Avenues for growth**

In many respects, 2004 was a year of transition, focusing on near-term issues described above. Even so, we also advanced our long-term goal of expanding our diversified energy base in a prudent and balanced manner. We continued to actively pursue ways to:

- **Increase our natural gas production.** We have a significant drilling and development program to exploit our gas reserves. We believe these opportunities will extend our production growth for several years to come.
- **Expand our power generation fleet.** We seek opportunities to provide power to other utilities through long-term contracts. This strategy should enable us to build new coal-fired base load power plants and gas-fired peaking plants.
- **Increase our energy marketing activity.** Since we are both a producer and consumer of energy, our marketing function optimizes the value of our fuel and generation assets. Our focus on customer services and the physical movement of energy is a proven business plan. To facilitate further growth, we seek to expand producer service and acquire additional mid-stream assets, especially in the Rocky Mountain region, where a concentration of gas marketing occurs.
- **Expand our retail presence.** We are reliable and competitive energy suppliers and seek to expand our retail utility operations. We have a long history of expert electric utility operations, from generation to transmission to distribution to customer service. Retail gas operations may be new to us, but we have been producers and marketers of gas for decades, and retail distribution extends our existing capabilities.

#### **Outlook for 2005**

In 2005, we expect income from continuing operations to increase, within a range of \$1.85 and \$2.00 per share. Among the factors expected to augment results are:



continued growth in oil and gas production, modest accretion from Cheyenne Light, a small improvement in communications, increased earnings due to a full year of contract revenues at the Las Vegas II power plant, and incremental cost savings from ongoing integration efforts. We also expect small earnings declines due to a planned maintenance outage at the Wyodak power plant, lower coal production due to the same plant outage, reduced oil marketing and transportation revenues and narrower gas marketing margins.

#### **Board and officer changes**

This year, we recognize Daniel P. Landguth for 36 years of dedicated service to Black Hills Corporation. In May, he retires and steps down as Chairman of the Board. Dan guided our Company during a time of tremendous opportunity, growth and change. He motivated and inspired us through leadership that combined a vision of excellence with high ethical standards. Thank you, Dan, for your friendship and lasting contributions.

In May 2004, Jack W. Eugster joined the Board of Directors. He replaced Everett E. Hoyt, who retired from the Company. Ev provided leadership through a period of significant expansion of our businesses. We heartily thank him for his years of service and dedication. As previously mentioned, Linden R. Evans was named President and Chief Operating Officer – Retail Services in October 2004. In December 2004, Perry S. Krush was appointed Vice President – Controller of the Corporation.

#### **Energy to connect**

##### ***The relationships that make it happen***

In a sense, we are in the business of connecting customers – to electric power, fuel resources and broadband communications. We also connect meaningfully to the broader communities where we live and conduct business. In all we do, we strive to deliver competitive value and quality service. Ultimately, we seek to connect in relationships where trust and dependability enhance the economic aspects of our dealings.

Our talented and motivated employee team exemplifies our energy to connect: with customers, as we earn their confidence and long-term business; with tribal leaders, as we work together to bring gas resources to market; with regulators and elected officials, as we cooperate to produce and deliver energy at reasonable rates; with fellow employees, as we build upon our skills collectively and improve the final result; and with investors, as we convert our efforts into strong earnings.

On behalf of the Board and employee team, thank you for your involvement with Black Hills Corporation. We look forward to a prosperous future together.

*David R. Emery*



*In all we do, we strive to deliver competitive value and quality service. Ultimately, we seek to connect in relationships where trust and dependability enhance the economic aspects of our dealings.*

## BLACK HILLS AT A GLANCE

### Energy to connect

We are a diversified energy and communications company. Our wholesale energy operations are conducted through Black Hills Energy. This subsidiary generates electricity, produces natural gas and oil, mines coal and markets energy. Retail operations include Black Hills Power, an electric utility and our founding business, providing service to the Black Hills region and also selling surplus power in wholesale markets; Cheyenne Light, Fuel & Power, a Wyoming electric and gas distribution company acquired in January 2005; and Black Hills FiberCom, which offers bundled broadband communications services in and near Rapid City, South Dakota.

#### BLACK HILLS ASSETS

-  Power Generation
-  Oil Production
-  Pipelines
-  Gas Production
-  Coal Mining
-  Utility
-  Energy Marketing
-  Communications

### *Regional market leader*



#### **Power Generation**

- 964 MW of power generation capacity.
- Plants concentrated in Colorado, Nevada, Wyoming and California.
- Nearly all our capacity is under long-term contracts with load-serving electric utilities.
- Our strategy is to continue expanding our operations in growth markets in the West by providing coal-fired baseload power and natural gas-fired peaking power capacity.

#### **Natural Gas and Oil Production**

- Development and acquisition strategy focuses on long-lived gas reserves.
- 173 BCFE proved reserves at year-end 2004.
- 82% of total reserves are natural gas.
- 2004 production – 12.6 BCFE – was the seventh consecutive annual record and a 16% increase over 2003.
- Production is concentrated in New Mexico, Colorado and Wyoming, with additional production in Montana, North Dakota, Nebraska, Oklahoma, Louisiana, Texas, the Gulf of Mexico and California.



#### **Energy Marketing**

- Focusing on energy delivery, we market and move natural gas and oil to markets primarily in the West.
- Natural gas marketing includes producer services and origination services for gas consumers. We move gas primarily from the Rockies and Canada to markets in the West.
- Pipelines in Texas are contracted to deliver crude oil between ports and key connecting points.
- Average daily marketing volumes in 2004: natural gas – 1.74 BCF, up 40%, a new record; crude oil – 44,900 barrels.



#### **Coal Mining**

- Our Powder River Basin coal mine near Gillette, Wyoming, supports low-cost mine mouth power generation.
- 294 million tons of coal reserves at year-end 2004 – a 55-year supply at current production rates.
- Coal production in 2004 was 4.8 million tons.

### *A strong local presence*



#### **Black Hills Power**

- Electric utility serving 62,000 customers in western South Dakota, southeastern Montana and north-eastern Wyoming.
- 435 MW of power generation plus 50 MW of purchased power under long-term contract.
- 392 MW peak demand.
- Regulatory rates unchanged in 10 years, providing stability to our customers and rewards to shareholders through off-system wholesale power sales and cost containment incentives.
- Surplus power may be sold in wholesale markets, with unique access to both eastern and western power grids through an AC-DC-AC transmission tie, providing 70 MW of transmission capacity between the grids.



#### **Cheyenne Light, Fuel & Power**

- Electric and natural gas distribution company serving 38,000 electric customers and 31,000 gas customers in Cheyenne and other parts of Laramie County, Wyoming.
- 163 MW peak electric demand; 5 million MMBTU annual gas delivery.
- Excellent strategic fit with other Wyoming-based energy assets.
- Acquired in January 2005.



#### **Black Hills FiberCom**

- Delivers bundled telephone, cable television and high-speed internet services through a state-of-the-art fiber optic/coaxial hybrid network.
- Nearly 27,000 customers at year-end 2004.
- Revenue-generating units – the total number of services subscribed by residential customers – was 56,800 at year-end 2004, a 6 percent increase over 2003.
- Phone directory publishing augments revenue sources.
- Focused on delivering superior products and services at competitive prices.

## RETAIL SERVICES

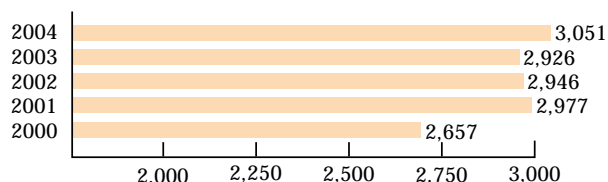
Serving as the lifeline for vital energy and communications services is a responsibility of the highest order, and that's how our retail companies deliver value and enhanced customer service. Connecting through electric lines, fiber optic lines, and now gas lines enables our retail customers to participate fully in all that modern life has to offer. Our electric and communications customers in the Black Hills and our electric and gas customers in Cheyenne know that they can count on us to make the human connection through personalized service, while meeting the basic needs of their homes and businesses.

### Connecting to customers

Black Hills Power, our flagship retail company, first brought electricity to the region in 1883. Our vertically-integrated utility generates power, sends it over transmission lines, and distributes it to over 62,000 customers throughout our three-state service territory. Black Hills

#### Electric utility sales

Thousands of megawatt-hours



Power employees are known for their connections to customers and communities.

Earnings at the utility were \$19.2 million in 2004, down 20 percent from the previous year. The decrease is primarily due to lower firm system sales, increased fuel and purchased power costs, higher costs related to scheduled and unscheduled maintenance, higher health insurance and higher allocated corporate costs. Higher off-system electric sales and reduced interest expense partially offset the negative impacts. Mild weather contributed to results, too, with degree-days down 11 percent in 2004.

Black Hills FiberCom, our retail telephone, internet and cable television company launched in 1998 to bring state-of-the-art communications services to much of the Black Hills, has grown to serve about 27,000 customers in Rapid City and the surrounding area. Withstanding the effects of a competitive "price war," FiberCom expanded its business customer base and increased residential revenues, improving performance by \$2 million in 2004. Because of the pioneering entrepreneurial spirit of Black Hills Corporation, businesses and individuals living in or relocating to the region have everything they need to connect with the rest of the world.





### **Cheyenne Light adds retail presence**

We extended the reach of our retail presence further into Wyoming with Cheyenne Light, Fuel & Power, the newest member of our retail family of companies. Cheyenne Light was acquired in January 2005. The combined gas and electric utility serves 38,000 electric and 31,000 natural gas customers in and around Wyoming's capital. Founded in 1900, Cheyenne Light is a logical fit for Black Hills. The companies' histories are similar, the communities they serve have the same Western spirit, and the employees of each have the same commitment to provide reasonably-priced and reliable service.

We have deep roots in Wyoming. Our coal mine operates in the Powder River Basin and power plants are located at the mine site. Black Hills Power provides retail and wholesale energy to Wyoming customers. We also produce oil and gas in the state. Cheyenne Light is a logical extension of our energy activities and we look forward to strengthening our ties to the people and economy of Wyoming.

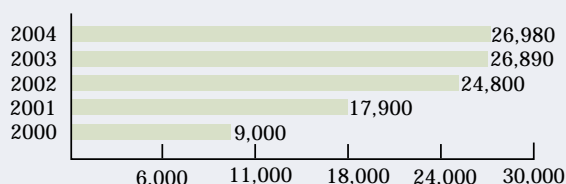
Together, the three retail companies are expected to provide a solid earnings base for Black Hills Corporation and position us to further develop our retail service expertise with future growth.

### **Integration enhances customer service**

To better serve customers of both Black Hills Power and Black Hills FiberCom, certain retail functions were integrated during 2004. Employees have been consolidated into a single service center where

### **Broadband communications**

Total customer count



customers can get all their energy and communications questions answered with one visit or phone call – 24 hours a day, seven days a week.

While we integrate functions to better serve the customer and reduce costs, we continue to account for these businesses as separate entities.

Black Hills Power has kept electric rates stable for more than a decade and its customer base is growing at a steady 1-2 percent a year. Despite competitive challenges, Black Hills FiberCom is achieving greater productivity, increased efficiency, and better bottom line performance.

### **Environmental and safety achievements**

Furthering our commitment to ensuring protection of the environment and the safety of our employees, we integrated our environmental and safety departments in 2004. Our environmental engineers conducted in-depth site reviews at all energy-related projects to assure compliance, and our safety team led the effort to prevent accidents and occupational illnesses.



Our employees earned a number of difficult-to-achieve safety awards this year, including 250,000 hours without a lost time accident for Black Hills Power's Ben French Station, Southern Hills linemen and servicemen, Northern Hills linemen and servicemen, Wyodak Coal Mine, and Harbor Cogeneration.

**Connected to our communities**

Open doors assure interaction, and we invite our customers and community groups to visit us in person despite the industry trend toward distancing the process through call centers. As a result, we know many of our customers personally.

Our employees have the energy to connect, and the communities we serve are better as a result.



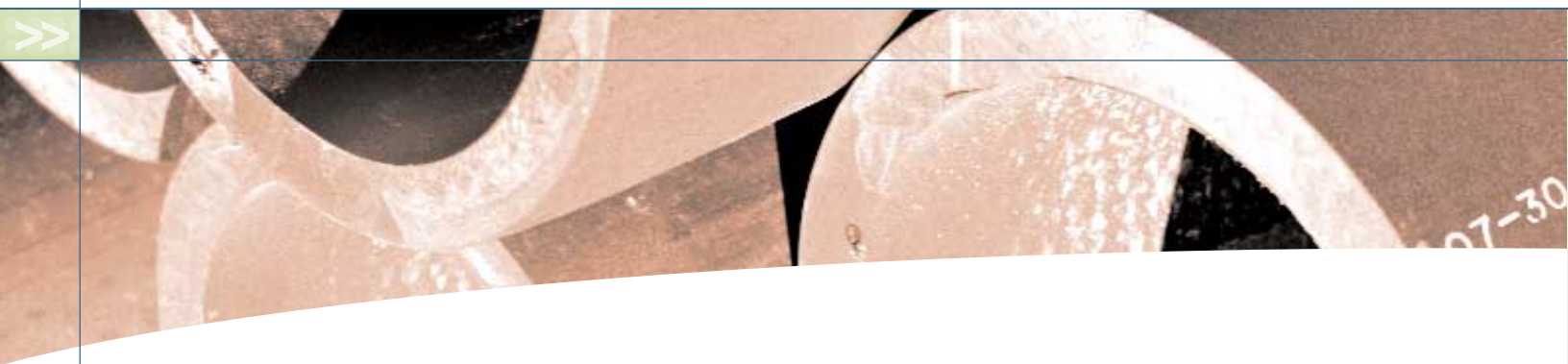
*Our energy diversification is instrumental to our long-term growth strategy. We excel in this approach because our operations complement and strengthen each other.*







## WHOLESALE ENERGY



Black Hills Energy, our wholesale energy subsidiary, generates electric power, produces natural gas and oil, mines coal and markets energy. In 2004, these activities represented about 70 percent of our asset base and nearly 80 percent of our income from continuing operations. Our energy diversification is instrumental to our long-term growth strategy. We excel in this approach because our operations complement and strengthen each other.

For example, we are both a consumer and producer of natural gas, and we create a business advantage from the two operations. Our power generation benefits from an indirect fuel hedge, protecting against price volatility. This also applies to coal mining operations, where the fuel is directly tied to our generation. Our ability to harness the energy value of low cost coal gives us a vital competitive edge in the marketplace for baseload power. This integration model also extends to our energy marketing businesses, which optimize the value of our power generation and fuel production assets.

Effective risk management is another key aspect of our wholesale business strategy. Nearly all of our power generation is provided under long-term contracts to load-serving utilities. The power purchaser bears the fuel risk

under most of these agreements. Likewise, nearly all of our coal production is under long-term contracts, most of which are life-of-plant agreements. We employ hedges on a portion of our oil and gas production to assure strong, stable cash flows as market conditions change.

Our energy marketing operations are governed by strict practices minimizing market risk, such as back-to-back trading positions and low value-at-risk tolerances. We monitor our credit exposure to counterparties on a continual basis. Our business diversity itself is also a way to manage our overall risk profile, with no heavy reliance on a single energy segment to deliver financial results. As a result, our risk-managed, diversified and integrated energy approach gives us both flexibility and stability as we continue advancing our prudent and balanced growth agenda.

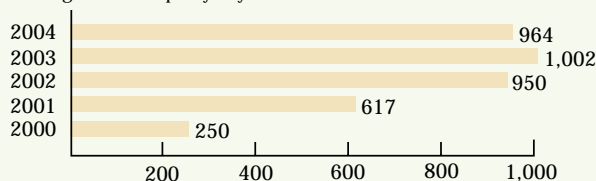
### **Power generation performance rebounds**

In April 2004, we began operating our Las Vegas Cogeneration II power plant under a new long-term tolling contract with Nevada Power Company. With that accomplished, our power generation business is expected to demonstrate a more stable earnings profile. In 2004, this business segment earned \$15.6 million from continuing operations.



### Non regulated power generation

In megawatts of capacity at year-end.\*



\*(The years 2000-2003 include certain discontinued operations)

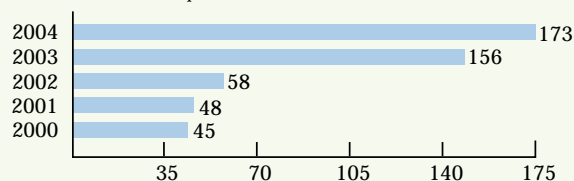
Our operated fleet of wholesale power plants is located in Colorado, Nevada, Wyoming, California and Idaho. Most of our 964 megawatts of generation capacity is used in peak demand periods. Several peaking plants are strategically located in regions of population and economic growth. We believe some of these sites will have the opportunity to increase capacity, through turbine additions or combined-cycle expansions, as demand for power increases. We also seek to build mine-mouth baseload power plants, either at our Wyodak energy complex or in other regions where coal resources are available near growing load centers.

### Record oil and gas production

Our oil and natural gas operations had another good year, with record earnings of \$12.2 million. For the seventh consecutive year, production achieved a new record, with 12.6 billion cubic feet equivalent (BCFE) produced in 2004, a 16 percent increase. Reserves also increased 11 percent, to a record-high 173 BCFE of proved developed and proved undeveloped reserves. These achievements were accomplished by our ambitious deployment of drilling and development capital.

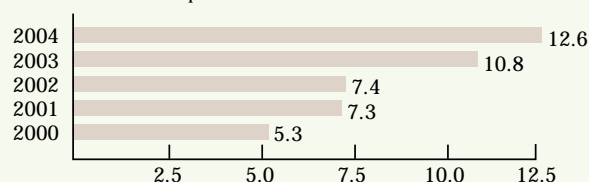
### Oil and gas reserves

In billion cubic feet equivalent



### Oil and gas production

In billion cubic feet equivalent



Last year, we drilled or participated in 161 exploratory and development wells (43 net wells), completing 127 wells (36 net) by year end. Our overall success rate exceeded 88 percent in 2004, taking into account a number of wells in progress at year end. With our extensive inventory of undeveloped locations and the advancement of our planned development program in San Juan Basin of New Mexico, we fully expect a continuation of production and reserve growth for the next several years. While not yet explored on our properties in the San Juan Basin, additional reserves are believed to exist in deeper drilling zones known to be productive elsewhere in the basin.

### Stable coal mining operations

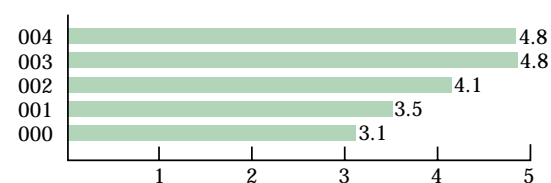
Our Wyodak coal mine is a steady performer, earning \$7.4 million from continuing operations in 2004. Production of 4.8 million tons was slightly down from



the record level set in 2003, due in part to planned and unplanned outages at power plants utilizing our coal. Coal reserves were 294 million tons at year-end 2004 – representing a 60-year supply at current production rates. We also are pleased the Wyodak Mine was recently presented the prestigious *Sentinels of Safety* award sponsored by the federal Mine Safety Health Administration.

#### Coal production

In millions of tons



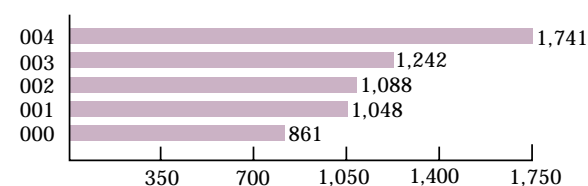
#### Solid energy marketing performance

Marketing operations increased earnings to \$10.2 million in 2004. We increased average gas volumes marketed by 40 percent last year, to more than 1.7 BCF per day. Best described as a “physical” marketing strategy, we offer producer services, assisting natural gas producers with collection, storage, transportation and marketing. We also are very active at the other end of the pipeline. Our origination services focus on arranging supplies and scheduling shipments of natural gas to larger consumers: primarily

utilities, manufacturers and industry. In the case of oil, we operate two pipelines in Texas, which link port areas to major connection points about 200 miles to the north. In addition to oil transportation services, we also provide oil marketing expertise to our clientele.

#### Gas marketing average daily volume

In thousands of MMBtu (million British thermal units)



#### Connecting to the customer

Delivering quality customer service and competitive value unites our diversified activities. This is a core business philosophy, because we believe long-term relationships create the best and most productive climates for growth. With that vision guiding us over time, we see opportunities to expand our power generation operations, increase production and reserves of natural gas, oil and coal, and provide additional marketing services to both existing and new customers.



*Our ability to harness the energy value of low-cost coal gives us a vital competitive edge in the marketplace for baseload power.*



*The best way to create and sustain long-term value is to stay connected to the people and our environment.*

## SOCIAL RESPONSIBILITY



Black Hills Corporation believes in responsible energy stewardship and contributory corporate citizenship. Our connections with the people we serve and the natural resources we utilize exemplify our respect for the earth and those who inhabit it.

Whether developing gas and oil reserves on the pristine Jicarilla Apache Nation of New Mexico or extracting coal in the Powder River Basin of Wyoming, we abide by the West's strict environmental standards. We proudly operate both gas-fired and coal-fired power plants that are among the cleanest in the nation.

We are integral to the communities we serve, not only with the vital products we deliver but also with our employees who have the energy to connect and make a difference. Our employees volunteer tirelessly to causes involved with children and the elderly, health care and community outreach, economic development and civic leadership. We make community events happen.

Social responsibility and high ethical standards permeate all aspects of the Company, from governance and accounting to our work to caring for our customers – wholesale, retail, regulated, and unregulated alike. We are committed to providing returns for our shareholders, and we know the best way to create and sustain long-term value is to stay connected to the people and our environment.

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## Management's Discussion and Analysis of Financial Condition and Results of Operations and Quantitative and Qualitative Disclosures about Market Risk

We are a diversified energy holding company operating principally in the United States with two major business groups – wholesale energy and retail services. We report for our business groups in the following financial segments:

Business Group	Financial Segment
Wholesale energy group	Power generation
	Oil and gas
	Coal mining
	Energy marketing and transportation
Retail services group	Electric utility
	Communications

Our wholesale energy group, which operates through Black Hills Energy, Inc. and its subsidiaries, engages in the production of electric power through ownership of a diversified portfolio of generating plants and the sale of electric power and capacity primarily under long-term “tolling” contracts; the production of coal, natural gas and crude oil primarily in the Rocky Mountain region; and the marketing and transportation of fuel products. Our retail services group currently consists of our electric utility, Black Hills Power, and communications segments. In future filings, we will report the operations of our new combination electric and gas public utility, CLF&P, as its own segment.

Our electric utility, Black Hills Power, Inc., generates, transmits and distributes electricity to an average of approximately 62,000 customers in South Dakota, Wyoming and Montana. Our communications segment provides broadband telecommunication services to approximately 27,000 residential and business customers in Rapid City and the Northern Black Hills region of South Dakota through Black Hills FiberCom, LLC.

In May 2004, we sold our subsidiary, Landrica Development Corp., which held some land and coal enhancement facilities that were previously reported in our coal mining segment.

In 2003, we decided to divest of our non-strategic power generation assets located in the Northeastern United States. On September 30, 2003, we sold our seven hydroelectric power plants located in Upstate New York. We currently hold for sale our 40 megawatt Pepperell power plant in Massachusetts.

In 2002, we discontinued operations of our coal marketing business due to difficulties in marketing our Wyodak coal from the Powder River Basin of Wyoming to East Coast markets. The non-strategic assets were sold effective August 1, 2002.

## Industry Overview

The energy and telecommunications industries are expected to become increasingly competitive due to a variety of regulatory, economic and technological changes. In addition, the energy sector has become more volatile due to international tensions, changes in investment activity and factors affecting supply and demand of various energy resources.

In recent years, state and federal regulators have been evaluating the results of energy deregulation efforts of the 1990s. These efforts were intended to encourage competition, introduce consumer choice and attract additional investment in energy resources. In many states, electric utilities were required to disaggregate traditional functions of generation, transmission, distribution and marketing of electricity in an effort to open markets to competition. Due to a number of causes, energy consumers have been exposed to significant price increases and deterioration in service in recent years. Because the benefits of a more competitive industry were not always evident, many regulators are now seeking new policy directions to assure greater reliability and end-user value in the future.

A surge in investment in gas-fired power generation facilities occurred in the early 2000s. Some of that investment led to an overabundance of power capacity in certain regions of the country. In some instances, “merchant” or non-contracted plants became financially distressed as market prices for power fell below the cost of production for extended periods during the 2002-2004 time frame. Many of these plants were deemed impaired and asset values were written down. Several companies abandoned their independent power production (IPP) strategy, sold their plants and exited the sector. IPP facilities under contract with utilities have fared better than those subject to volatile market conditions.

Mild weather over vast sections of the U.S. in 2003 and 2004, combined with slower regional economic growth, contributed to a slowdown in electric energy demand nationwide. As a result of excess energy supply, wholesale power prices have been relatively soft for much of the last two years. This situation could turn around abruptly with a resurgence of hotter than normal weather during the summer peaking season and increases in industrial demand. In addition, the availability of hydroelectric power is unpredictable and dependent on precipitation in the northwestern U.S. Power prices in the West can be affected dramatically by changing hydroelectric conditions.

The energy industry experienced a financial crisis beginning in late 2001, stemming from the collapse of Enron Corporation and the near collapse of several

other leading energy companies. The aggregate market capitalization of energy companies fell on the scale of hundreds of billions of dollars, reflecting challenging market conditions and investor attitudes. Investors and consumers lost confidence in the financial health and future prospects of many energy providers as a result of numerous events. Accordingly, energy companies have been subject to much greater scrutiny by regulators, credit rating agencies and investors. In response, companies are moving aggressively to improve liquidity and to restructure their balance sheets. They are abandoning unsuccessful business strategies, selling non-core assets, downsizing staffs, issuing new equity, canceling acquisitions, postponing or canceling construction projects, reducing significant levels of capital expenditures, accelerating debt repayment and realigning trading activities around their own generation, mid-stream and transportation assets.

The oil and gas industry has experienced significant price volatility in the past several years, from a lower-price environment in 2002 and 2003 to significantly higher prices for both commodities in 2004 and 2005 to date. In the 2000's, natural gas has emerged as the national industrial fuel of choice. Most of the recent increase in power generation capacity has been gas-fired, which in turn has exposed the generation companies' financial performance to greater risk due to fuel price volatility. Recent high product prices have encouraged domestic oil and gas producers to increase production and reserves. In addition, investment in liquefied natural gas port facilities is expected to increase the availability of gas supplies in future years.

The U.S. coal industry has experienced a resurgence in the past two years, with favorable commodity prices creating attractive returns. Coal prices in Wyoming's Powder River Basin have increased moderately during this period, due to the coal's lower heat content and high transportation costs. Those factors limit the ability to capture significant additional market share. However, from a regional perspective, Powder River Basin coal can be a very competitive energy resource. Fossil fuel combustion continues to be an international policy issue, with opponents arguing environmental harm, despite the application of advanced emissions technology. Because coal continues to be an economical resource, its long-term prospects as an important component of a national energy mix remain strong.

The telecommunications industry underwent widespread changes brought about by, among other things, the Telecommunications Act of 1996 and the decisions of federal and state regulators to open the monopolistic local telephone and cable television markets to competition. The industry has also experienced the rapid introduction of new broadband technology applications

and increased consumer demand for faster, higher-capacity, digital-based and expanded broadband communications services, including broader video choices and high speed data and Internet services. The convergence of these trends allowed many new entrants into the telecommunications market. Due to the rapid expansion of the broadband industry and the effects of technical substitution and obsolescence of equipment, the broadband communications industry's financial performance has suffered in many U.S. markets.

### **Business Strategy**

We are a customer-focused energy provider. Our business is comprised of fuel assets, electric generation assets and retail utility assets, such as electric and gas distribution systems. To optimize the value of those assets, we utilize our energy marketing and transportation expertise. Our focus on customers, whether retail utility customers or wholesale generation or marketing customers, provides us with opportunities to expand our various businesses. The diversity of our operations avoids reliance on any single business to achieve our strategic objectives. This diversity is expected to provide a measure of stability to our business and financial performance in volatile or cyclical periods. It should help us reduce our total corporate risk and allow us to achieve higher than average market returns over the long term. The strength and stability of our balance sheet is critical in today's market. Access to capital, sufficient liquidity and quality of earnings are our key drivers.

Our balanced, integrated approach to fuel production, power generation, retail operations and energy marketing is supported by disciplined risk management practices. Additionally, building on the strength of our electric utility, Black Hills Power, we enhanced our Black Hills area operations by providing broadband communications to our customers in South Dakota.

Our long-term strategy is to continue growing our core retail utility, generation and fuel asset businesses, supplemented by our energy marketing and transportation operations. We will do this primarily by focusing on customers. In the retail area, we will focus on acquiring new customers through the acquisition of additional retail utility properties, while maintaining our high customer service and reliability standards. In the power generation area, we will focus on long-term contractual relationships with key wholesale customers, as well as new customers, to allow us to expand existing generation sites, or to construct or acquire new generation facilities. Finally, in the fuel area, we will strive to develop additional markets for our production, including the development of additional power plants at our mine site. The expertise of our energy marketing and transportation businesses will continue to enable us to optimize the value of our asset businesses.

The following are key elements of our business strategy:

- operate our lines of business as retail and wholesale energy components. The retail component consists of electric, natural gas and telecommunications products and services. The wholesale component consists of fuel production, marketing, mid-stream assets and power production facilities;
- preserve Black Hills Power's low-cost rate structure for our residential, commercial and industrial customers while retaining the flexibility to selectively market excess generating capacity off-system to maximize returns in changing market environments;
- expand retail operations through selective acquisitions of electric utilities consistent with our regional focus and strategic advantages;
- improve our communications business by increasing customer service and value, by increasing revenues and by creating additional operating efficiencies;
- build and maintain strong relationships with wholesale energy customers;
- conduct business with a diversified group of creditworthy or sufficiently collateralized counterparties;
- sell a large percentage of our capacity and energy production from new independent power projects through mid- and long-term contracts primarily to load serving utilities in order to secure a stable revenue stream and attractive returns;
- grow our power generation segment by developing and acquiring power generating assets in targeted Western markets and, in particular, by expanding generating capacity of our existing sites through a strategy known as "brownfield development;"
- exploit our fuel cost advantages and our operating and marketing expertise to produce power at attractive margins;
- increase our reserves of natural gas and crude oil and expand our overall fuel production;
- increase margins from our coal production through an expansion of mine-mouth generation and increased coal sales;
- grow our energy marketing operations primarily through the expansion of producer and end-use origination services; and
- manage the risks inherent in energy marketing by maintaining position limits that minimize price risk exposure.

***Operate our lines of business as retail and wholesale energy components. The retail component consists of electric and telecommunications products and services. The wholesale component consists of fuel production, marketing, mid-stream assets and power production facilities.***

Through the retail and wholesale groups of our business, operating efficiencies are achieved. In the retail group, the integration of customer service and marketing and promotional efforts streamline operating processes and improve productivity. In the wholesale group, the fuel production, marketing and generation segments integrate balanced, yet diverse strategic operations.

***Preserve Black Hills Power's Low-Cost Rate Structure for our Residential, Commercial and Industrial Customers While Retaining the Flexibility to Selectively Market Excess Generating Capacity Off-System to Maximize Returns in Changing Market Environments.***

Through a settlement with the SDPUC Black Hills Power has been under a retail rate freeze since 1995. The rate freeze agreement terminated on January 1, 2005. The rate freeze preserved Black Hills Power's low-cost rate structure at levels below the national average for our retail customers while allowing us to retain the benefits from cost savings and wholesale "off-system" sales. This has provided us with flexibility in allocating Black Hills Power's generating capacity to maximize returns in changing market environments. We have historically optimized the utilization of Black Hills Power's power supply resources by selling wholesale power to other utilities and to power marketers in the spot market and through short-term sales contracts. Absent any request for a rate change by us or the SDPUC, rates will remain unchanged from those in place during the rate freeze.

***Expand Retail Operations Through Selective Acquisitions of Electric Utilities Consistent with our Regional Focus and Strategic Advantages.***

For more than 60 years, we have provided strong retail services, based on delivering quality and value to our customers. That tradition and accomplishment is expected to support efforts to expand our retail operations in other markets, most likely in the West and in regions that permit us to take advantage of our intrinsic competitive advantages, such as baseload power generation and system reliability. The January 2005 acquisition of CLF&P is an example of these expansion efforts. Retail operations also can augment other important business development, including transmission and pipelines and storage infrastructure, which could lead to advancing other wholesale operations. Regulated retail operations can contribute substantially to the stability of our long-term cash flows and earnings.



***Improve Our Communications Business by Increasing Customer Service and Value, by Increasing Revenues, and by Creating Additional Operating Efficiencies.***

We are now the leading provider of telephone, cable television and high-speed Internet services in the areas we serve. This accomplishment was initially due to the strength of Black Hills Power's reputation for reliability, customer service and value. More recently, our improvement in operations is due primarily to our service deliverability, reliability and commitment to our broadband customers. We believe this dual strategy – upholding our strong public standing and delivering superior broadband communications products and services – will advance our efforts further in the future. As we continue to seek additional customers and revenue, we will also continue efforts to create operating efficiencies by integrating appropriate business functions with related utility operations, benefiting customers as well as both business segments.

***Build and Maintain Strong Relationships With Wholesale Energy Customers.***

We strive to build strong relationships with utilities, municipalities and other wholesale customers, who we believe will continue to be the primary providers of electricity to retail customers in a deregulated environment. 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 meet our customers' 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 the more volatile spot markets.

***Conduct Business with a Diversified Group of Credit-worthy or Sufficiently Collateralized Counterparties.***

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 accomplish this by establishment of counterparty credit limits, continuous credit monitoring, and regular review of compliance with our credit policy by our executive credit committee that reports to our board of directors.

***Sell a Large Percentage of our Capacity and Energy Production From New Independent Power Projects Through Mid- and Long-Term Contracts Primarily to Load Serving Utilities in Order to Secure a Stable Revenue Stream and Attractive Returns.***

By selling the majority of our energy and capacity under mid- and long-term contracts, 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. Our goal is to sell a substantial majority of our unregulated power generation assets under long-term pre-approved contracts primarily to load serving utilities.

***Grow our Power Generation Segment by Developing and Acquiring Power Generating Assets in Targeted Western Markets, and in Particular, by Expanding Generating Capacity of our Existing Sites Through a Strategy Known as "Brownfield Development."***

We aim to develop power plants in regional markets based on prevailing supply and demand fundamentals in a manner that complements our existing fuel assets and fuel and energy marketing capabilities. This approach seeks to capitalize on market growth while managing our fuel procurement needs. Over the next few years, we intend to grow through a combination of disciplined acquisitions and development of new power generation facilities primarily in the western regions where we believe we have the detailed knowledge of market fundamentals and competitive advantage to achieve attractive returns. We believe the following trends will provide us with growth opportunities in the future:

- Demand for electricity in certain Western regions is expected to grow and new generation capacity will be required over the next several years.
- New electric generation construction will be predominantly gas-fired, which may create further competitive cost advantages for new and existing coal-fired generation assets.
- Transmission construction will significantly lag new generation development, favoring new development located near load centers or existing, unconstrained transmission locations.
- Disaggregation of the electric utility industry from traditionally vertically integrated utilities into separate generation, transmission, distribution and marketing entities may continue in certain regions, thereby creating opportunities for expansions, acquisitions and joint ventures.

We believe that existing sites with opportunities for brownfield expansion generally offer the potential for greater returns than development of new sites through a "greenfield" strategy. Brownfield sites typically offer several competitive advantages over greenfield development, including:

- proximity to existing transmission systems;
- operating cost advantages related to ownership of shared facilities;
- a less costly and time consuming permitting process; and
- potential ability to reduce capital requirements by sharing infrastructure with existing facilities at the same site.

We expanded our capacity with brownfield development at our Valmont and Wyodak sites in 2001, Arapahoe and Las Vegas sites in 2002 and our Wyodak site in 2003. We believe that our Fountain Valley, Wyodak and Las Vegas sites in particular provide further opportunities for significant expansion of our gas- and coal-fired generating capacity over the next several years.

***Exploit our Fuel Cost Advantages and our Operating and Marketing Expertise to Produce Power at Attractive Margins.***

We expect to expand our portfolio of power plants having relatively low marginal costs of producing energy and related products and services. As an increasing number of gas-fired power plants are brought into operation, we intend to utilize a low-cost power production strategy, together with access to coal and natural gas reserves, to protect our revenue stream. Low marginal 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. We aggressively manage each of these factors with the goal of achieving very low production costs.

Our primary competitive advantage is our coal mine, which is located in close proximity to our retail service territories. We are exploiting the competitive advantage of this native fuel source by building additional mine-mouth coal-fired generating capacity. This strengthens our position as a low-cost producer since transportation costs often represent the largest component of the delivered cost of coal.

***Increase our Reserves of Natural Gas and Crude Oil and Expand our Overall Fuel Production.***

Our strategy is to expand our natural gas reserves through a combination of acquisitions and drilling programs. We aim to maintain sufficient natural gas production either to directly serve or indirectly hedge the fuel cost exposure of our gas-fired generation plants. Specifically, we plan to:

- substantially increase our natural gas reserves while minimizing exploration risk by focusing on lower-risk exploration and development drilling as well as acquisitions of proven reserves;
- exploit opportunities based on our belief that the long-term demand for natural gas will remain strong by emphasizing natural gas in our acquisition and drilling activities; and
- add natural gas reserves and increase production by focusing primarily on various shallow gas plays in the Rocky Mountain region, where the added production can be integrated with our fuel marketing and/or power generation activities.

***Increase Margins From our Coal Production Through an Expansion of Mine-Mouth Generation and Increased Coal Sales.***

Our strategy is to expand our coal production through the construction of mine-mouth coal-fired generation plants at our Wyodak mine location. Our objective is to maintain coal reserves to serve our mine-mouth coal-fired generation plants directly. Specifically, we plan to:

- increase coal production and sales from our Wyodak mine by continuing to develop additional mine-mouth generating facilities at the site; and
- pursue future sales of coal from the Wyodak mine to regional additional rail-served and truck-served customers.

***Grow our Energy Marketing Operations Primarily Through the Expansion of Producer and End-use Origination Services.***

Our energy marketing activities distinguish themselves from other marketing businesses by focusing on customer services and the physical delivery of energy commodities. With our producer services, we primarily assist natural gas producers in the Rocky Mountain region of the U.S. and Canada with marketing and transporting their commodities to the marketplace. We also provide origination services, where we work with industrial consumers of natural gas, by sourcing and arranging delivery for gas. We expect, because of our regional marketing expertise and proven knowledge of efficiently utilizing storage and transportation infrastructure, that we can increase our marketing volumes as well as provide services to optimize the value of our fuel and generation assets. In the future, we may acquire additional mid-stream assets, such as regional pipelines and storage systems, so that we can facilitate and further augment our marketing services.

***Manage the Risks Inherent in Energy Marketing by Maintaining Position Limits That Minimize Price Risk Exposure.***

Our 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 for each of our marketing companies that establish price risk exposure levels. We formed oversight committees to monitor compliance with our policies. We also limit exposure to energy marketing risks by maintaining separate credit facilities for each of our marketing companies.

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## Prospective Information

We continue to advance our business strategy. We expect long-term growth through the expansion of integrated, balanced and diverse energy operations. We recognize that sustained growth requires continued capital deployment. We believe that we are strategically positioned to take advantage of opportunities to acquire and develop energy assets consistent with our investment criteria and a prudent capital structure.

Our wholesale energy group was our largest contributor to revenue and earnings in 2004 and 2003. We expect that earnings from this group over the next few years will be driven primarily by increased oil and gas production and expansion in power generation. In March 2003 we acquired Mallon Resources Corporation, an energy company engaged in oil and natural gas exploration, development and production primarily in the San Juan Basin of New Mexico. This acquisition more than doubled our reserves, and contributed to a 16 percent increase in production volumes compared to 2003 levels. Although we expect long-term growth in our power generation segment, 2005 power generation earnings are expected to return to a more normalized earnings profile due to the new Las Vegas Cogeneration II contract with Nevada Power Company that began April 1, 2004. We expect lower earnings from our energy marketing and transportation segment due to anticipated decreases in oil marketing and transportation revenue, and lower margins from gas marketing.

Firm electric business at our electric utility, Black Hills Power, remained healthy in 2004. We believe that Black Hills Power will produce modest growth in revenue, and absent unplanned plant outages, it will continue to produce stable earnings for the next several years. We forecast firm energy sales in our retail service territory to increase over the next 10 years at an annual compound growth rate of approximately one percent, with the system demand forecasted to increase at a rate of two percent. These forecasts are derived from studies conducted by us whereby we examined and analyzed our service territory to estimate changes in the needs for electrical energy and demand over a 20-year period. These forecasts are only estimates, and the actual changes in electric sales may be substantially different. Weather deviations can also affect energy sales significantly when compared to forecasts based on normal weather. The portion of the utility's future earnings that will result from wholesale off-system sales will depend on many factors, including native load growth, plant availability, electricity demand and commodity prices.

On January 1, 2005, the South Dakota retail rate freeze under which Black Hills Power has operated since January 1, 2000, expired. The current South Dakota retail electric rates, along with the Wyoming retail

electric rates, have been in place since the summer of 1995. These rates, which have remained flat for 10 years, do not include a fuel and/or purchased power adjustment clause but allow Black Hills Power to retain the benefits of off-system wholesale sales and cost reductions. Black Hills Power has no current plans to request approval to change its retail electric rates. Black Hills Power's return is affected by changes in inflation, capital investment, capital markets, and retail and wholesale power sales. Black Hills Power monitors these potential impacts in order to ensure that its return remains adequate for its investment to serve customers.

In January 2005 we acquired Cheyenne Light, Fuel & Power (CLF&P) from Xcel Energy Inc. CLF&P is a utility serving residential, commercial and industrial energy consumers in and around Cheyenne, Wyoming. Currently the utility has approximately 38,000 electric customers and 31,000 gas customers. Its peak load is 163 megawatts and power is provided under an all-requirements contract with PSCo, which extends through 2007. CLF&P's annual natural gas sales and transportation during 2004 were approximately 13.6 million MMBtus, with sales to commercial and residential customers accounting for approximately 4.4 million MMBtus and transportation accounting for approximately 9.2 million MMBtus. We anticipate modest accretion to earnings from the CLF&P acquisition in 2005. A condition of the settlement stipulation approved by the WPSC when it authorized Black Hills Corporation to acquire CLF&P prohibits us from increasing CLF&P's gas or electric base rates prior to January 1, 2006. CLF&P's rates are separated into commodity energy related charges and charges that recover the costs of operating the natural gas and electric distribution systems (base rates). The commodity energy costs are forecasted annually for recovery on a current basis from customers. Also included for recovery/refund are any over or under collections, plus interest, occurring during the prior year. Another condition of the settlement stipulation is that CLF&P is required to file with the WPSC an updated resource plan prior to June 1, 2005. The resource plan will provide information regarding the options being considered for meeting its electricity requirements after December 31, 2007, when the current all-requirements power supply agreement with PSCo expires.

We expect improved results from our broadband communications business in 2005 due to increased revenues and continued improvement in cost containment measures. Integration of certain retail functions will improve customer service and productivity. The recovery of our capital investment and future profitability are dependent primarily on our ability to sustain our customer base and control our expenses, and is subject to the risk of market competition



and the risk that technological advances may render our network obsolete. If we determine that we will be unable to recover our investment, we would be required to record a non-cash charge to earnings, in an amount that could be material, in order to write down a portion of our investment. While we do not anticipate being regulated in the local markets, we are unable to predict future markets, future government impositions or future economic and competitive conditions that could affect the profitability of our communications operations.

Part of our long-term growth strategy includes continued capital deployment. We have forecasted capital expenditures of \$50 million, \$55 million and \$96.2 million a year in 2005, 2006 and 2007, respectively, in new projects or acquisitions which are yet to be identified. In addition, our capital requirements forecast includes \$38.7 million, \$43.9 million and \$47.1 million in 2005, 2006 and 2007, respectively, of oil and gas expenditures and \$90.0 million in 2005 for the CLF&P acquisition, and \$50.0 million and \$18.1 million in 2006 and 2007, respectively, for the development of a coal fired plant. Actual deployment of the capital will be dependent on identifying and obtaining or developing projects that meet our investment criteria.

## Results of Operations

### CONSOLIDATED RESULTS

#### Overview

Revenue and income (loss) from continuing operations provided by each business group as a percentage of our total revenue and net income were as follows:

	2004	2003	2002
Revenue:			
Wholesale energy	81%	83%	79%
Retail services	19	17	21
	100%	100%	100%

Income (loss) from continuing operations:			
Wholesale energy	79%	81%	66%
Retail services	27	32	39
Corporate	(6)	(13)	(5)
	100%	100%	100%

In May 2004, we sold our subsidiary, Landrica Development Corp., which held some land and coal enhancement facilities that were previously reported in our coal mining segment.

In 2003, we sold our hydroelectric power plants located in upstate New York. The non-strategic assets were sold effective September 30, 2003. We also developed a plan of sale for our 40 MW Pepperell power plant, our last power plant in the Eastern region. These discontinued operations were previously reported in the Power generation segment. During the second quarter of 2002,

we adopted a plan to dispose of our coal marketing subsidiary, Black Hills Coal Network, due primarily to difficulties in marketing our Wyodak coal from the Powder River Basin of Wyoming to Midwestern and Eastern coal markets. We sold the non-strategic assets effective August 1, 2002. These discontinued operations were previously reported in the Energy marketing and transportation segment. Results of operations for 2003 and 2002 have been restated to reflect the operations discontinued.

#### 2004 Compared to 2003

Consolidated income from continuing operations for 2004 was \$57.2 million, compared to \$56.5 million in 2003, or \$1.74 per share in 2004, compared to \$1.82 per share in 2003. Income from discontinued operations was \$0.7 million or \$0.02 per share in 2004, compared to \$9.9 million or \$0.32 per share in 2003. Return on average common equity in 2004 and 2003 was 8.1 percent and 9.9 percent, respectively.

The wholesale energy group's income from continuing operations decreased \$0.4 million in 2004 compared to 2003. Increased income from continuing operations of \$3.8 million at our oil and gas operations and \$3.5 million from energy marketing and transportation operations were offset by decreased earnings from power generation of \$6.8 million and from coal mining of \$0.9 million.

The retail services group's income from continuing operations decreased \$3.0 million in 2004 compared to 2003. Earnings from continuing operations from the electric utility decreased \$4.9 million due to lower margins received, increased maintenance expense and general and administrative costs, offset by lower interest expense. The communication segment's losses decreased \$1.9 million in 2004 compared to 2003 due to increased revenues and lower operating costs, offset by increased marketing costs and corporate cost allocations.

Corporate costs for the year ended December 31, 2004 decreased \$4.1 million after tax, compared to 2003. The decrease is primarily due to increased allocations to subsidiaries and a \$1.0 million pre-tax gain on sale of assets, partially offset by increased costs related to Sarbanes-Oxley compliance, and holding company structuring and higher pension, insurance and interest expense. The Company's subsidiary, Daksoft, Inc., recorded a \$1.0 million pre-tax gain on the sale of its campground reservation system. As Daksoft now primarily provides information technology support to the Company, its results of operations are included in Corporate. Prior to 2004, Daksoft's results were included in the Communications segment.

## 2003 Compared to 2002

Consolidated income from continuing operations for 2003 was \$56.5 million, compared to \$58.1 million in 2002, or \$1.82 per share in 2003, compared to \$2.14 per share in 2002. Income from discontinued operations was \$9.9 million or \$0.32 per share in 2003, compared to \$2.4 million or \$0.09 per share in 2002. Return on average common equity in 2003 and 2002, was 9.9 percent and 11.8 percent, respectively.

The 2003 earnings per share results were impacted by an approximate 14 percent increase in diluted weighted average shares outstanding primarily related to the dilutive effect of the April 2003 common stock offering in which 4.6 million shares were issued. In addition, results for 2003 included the impact of several non-recurring items that had a net effect of decreasing 2003 results by approximately \$1.2 million after-tax. These items included:

- a \$3.0 million after-tax charge in our energy marketing and transportation segment for a settlement with the Commodity Futures Trading Commission (CFTC);
- a net after-tax charge of \$1.9 million in our power generation segment for the impact of a \$114.0 million contract termination payment received at the Las Vegas II plant, offset by the related \$117.2 million impairment charge taken on that plant;
- a \$1.8 million after-tax benefit for unrealized gains on plant investments accounted for on a fair value method of accounting at our equity-method power funds;
- a \$1.5 million after-tax benefit from a legal settlement at our Las Vegas II plant; and
- a \$0.4 million after-tax benefit from an Enron bankruptcy settlement.

In addition, 2002 results were affected by a non-recurring \$1.9 million after-tax benefit for the collection of previously reserved amounts at our power generation segment.

Corporate costs for the year ended December 31, 2003 increased \$4.6 million after tax, compared to 2002. The increase was primarily due to a \$3.9 million net increase in interest expense, increased healthcare costs and corporate tax expense. Net interest costs increased due to increased borrowings from the \$250 million debt issuance in May 2003 and the low returns on short-term investments.

Discussion of results from our operating groups and segments is included in the following pages.

*The following business group and segment information does not include discontinued operations or intercompany eliminations. Accordingly, 2003 and 2002 information has been revised to remove information related to operations that were discontinued.*

## Wholesale Energy Group

(in thousands)	2004	2003	2002
Revenue:			
Power generation	\$ 158,037	\$ 284,567*	\$ 102,548
Energy marketing and transportation**	662,110	675,586	553,688
Oil and gas	59,534	46,977	26,486
Coal mining	31,967	34,777	31,335
Total revenue	911,648	1,041,907	714,057
Operating expenses**	(817,898)	(948,830)*	(644,951)
Operating income	\$ 93,750	\$ 93,077	\$ 69,106
Income from continuing operations	\$ 45,447	\$ 45,843	\$ 38,176

\* Power generation revenue in 2003 includes \$114.0 million of contract termination revenue and operating expenses in 2003 includes \$117.2 million of impairment of long-lived assets (see Notes 13 and 14 of our Notes to Consolidated Financial Statements).

\*\* All periods presented reflect a net presentation of revenues at our gas marketing subsidiary and a gross presentation of revenues at our crude oil marketing subsidiary in accordance with EITF 02-3 and EITF 99-19.

## 2004 Compared to 2003

Income from continuing operations from the Wholesale Energy group for 2004 was \$45.4 million, compared to \$45.8 million in 2003.

Power generation segment income from continuing operations decreased to \$15.6 million in 2004 from \$22.4 million in 2003 primarily due to lower revenues at the Las Vegas II and Harbor plants, higher fuel costs at the Las Vegas I plant, and decreased earnings from unconsolidated subsidiaries, offset by lower fuel costs at the Gillette combustion turbine and lower interest expense. Income from continuing operations from our energy marketing and transportation businesses increased \$3.5 million due to increased gas marketing volumes and higher margins received and increased oil transportation revenues and oil marketing margins. These increases were partially offset by 2004 unrealized mark-to-market losses of \$1.1 million, pre-tax. Oil and gas income from continuing operations increased \$3.8 million due to a 16 percent increase in volumes sold and an increase in sales prices for oil and gas, partially offset by increased production expenses. Coal mining income from continuing operations decreased \$0.9 million due to a decrease in revenues resulting from scheduled and unscheduled plant outages, and higher depreciation expense, offset by lower general and administrative and direct mining costs.

In addition, 2003 results were \$1.2 million lower due to the impact of several non-recurring items as noted below.

## 2003 Compared to 2002

Income from continuing operations from the Wholesale Energy group for 2003 was \$45.8 million, compared to \$38.2 million in 2002. Results for 2003 include the impact of several non-recurring items that had a net effect of decreasing 2003 results by approximately \$1.2 million after-tax. These items include:

- a \$3.0 million after-tax charge in our energy marketing and transportation segment for a settlement with the Commodity Futures Trading Commission (CFTC);
- a net after-tax charge of \$1.9 million in our power generation segment for the impact of a \$114.0 million contract termination payment received at the Las Vegas II plant, offset by the related \$117.2 million impairment charge taken on that plant;
- a \$1.8 million after-tax benefit for unrealized gains on plant investments accounted for on a fair value method of accounting at our equity-method power funds;
- a \$1.5 million after-tax benefit from a legal settlement at our Las Vegas II plant; and
- a \$0.4 million after-tax benefit from an Enron bankruptcy settlement.

In addition, 2002 results were affected by a non-recurring \$1.9 million after-tax benefit for the collection of previously reserved amounts at our power generation segment.

Power generation segment income from continuing operations increased to \$22.4 million in 2003 from \$12.5 million in 2002, primarily due to earnings from 314 megawatts of additional capacity that was placed into service early in 2003, partially offset by increased related operating, interest and depreciation costs and fourth quarter losses at the 224 megawatt Las Vegas II plant as prevailing regional power market conditions limited the economic dispatch subsequent to the termination of the plant's long-term contract. Income from continuing operations from our energy marketing and transportation businesses decreased to \$6.7 million in 2003, compared to \$12.7 million in 2002 primarily due to the CFTC settlement and a 10 percent decrease in natural gas margins received, partially offset by a 14 percent increase in natural gas volumes marketed and increased earnings from oil pipelines. Oil and gas income from continuing operations increased to \$8.4 million in 2003 compared to \$4.8 million in 2002. Results improved due to a 47 percent increase in volumes sold, primarily related to the March 2003 acquisition of Mallon Resources, and higher prices received during 2003, partially offset by higher depletion and operating costs. Coal mining income from continuing operations in 2003 increased to \$8.3 million compared to \$8.1 million in 2002, due to a 19 percent increase in tons sold, which was partially offset by higher general and administrative and direct mining costs related to the increased production volumes.

## POWER GENERATION

Our power generation segment produced the following results:

(in thousands)	2004	2003	2002
Revenue:	\$158,037	\$284,567*	\$102,548
Operating income	47,934	58,893	35,362
Income from continuing operations	15,562	22,429	12,523

\* Power generation revenue in 2003 includes \$114.0 million of contract termination revenue (see Note 13 of our Notes to Consolidated Financial Statements).

Independent Power Capacity	2004	2003	2002
MW's of independent power capacity in service <sup>(b)</sup>	964	962	950 <sup>(a)</sup>
MW's of independent power capacity under construction	-	-	90

(a) Includes the 224 MW expansion at the Las Vegas II power plant which was placed into service on January 3, 2003.

(b) Capacity in service includes 82 megawatt (Pepperell and hydroelectric) in 2002, which is reported as "Discontinued operations."

## 2004 Compared to 2003

Power generation segment income from continuing operations decreased to \$15.6 million in 2004 from \$22.4 million in 2003. Earnings decreased primarily as the result of lower earnings at our Las Vegas II plant. During the first quarter of 2004, prevailing regional power market conditions limited the economic dispatch of this plant subsequent to the termination of the plant's long-term contract in September 2003, and for the remainder of the year, lower contract rates on the new long-term contract. The lower revenue was partially offset by lower depreciation expense at that plant. The decline in segment earnings was also due to higher fuel costs at Las Vegas I; lower revenues at our Harbor plant, offset by lower fuel cost, due to the expiration of a summer peaking agreement; and higher interest expense due to the December 31, 2003 consolidation of our Wygen plant. Equity in earnings of unconsolidated subsidiaries decreased \$3.4 million after-tax primarily due to the impact of mark-to-market adjustments at certain power fund investments that use a fair value method of accounting. These items were partially offset by lower fuel costs at our Gillette combustion turbine, a benefit from certain tax adjustments, lower interest expense due to the pay-down of debt, and higher earnings from other revenues. In addition, the segment's 2003 earnings were affected by certain non-recurring items, netting to a benefit of approximately \$1.8 million after-tax.



## 2003 Compared to 2002

Income from continuing operations increased \$9.9 million in 2003 compared to 2002 primarily due to increased generation capacity in operation, partially offset by related increases in interest, depreciation, fuel and other operating costs. The increase in income was partially offset by fourth quarter losses at the 224 megawatt Las Vegas II plant as the prevailing regional power market conditions limited the economic dispatch subsequent to the termination of the plant's long-term contract in September 2003. In addition, 2003 results include several non-recurring items that had a net effect of increasing 2003 results by \$1.8 million after-tax. These items include:

- a net \$1.9 million after-tax charge for the impact of a \$114.0 million contract termination payment at the Las Vegas II plant, offset by the related \$117.2 million non-cash impairment charge taken on the plant;
- a \$1.8 million after-tax benefit for unrealized gains on plant investments accounted for on a fair value method of accounting at our equity method power fund investments;
- a \$1.5 million after-tax benefit from a legal settlement at our Las Vegas II plant; and
- a \$0.4 million after-tax benefit from an Enron bankruptcy settlement.

In addition, 2002 results were affected by a non-recurring \$1.9 million after-tax benefit for the collection of previously reserved amounts.

2003 revenue and operating expense increased 177 percent and 235 percent, respectively, over 2002. The revenue increase is primarily related to \$114.0 million contract termination revenue and energy sales and capacity payments on the 224 megawatt gas-fired Las Vegas II plant and the 90 megawatt coal-fired Wygen plant, both of which went into operation early in 2003 and the 50 MW Arapahoe expansion completed in the latter part of 2002. The Las Vegas II plant received capacity and energy payments under a long-term contract only through September 22, 2003, the contract termination date. After the contract termination, the Las Vegas II plant sold power into the market only when it was economic to do so. In December 2003 a new long-term tolling arrangement was entered into with Nevada Power Company, which became effective April 1, 2004. Increased operating expense was primarily due to the \$117.2 million asset impairment charge, related to the contract termination and the increased depreciation, fuel, and other operating costs associated with the additional power plants in operation.

Interest expense increased \$11.1 million primarily due to interest costs on plant construction projects, completed in the latter part of 2002 and early 2003, being capitalized during construction compared to expensed after the plants became operational.

## ENERGY MARKETING AND TRANSPORTATION

Our energy marketing and transportation companies produced the following results:

(in thousands)	2004	2003	2002
Revenue*	\$ 662,110	\$ 675,586	\$ 553,688
Operating income	18,181	12,151	17,816
Income from continuing operations	10,222	6,725	12,739

\* All periods presented reflect a net presentation of revenues at our gas marketing subsidiary and a gross presentation of revenues at our crude oil marketing subsidiary in accordance with EITF 02-3 and EITF 99-19.

The following is a summary of energy marketing average daily volumes:

	2004	2003	2002
Natural gas physical sales – MMBtus	1,226,600	897,850	683,500
Natural gas financial sales – Mmbtus	514,500	344,050	404,700
Crude oil – barrels	44,900	58,700	57,200

## 2004 Compared to 2003

Income from continuing operations increased \$3.5 million due to a 40 percent increase in natural gas volumes marketed and a 12 percent increase in natural gas margins received. Earnings were also impacted by increased earnings from oil transportation and marketing due to increased transportation revenues and higher marketing margins. Decreased oil marketing revenues were more than offset by lower cost of sales resulting in the higher marketing margins. These increases were partially offset by unrealized losses recognized through mark-to-market accounting treatment of \$1.1 million in 2004 compared to gains of \$2.6 million in 2003 resulting in a year-over-year decrease of \$3.7 million pre-tax. In addition, 2003 earnings were impacted by the \$3.0 million CFTC settlement.

## 2003 Compared to 2002

Income from continuing operations decreased \$6.0 million due to a \$3.0 million after-tax charge for the settlement with the CFTC and a 10 percent decrease in natural gas margins received, partially offset by a 14 percent increase in natural gas volumes marketed and increased earnings from oil pipelines. In addition, as a result of changing commodity prices, results were impacted by unrealized gains recognized through mark-to-market accounting treatment. Unrealized pre-tax mark-to-market gains were \$2.6 million in 2003 compared to losses of \$0.9 million in 2002, resulting in a year-over-year pre-tax increase of \$3.5 million.

Revenues increased 22 percent from 2002 due to a 3 percent increase in average daily volumes of crude oil marketed at average prices 20 percent higher than 2002. These higher revenues were substantially offset by increased operating expenses for the purchases of crude oil used in marketing.

## OIL AND GAS

Oil and gas operating results were as follows:

(in thousands)	2004	2003	2002
Revenue:	\$ 59,534	\$ 46,977	\$ 26,486
Operating income	19,181	13,258	6,471
Income from continuing operations	12,200	8,400	4,783

The following is a summary of oil and natural gas production:

	2004	2003	2002
Barrels of oil sold	432,400	415,800	452,500
Mcf of natural gas sold	10,000,100	8,348,400	4,682,600
Mcf equivalent sales	12,594,600	10,843,400	7,397,800

The following is a summary of our proved oil and gas reserves and 10 percent estimated present value of future net revenues discounted using a 10 percent rate, at December 31:

	2004	2003	2002
Barrels of oil (in thousands)	5,239	5,389	4,880
MMcf of natural gas	141,983	124,062	28,513
Total in MMcf equivalents	173,417	156,399	57,793
Present value of estimated future net revenues before tax (in thousands)	\$ 394,446	\$ 265,341	\$ 94,165

These reserves are based on reports prepared by Ralph E. Davis Associates, Inc., an independent consulting and engineering firm. 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. Reserves at December 31, 2003 include the March 10, 2003 acquisition of Mallon Resources Corporation. Reserves reflect year end pricing of:

	2004		2003		2002	
	Oil	Gas	Oil	Gas	Oil	Gas
Year-end prices (NYMEX)	\$ 43.45	\$ 6.15	\$ 32.52	\$ 6.19	\$ 31.20	\$ 4.60
Year-end prices (average well-head)	\$ 41.19	\$ 5.55	\$ 30.56	\$ 4.63	\$ 29.24	\$ 3.41

### 2004 Compared to 2003

Income from continuing operations increased \$3.8 million due to a 16 percent increase in volumes sold, primarily related to a full year of production from properties acquired in the March 2003 Mallon Resources acquisition. Average gas and oil prices received in 2004, including the effects of hedging, were \$4.40/Mcf and \$26.24/bbl, respectively, compared to \$3.81/Mcf and \$25.09/bbl in 2003. Total operating expenses increased 20 percent primarily related to increased depletion, production taxes and operating costs associated with the increased production as well as higher corporate cost allocations. In addition, 2004 lease operating expenses per Mcfe sold

(LOE/MCFE) increased 2 percent from \$0.95 per Mcfe to \$0.97 per Mcfe; and depletion per Mcfe sold increased 11 percent from \$0.83 per Mcfe to \$0.92 per Mcfe.

### 2003 Compared to 2002

Income from continuing operations increased \$3.6 million due to a 47 percent increase in volumes sold, primarily related to production from properties acquired in the March 2003 Mallon Resources acquisition. Average gas and oil prices received in 2003, including the effects of hedging, were \$3.81/Mcf and \$25.09/bbl, respectively, compared to \$2.45/Mcf and \$23.01/bbl in 2002. Total operating expenses increased 69 percent primarily related to the additional operations acquired in the Mallon transaction. In addition, 2003 lease operating expenses per Mcfe sold (LOE/MCFE) increased 38 percent from \$0.69 per Mcfe to \$0.95 per Mcfe; and 2003 depletion per Mcfe sold decreased 15 percent from \$0.98 per Mcfe to \$0.83 per Mcfe.

Additional information on our Oil and Gas operations can be found in Note 26 to our Notes to Consolidated Financial Statements.

## COAL MINING

Coal mining results were as follows:

(in thousands)	2004	2003	2002
Revenue:	\$ 31,967	\$ 34,777	\$ 31,335
Operating income	8,454	8,775	9,457
Income from continuing operations	7,463	8,289	8,131

The following is a summary of coal sales quantities:

	2004	2003	2002
Tons of coal sold	4,780,100	4,812,300	4,052,400
Coal reserves (millions of tons)	294	263	273

### 2004 Compared to 2003

Income from continuing operations decreased 10 percent as a result of lower revenues due primarily to scheduled and unscheduled plant outages and an increase in depreciation expense partially offset by lower general and administrative and direct mining costs. Decreased coal tons sold were primarily the result of scheduled and unscheduled plant maintenance outages at the Wyodak plant partially offset by increased sales to the Wygen plant.

In September 2004, the Company reached a tax settlement with the Wyoming Department of Revenue, which resulted in an adjustment to coal billings for the period of fourth quarter 2001 through the year 2003. In 2004, the Company recorded a \$1.7 million reduction in revenues and a corresponding reduction in mineral taxes as a result of the settlement. The Company also recorded an additional \$0.4 million decrease to mineral taxes and \$0.5 million decrease to interest expense in 2004 related to settlement accruals.

## 2003 Compared to 2002

Income from continuing operations increased \$0.2 million due to a 19 percent increase in tons sold, partially offset by a 6 percent decrease in average sales price per ton and an increase in general and administrative and direct mining costs related to the increased production. Increased coal tons sold were the result of sales to our 90 megawatt Wygen power plant that became operational in February 2003 and additional sales through our train load-out facility.

## Retail Services Group

Income from continuing operations for the retail services group decreased \$3.0 million. Earnings from the electric utility segment decreased \$4.9 million, while losses from the communications segment decreased \$1.9 million.

## ELECTRIC UTILITY

(in thousands)	2004	2003	2002
Revenue	\$ 173,745	\$ 171,019	\$ 162,186
Operating expenses	129,936	119,920	104,026
Operating income	\$ 43,809	\$ 51,099	\$ 58,160
Income from continuing operations and net income	\$ 19,209	\$ 24,089	\$ 30,217

The following table provides certain electric utility operating statistics:

	2004	2003	2002
Firm electric sales – MWh	1,959,969	1,994,819	1,966,060
Wholesale off-system – MWh	1,090,827	930,706	979,677

We currently have a winter peak load of 344 megawatts established in December 1998 and a summer peak load of 392 megawatts established in August 2001. We own 435 megawatts of electric utility generating capacity and purchase an additional 50 megawatts under a long-term agreement.

## 2004 Compared to 2003

Electric revenue increased 2 percent in 2004 compared to 2003, primarily due to a 16 percent increase in wholesale off-system sales offset by decreased transmission revenues due to lower approved rates and higher load share of our Open Access Transmission Tariff revenues.

Firm kilowatt-hour sales decreased 2 percent. Residential and commercial sales decreases of 3 percent and 2 percent, respectively, in 2004 accounted for a \$1.7 million decrease in revenue. These decreases were partially offset by a 1 percent increase in industrial sales. The 16 percent increase in wholesale off-system sales accounted for a \$5.9 million increase in revenues.

Revenue per kilowatt-hour sold was 5.5 cents in 2004 compared to 5.6 cents in 2003. The number of customers in the service area increased to 62,259 in 2004 from 61,148 in 2003. Degree days, which is a measure of weather trends, were 11 percent below last year and 9 percent below normal.

Electric utility operating expenses increased \$10.0 million due to a \$5.9 million increase in fuel and purchased power cost, a \$4.5 million increase in certain operations and maintenance costs, including scheduled and unscheduled maintenance costs, increased group insurance and corporate allocations and increased costs associated with the increase in wholesale off-system sales, partially offset by decreased interest expense of \$0.9 million, primarily due to retirement of debt.

The increase in fuel and purchased power cost was due to an \$11.8 million increase in purchased power costs, offset by a \$5.9 million decrease in fuel costs, as prevailing gas prices made it more economical for us to purchase power for our peaking needs and increased off-system sales, rather than generate energy utilizing our gas turbines.

## 2003 Compared to 2002

Electric revenue increased 5 percent in 2003 compared to 2002, primarily due to an 18 percent increase in wholesale off-system sales at an average price that was 24 percent higher than the average price in 2002.

Firm kilowatt-hour sales increased 1 percent. Residential and commercial sales increases of 2 percent and 3 percent, respectively, in 2003 accounted for a \$2.1 million increase in revenue. The 18 percent increase in wholesale off-system sales accounted for a \$5.8 million increase in revenues. These increases were offset by a 4 percent decrease in industrial sales, primarily due to the closing of Homestake Mine, which had been one of our largest customers.

Revenue per kilowatt-hour sold was 5.6 cents in 2003 compared to 5.3 cents in 2002. The number of customers in the service area increased to 61,148 in 2003 from 59,948 in 2002.

Electric utility operating expenses increased \$15.9 million due to a \$10.1 million increase in fuel and purchased power cost, a \$3.7 million increase in certain operations and maintenance costs, including pension expense, a \$1.5 million increase in depreciation expense and a \$2.5 million increase in interest expense due to the full year impact of \$75 million of first mortgage bonds issued in August 2002.

The increase in fuel cost was due to a 77 percent increase in average gas prices for combustion turbine generation facilities and a 19 percent increase in average megawatt-hour purchased power costs.



## COMMUNICATIONS

(in thousands)	2004	2003	2002
Revenue	\$39,586	\$39,763	\$32,677
Operating expenses	41,920	45,004	40,124
Operating loss	\$(2,334)	\$(5,241)	\$(7,447)
Loss from continuing operations and net loss	\$(3,941)	\$(5,880)	\$(7,260)

	2004	2003	2002
Residential customers	23,663	23,878	21,700
Revenue generating units*	56,835	53,568	48,285
Business customers	3,317	3,012**	3,061
Hybrid fiber coaxial cable miles	845	840	818

\* Total Revenue generating units (RGU) equal the total number of services to which residential customers subscribe. Telephone, cable TV and Internet access each represent an RGU.

\*\* In 2003, reported business customers were adjusted for the consolidation of multiple-location business customers, business orders and temporary business access lines.

In September 1998, we formed our broadband communications business to provide facilities-based communications services for Rapid City and the Northern Black Hills of South Dakota. As of December 31, 2004, we had invested approximately \$165 million in state-of-the-art technology that offers local and long distance telephone service, expanded cable television service, Internet access, and high-speed data and video services. We began serving communications customers in late 1999 and market our services to schools, hospitals, cities, economic development groups, and business and residential customers.

## 2004 Compared to 2003

Loss from continuing operations was \$3.9 million in 2004 compared to \$5.9 million in 2003. Results for 2003 and 2002 include our information technology support subsidiary, Daksoft, Inc. Beginning in the first quarter of 2004, Daksoft's focus became corporate information technology support and therefore its results are now included as "corporate" costs. Daksoft's results had an insignificant impact on 2003 net earnings. The improved performance, excluding Daksoft's 2003 results, was due to increased revenues from a larger commercial customer base and increased sales of internet services to residential customers and decreased cost of goods sold and operating costs. These were partially offset by \$0.6 million in sales incentive costs related to higher marketing campaign costs in response to competitive pressures and an increase in allocated corporate costs.

## 2003 Compared to 2002

Loss from continuing operations was \$5.9 million in 2003 compared to \$7.3 million in 2002. The improved performance was due to increased revenues from a larger customer base and an additional \$2.4 million in revenues from a successful directory publication and distribution, partially offset by \$0.5 million in sales incentive costs related to a current marketing campaign in response to competitive pressures. Revenue increases were also partially offset by a \$2.0 million increase in cost of sales and a \$1.8 million increase in depreciation expense. In addition, 2002 results included a \$0.6 million after-tax benefit from the collection of previously reserved amounts.

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## Critical Accounting Policies

We prepare our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. 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.

### 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. Although we believe our estimates of future cash flows are reasonable, different assumptions regarding such cash flows could materially affect our evaluations.

In 2004, an impairment charge of approximately \$0.7 million after-tax was recorded to reduce the carrying value of the Pepperell plant to its estimated fair value, less cost to sell and is included in "Income from discontinued operations, net of taxes" on the 2004 Consolidated Statement of Income.

Our Communications business segment began providing broadband communications services in November 1999 and since that time has not achieved profitability. In each of the last five years, we have evaluated the assets of our Communications business segment for impairment, and in each year we determined, based on our assumptions, that the sum of the anticipated future cash flows (undiscounted and without interest charges) exceeded the carrying value and, therefore, we did not recognize an impairment. The carrying value of the assets tested for impairment was approximately \$110 million at December 31, 2004. Any increases in the anticipated future cash flows would have no impact on the carrying

value of these assets. If our current estimates of future cash flows from the operation of these assets had been 10 percent lower, we still would not have been required to record an impairment charge.

As a result of the 2003 transaction terminating a fifteen year contract with Allegheny Energy Supply Company, LLC, for capacity and energy at the Company's Las Vegas Cogeneration II power plant, we assessed the recoverability of the carrying value of the facility. The carrying value of the assets tested for impairment was \$237.2 million. This assessment resulted in a pre-tax impairment charge of \$117.2 million to write-down the related property, plant and equipment by \$83.1 million, net of accumulated depreciation of \$5.1 million, and intangible assets by \$34.1 million, net of accumulated amortization of \$1.1 million. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by its estimated future discounted cash flows.

In measuring the fair value of the Las Vegas II power plant and the resulting impairment charge, we considered a number of possible cash flow models associated with the various probable operating assumptions and pricing for the capacity and energy of the facility. We then made our best determination of the relative likelihood of the various models in computing a weighted average expected cash flow for the facility. Inclusion of other possible cash flow scenarios and/or different weighting of those that were included could have led to different conclusions about the fair value of the plant. Further, the weighted average cash flow method is sensitive to the discount rate assumption. If we had used a discount rate that was 1 percent higher, the resulting impairment charge would have been approximately \$7.0 million higher. If the discount rate would have been 1 percent lower, the impairment charge would have been approximately \$8.0 million lower.

For long-lived assets with indefinite lives, SFAS 142 requires an annual impairment test. Upon adopting SFAS 142 on January 1, 2002, we completed a transition impairment test in the first quarter of 2002. As a result of this impairment test, we recognized a \$0.8 million after-tax impairment charge related to the goodwill at our discontinued coal marketing operations. This impairment charge is reported as part of "Income from discontinued operations, net of taxes" on the 2002 Consolidated Statement of Income. This impairment charge was offset by income of \$0.9 million, after-tax, from the write-off of negative goodwill at our power generation segment, as required by SFAS 142. This amount is reported as "Change in accounting principles, net of taxes" on the 2002 Consolidated Statement of Income. We completed our 2004 annual goodwill impairment test in the fourth quarter. This test did not result in an additional goodwill impairment.

## FULL COST METHOD OF ACCOUNTING FOR OIL AND GAS ACTIVITIES

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 “ceilings 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 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. Although our net capitalized costs were less than the full cost ceiling at December 31, 2004, we cannot assure you that a write-down in the future will not occur depending on oil and gas prices at that point in time. In addition, we rely on an independent consulting and engineering firm to verify the estimates we use to determine the amount of our proved reserves and those estimates are based on a number of assumptions about variables. We cannot assure you that these assumptions will not differ from actual results.

## RISK MANAGEMENT ACTIVITIES

We enter into derivative instruments, including options, swaps, futures, forwards and other contractual commitments for both non-trading (hedging) and trading purposes. In addition to the information provided below, see Note 2 of our Notes to Consolidated Financial Statements.

### Non-trading (Hedging)

Our typical non-trading (hedging) transactions relate to contracts we enter into at our oil and gas exploration and production subsidiary to fix the price received for anticipated future production; and interest rate swaps we enter into to convert a portion of our variable rate debt to a fixed rate. For these and similar transactions, we utilize hedge accounting treatment under SFAS 133 “Accounting for Derivative Instruments and Hedging Activities” (SFAS 133). As cash flow hedges, these derivative instruments are recorded at fair value on the Consolidated Balance Sheets and the effective portion of the gain or loss is reported in other comprehensive income and the ineffective portion in earnings.

## Energy Trading and Marketing

Our natural gas marketing operations currently fall under the purview of Emerging Issues Task Force 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” (EITF 02-3), SFAS 133, and for contracts entered into before October 25, 2002, in accordance with EITF 98-10. The current fair values of natural gas trading contracts that qualify as derivatives in accordance with SFAS 133 are recorded on the Consolidated Balance Sheets and any period-to-period change in the current fair value of such contracts is recognized in the Consolidated Statements of Income. We have presented the net unrealized and realized gains and losses, whether or not settled financially or physically, from the activities of our natural gas marketing business, in Operating revenues on the Consolidated Statements of Income.

For our crude oil marketing operations, substantially all crude oil contracts historically met the definition of “energy trading activities” under EITF 98-10. Accordingly, all contracts at these operations that originated on or before October 25, 2002 have been accounted for at fair value. With the adoption of EITF 02-3, the contracts at our crude oil marketing operations are no longer recorded at fair value since they do not meet the definition of derivatives or have been exempted from mark-to-market accounting as normal purchase and normal sales contracts. These contracts are accounted for under the accrual method of accounting.

## Valuation

Fair values of derivative instruments and energy trading contracts are based on listed market prices, where possible. If 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.



## Counterparty Credit Risk

We perform ongoing credit evaluations of our customers and adjust credit and tenor limits based upon payment history and the customer's current creditworthiness, as determined by our review of their current financial information. We continuously monitor collections and payments from our customers and 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 established provisions, we cannot be assured that our credit losses will be consistent with our estimates.

## PENSION AND OTHER POSTRETIREMENT BENEFITS

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. Those assumptions, as further described in Note 20 of our Notes to the Consolidated Financial Statements, include, among others, the discount rate, the expected long-term rate of return on plan assets and the rate of increase in compensation levels and healthcare costs. 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.

### Defined Benefit Pension Plan

We account for our defined benefit pension plan in accordance with SFAS 87, "Employers' Accounting for Pensions" (SFAS 87). In accordance with SFAS 87, changes in pension obligations associated with fluctuations in long-term actuarial assumptions may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of the plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. For the years ended December 31, 2004, 2003 and 2002, we recorded non-cash expense related to our pension plans of approximately \$2.6 million, \$3.2 million, and \$0.2 million, respectively.

Our pension plan assets are held in trust and primarily consist of equity securities. Fluctuations in actual equity market returns result in increased or decreased pension costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs.

In selecting an assumed rate of return on plan assets, we consider past performance and economic forecasts for the types of investments held by the plan and weight the returns by applying the assumed rate of return for each asset class to the target allocation for each asset class in the portfolio. The value of our qualified pension plan assets increased \$4.0 million to \$52.8 million for the plan fiscal year ended September 30, 2004. Plan assets earned \$6.3 million in 2004. Plan assets increased \$16.4 million to \$48.8 million as of September 30, 2003, due to our \$10.5 million contribution to the plan and improved performance of the stock market during 2003. Plan assets earned \$8.1 million in 2003. In the recently completed actuarial valuation, for determining our 2005 pension expense, we decreased the assumed rate of return on plan assets from 9.5 percent to 9.0 percent. This change is expected to increase pension costs in 2005 and beyond by approximately \$0.3 million per year. The expected long-term rate of return on plan assets was 9.5 percent, 10 percent and 10.5 percent for the 2004, 2003 and 2002 plan years, respectively.

The 9.5 percent assumed rate of return for the 2004 plan year was determined based on the following estimated long-term investment allocations and asset class returns:

Asset Class	Estimated Allocation	Estimated Return	Weighted Average Return
Equity	90%	10.0%	9.0%
Fixed Income	5	6.0	0.3
Cash	5	4.0	0.2
	100%		9.5%

The Plan's expected long-term rate of return on assets assumption is based upon the weighted average expected long-term rate of returns for individual asset classes. 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 10.0 percent and 10.5 percent for the 2004 and 2003 plan years, respectively. For determining the expected long-term rate of return for equity assets, the Company reviewed 20-, 30-, 40-, and 50-year annual returns for the S&P 500 Index, which were, at December 31, 2004, 13.2 percent, 13.7 percent, 10.4 percent and 10.9 percent respectively. Fund management fees were estimated to be 0.18 percent for S&P 500 Index assets and 0.45 percent for other assets. The expected long-term rate of return on fixed income investments was 6.0 percent; the return was based upon historical returns on intermediate-term treasury bonds of 6.3 percent from 1950 to 2002. The expected long-term rate of return on

cash investments was estimated to be 4.0 percent; expected cash returns were estimated to be 2.0 percent below long-term returns on intermediate-term treasury bonds.

The discount rate we utilize for determining future benefit obligations is based on high grade bond rates. The discount rate was decreased to 6.0 percent for the 2004 pension cost determination from 6.75 percent in 2003. A 0.5 percent decrease in the discount rate would cause annual pension expense to increase by approximately \$0.5 million.

Based on our recently completed plan forecasts, we estimate that we will not be required to make cash contributions to the pension plan during the next five years.

Actual pension expense and contributions required will depend on future investment performance, changes in future discount rates, the level of contributions we make and various other factors related to the populations participating in the pension plan. We will continue to evaluate all of the actuarial assumptions, generally on an annual basis, including the expected long-term rate of return on assets and discount rate, and will adjust the assumptions as necessary.

### Non-qualified Pension Plans

We have various supplemental retirement plans for our outside directors and key executives. The plans are nonqualified defined benefit plans accounted for in accordance with SFAS 87. Expenses recognized under the plans were \$2.3 million in 2004, \$1.7 million in 2003, and \$0.8 million in 2002. The plans are unfunded. The actuarial assumptions used for our non-qualified pension plans are the same as those used for our qualified plan.

### Other Postretirement Benefits

We account for our other postretirement benefit costs in accordance with SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" (SFAS 106). We do not pre-fund our other postretirement benefit plan. Our reported costs of providing other postretirement benefits are dependent upon numerous factors, including healthcare cost trends, and result from actual plan experience and assumptions of future experience. As a result of these factors, significant portions of other postretirement benefit costs recorded in any period do not reflect the actual benefits provided to plan participants. For the years ended December 31, 2004, 2003 and 2002, we recorded other postretirement benefit expense of approximately \$1.5 million, \$1.2 million and \$1.0 million, respectively, in accordance with SFAS 106. Actual payments of benefits to retirees during these periods were approximately \$0.6 million per year.

The following table reflects the sensitivities associated with a change in the assumed healthcare cost trend rate.

Change in Assumption	Impact on December 31, 2004 Accumulated Postretirement Benefit Obligation	Impact on 2004 Service and Interest Cost
Increase 1%	\$ 2,190	\$ 291
Decrease 1%	\$ ( 1,714)	\$ (223)

In selecting assumed healthcare cost trend rates, we consider recent plan experience and various short and long-term cost forecasts for the healthcare industry. Based on these considerations, we changed the healthcare cost trend rate used by the actuaries to determine our other postretirement benefit expense, for 2004 and beyond, to 12 percent in 2004 decreasing gradually to 5 percent in 2011. The healthcare cost trend rate assumption was changed from 11 percent decreasing gradually to 5 percent. These changes increased the future other postretirement benefit expense included on our income statement by approximately \$0.2 million. Our discount rate assumption for postretirement benefits is consistent with that used in the calculation of pension benefits. See the Defined Benefit Pension Plan discussion above regarding our discount rate assumptions.

### 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 realizability 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 were 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.

## Liquidity and Capital Resources

### OVERVIEW

Information about our financial position as of December 31, 2004 and 2003, is presented in the following table:

Financial Position Summary	2004	2003	% Change
Cash and cash equivalents	\$ 64,506	\$ 172,759	(63)%
Short-term debt	40,166	17,659	127%
Long-term debt	733,581	868,459	(16)%
Stockholders' equity	735,765	709,747	4%
Ratios			
Long-term debt ratio	49.9%	55.0%	(9)%
Total debt ratio	51.3%	55.5%	(8)%

Our dividend payout ratio at December 31, 2004 was approximately 70 percent which is higher than levels over the past 5 years. Based on current expectations for 2005, we expect payout ratios for 2005 to be in the range of 64 percent to 69 percent.

In 2005, we expect our beginning cash balance, cash provided from operations, and available credit facilities to be sufficient to meet our normal operating commitments, to pay dividends and to fund a portion of planned capital expenditures. We would expect to fund a significant portion of any additional investment in power generating facilities with long-term debt.

### CASH FLOW ACTIVITIES

#### 2004

In 2004, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common and preferred stock, to pay our scheduled long-term debt maturities and to fund a portion of our property additions. We funded property and investment additions primarily through a combination of cash on hand and operating cash flow.

Cash flows from operations decreased \$34.0 million from the prior year amount, primarily due to the net effect of the 2003 Las Vegas II power plant sales contract termination and related impairment charge partially offset by a \$32.9 million year-over-year increase in deferred taxes, a \$47.8 million increase in the change in operating assets and liabilities and a \$7.0 million increase in depreciation and depletion expense. In 2004, we recognized a substantial increase in our deferred income tax liability due to timing differences associated with mining development and oil exploration costs and accelerated depreciation and other plant related costs.

We had cash outflows from investing activities of \$92.9 million, primarily for property, plant and equipment additions in the normal course of business. We had cash outflows from financing activities of

\$152.1 million, primarily due to the repayment of \$155.0 million of long-term debt, partially offset by a \$24.0 million increase in short-term borrowings and the refinancing of \$18.7 million of pollution control revenue bonds. A detailed description of the significant investing and financing activities follows:

- On January 30, 2004, we prepaid \$45 million of the long-term debt outstanding on the project-level debt at our Fountain Valley facility.
- On May 10, 2004, we repurchased \$25 million of our 6.5 percent senior unsecured notes due 2013.
- On May 13, 2004, we closed on a \$125 million 364-day credit facility, which replaced the \$200 million facility which was due to expire in August 2004. We also amended our \$225 million multi-year facility that expires in August 2006 to conform its compliance calculation to the same calculation as in the new \$125 million facility. We had borrowings of \$24.0 million under these facilities at December 31, 2004. After inclusion of applicable letters of credit, the remaining borrowing capacity under the facilities was \$281.4 million at December 31, 2004.
- On August 31, 2004, we effected a call on Black Hills Power's \$5.9 million, 6.7 percent Pollution Control Revenue Bonds issued through Lawrence County, South Dakota. The bonds had a maturity date of 2010.
- On October 1, 2004, we effected a call and refinanced Black Hills Power's \$18.7 million of Pollution Control Revenue Bonds. \$6.5 million of the bonds had a maturity date of 2014 and \$12.2 million of the bonds had a maturity date of 2024.
- On October 21, 2004, we effected a call on Black Hills Power's entire \$45 million Series AB 8.3 percent First Mortgage bonds. The bonds had a maturity date of 2024.

#### 2003

In 2003, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common and preferred stock, to pay our scheduled long-term debt maturities and to fund a portion of our property additions. We funded property and investment additions primarily through a combination of cash on hand and operating cash flow.

Cash flows from operations decreased \$42.3 million over the prior year amount, primarily due to a \$37.3 million decrease in the year over year change in deferred taxes and a \$140.4 million decrease in the change in operating assets and liabilities, partially offset by the net effect of the Las Vegas II power plant sales contract termination and related impairment charge and a \$16.9 million increase in depreciation and depletion expense. In 2002, we recognized a substantial increase in our deferred income tax liability due to timing differences associated with accelerated depreciation and



expenses related to our large capital investment in power generation assets in 2002 and 2001. In 2003, the change in our deferred tax liability returned to a more normal level. During the third quarter of 2003, we received \$114 million from Allegheny Energy Supply Company, LLC for the termination of a fifteen-year contract for capacity and energy at our Las Vegas II power plant.

We had cash inflows from investing activities of \$77.8 million, which includes approximately \$186 million from the sale of seven hydroelectric power plants located in upstate New York, partially offset by \$104.5 million for property, plant and equipment additions and the acquisition of assets. We had cash outflows from financing activities of \$150.7 million, primarily due to the repayment of \$139.3 million debt, offset by the net proceeds of \$118.0 million from a public offering of 4.6 million shares of common stock and the sale of \$250 million ten-year notes. A detailed description of the significant investing and financing activities follows:

- On April 30, 2003, we completed a public offering of 4.6 million shares of common stock at \$27 per share. Net proceeds were approximately \$118 million after commissions and expenses. The proceeds were used to pay off a \$50 million credit facility due in May 2003 and to repay \$68 million under our 364-day revolving credit facility which expired on August 26, 2003.
- On May 21, 2003, we issued \$250 million 6.5 percent ten-year, senior unsecured notes. Net proceeds from the note offering were approximately \$247 million after the discount, commissions and expenses. The proceeds were used to repay our \$35 million term loan due September 30, 2004, all of our short-term borrowings under our \$195 million, 364-day revolving credit facility and all of our outstanding notes payable under our three-year revolving credit facility which expires on August 24, 2004.
- In August 2003, we closed on a \$225 million multi-year, unsecured revolving credit facility that expires on August 20, 2006. The credit facility replaced the \$195 million facility that expired in August 2003 and supplements the \$200 million facility that expires in August 2004.
- In September 2003, we paid off all of the project-level debt and related interest rate swaps totaling \$91.1 million associated with the seven hydroelectric power plants that were sold.

## DIVIDENDS

Dividends paid on our common stock totaled \$1.24 per share in 2004. This reflected increases approved by our board of directors from \$1.20 per share in 2003 and \$1.16 per share in 2002. All dividends were paid out of current earnings. Our three-year annualized dividend growth rate was 3.5 percent. In January 2005, our board of directors increased the quarterly dividend 3.2 percent to \$0.32 cents per share. If this dividend is maintained during 2005, it will be equivalent to \$1.28 per share, an annual increase of \$0.04 cents 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 PUHCA, restrictions under our credit facilities and our future business prospects.

## SHORT-TERM LIQUIDITY

Our principal sources of short-term liquidity include our cash on hand, our revolving bank facilities and cash provided by operations. As of December 31, 2004 we had approximately \$64.5 million of cash unrestricted for operations and \$350 million of credit through revolving bank facilities. Approximately \$17.7 million of the cash balance at December 31, 2004 was restricted by subsidiary debt agreements that limit our subsidiaries' ability to dividend cash to the parent company. The bank facilities consist of a \$225 million facility due August 20, 2006 and a \$125 million facility due May 12, 2005. These bank facilities can be used to fund our working capital needs, for general corporate purposes, and to provide liquidity for a commercial paper program if implemented. At December 31, 2004, we had \$24 million of bank borrowings outstanding under these facilities. After inclusion of applicable letters of credit, the remaining borrowing capacity under the bank facilities was \$281.4 million at December 31, 2004.

The above bank facilities include financial covenants the most restrictive of which are as follows:

- a consolidated net worth in an amount of not less than the sum of \$550 million and 50 percent of our aggregate consolidated net income beginning April 1, 2004;
- a recourse leverage ratio not to exceed 0.65 to 1.00; and
- a fixed charge coverage ratio of not less than 1.5 to 1.0.

If these covenants are violated and we are unable to negotiate a waiver or amendment thereof, the lender would have the right to declare an event of default, terminate the remaining commitment and accelerate all principal and interest outstanding. As of December 31, 2004, we were in compliance with the above covenants.

Our liquidity position remained ample in 2004, albeit at lower levels than at the end of the prior year. Our reduction in liquidity is reflected in our lower levels of cash on hand and in the reduced level of capacity on our corporate revolving credit line.

Our cash levels at the end of 2004 were \$108.3 million lower than at the end of 2003, due to optional reductions of debt and due to purchases of natural gas inventory.

In 2004, we used a portion of our cash to reduce our aggregate short-term and long-term borrowings by \$112.4 million. In January, 2004 we prepaid \$45 million of long-term debt at our Fountain Valley facility; in May, 2004 we purchased and retired \$25 million of the 6.5 percent senior unsecured notes due in 2013; in August, 2004 we called \$5.9 million of the 6.7 percent Pollution Control Revenue Bonds due in 2010; in October, 2004 we called \$45 million of the Series AB 8.3 percent First Mortgage Bonds and also called and refinanced \$6.5 million of 6.7 percent Pollution Control Revenue Bonds and \$12.2 million of 7.5 percent Pollution Control Revenue Bonds.

In 2004, our gas marketing subsidiary increased levels of natural gas inventory in storage through the purchases of gas which were sold for forward delivery in the first and second quarters of 2005. At year-end 2004, our natural gas inventory was \$63.3 million, compared to \$23.4 million at year-end 2003.

Our consolidated net worth was \$735.8 million at December 31, 2004, which was approximately \$161.7 million in excess of the net worth we are required to maintain under the debt covenant described above. The long-term debt component of our capital structure at December 31,

2004 was 49.9 percent, our total debt leverage ratio was 51.3 percent and our recourse leverage ratio was approximately 46.4 percent.

On January 21, 2005, we purchased CLF&P for approximately \$90 million, including the assumption of \$25 million of CLF&P outstanding debt. We funded the purchase price of this acquisition with existing cash on hand and short-term borrowings on bank credit facilities.

In addition, Enserco Energy, Inc., our gas marketing unit, has a \$150 million uncommitted, discretionary line of credit to provide credit support for the purchase of natural gas. As of December 31, 2004, we had a \$3.0 million guarantee to the lender under this facility. At December 31, 2004, there were outstanding letters of credit issued under the facility of \$91.7 million with no borrowing balances on the facility.

Similarly, Black Hills Energy Resources, Inc. (BHER), our crude oil marketing unit, had a \$25 million uncommitted, discretionary credit facility at December 31, 2004. The facility allows BHER to elect up to \$40 million of available credit via notification to the bank at the beginning of each calendar quarter. This line of credit provides credit support for the purchases of crude oil by BHER. We provided no guarantee to the lender under this facility. At December 31, 2004, BHER had letters of credit outstanding of \$8.9 million and no borrowing balance outstanding on its overdraft line.

Our ability to obtain additional financing, if necessary, will depend upon a number of factors, including our future performance and financial results, and capital market conditions. We cannot assure you that we will be able to raise additional capital on reasonable terms or at all.

The following information is provided to summarize our cash obligations and commercial commitments at December 31, 2004:

(in thousands)	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Contractual Obligations					
Long-term debt <sup>(a)</sup>	\$ 749,747	\$ 16,166	\$ 337,155 <sup>(b)</sup>	\$ 54,387	\$ 342,039
Unconditional purchase obligations <sup>(c)</sup>	230,783	28,429	64,026	35,993	102,335
Operating lease obligations <sup>(d)</sup>	19,205	2,745	4,331	1,881	10,248
Capital leases <sup>(e)</sup>	789	195	334	223	37
Other long-term obligations <sup>(f)</sup>	23,809	-	-	-	23,809
Credit facilities	24,000	24,000	-	-	-
<b>Total contractual cash obligations</b>	<b>\$ 1,048,333</b>	<b>\$ 71,535</b>	<b>\$ 405,846</b>	<b>\$ 92,484</b>	<b>\$ 478,468</b>

(a) In addition the following amounts are required for interest payments on long-term debt over the next five years: \$39.2 million in 2005, \$35.2 million in 2006, \$29.6 million in 2007, \$27.1 million in 2008 and \$26.5 million in 2009.

(b) We expect to refinance maturities on the project financing floating rate debt with project level or corporate level intermediate or long-term debt.

(c) Unconditional purchase obligations include the capacity costs associated with our purchase power agreement with PacifiCorp and certain transmission, communication, gas purchase and gas transportation 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 calculated using existing prices at December 31, 2004. Our transmission obligations are based on filed tariffs as of December 31, 2004. 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, a storage agreement and land leases associated with the Arapahoe, Valmont, Harbor and Ontario power plants.

(e) Represents a lease on computer hardware.

(f) Includes our asset retirement obligations associated with our oil and gas and coal mining segments as discussed in Note 9 to our Notes to Consolidated Financial Statements.

## GUARANTEES

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2004, we had guarantees totaling \$184.7 million in place. Of the \$184.7 million, \$139.3 million was related to guarantees associated with subsidiaries' debt to third parties, which are recorded as liabilities on the Consolidated Balance Sheets, \$20.0 million was related to performance obligations under subsidiary contracts and \$25.4 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 22 of our Notes to Consolidated Financial Statements.

As of December 31, 2004, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2004	Year Expiring
Guarantee payments under the Las Vegas Cogen I Power Purchase and Sales Agreement with Sempra Energy Solutions	\$ 10,000	Upon 5 days written notice
Guarantee of certain obligations under Enserco's credit facility	3,000	2005
Guarantee of obligation of Las Vegas Cogen II under an interconnection and operation agreement	750	2005
Guarantee payments of Black Hills Power under various transactions with Idaho Power Company	500	2005
Guarantee payments of Black Hills Power under various transactions with Southern California Edison Company	750	2005
Guarantee obligations under the Wygen Plant Lease	111,018	2008
Guarantee payment and performance under credit agreements for two combustion turbines	28,213	2010
Guarantee payments of Las Vegas Cogen II to Nevada Power Company under a power purchase agreement	5,000	2013
Indemnification for subsidiary reclamation/surety bonds	25,420	Ongoing
	<b>\$ 184,651</b>	

## CREDIT RATINGS

As of February 28, 2005, our issuer credit rating is "Baa3" by Moody's Investors Service and "BBB-" by Standard & Poor's. In addition, our Black Hills Power's first mortgage bonds are rated "Baa1" and "BBB" by Moody's and Standard & Poor's, respectively. Standard & Poor's downgraded our issuer credit rating to "BBB-" in May 2003. This credit rating downgrade had a minimal effect on our interest rates under our credit agreements. These security ratings are subject to revision and/or withdrawal at any time by the respective rating organizations. None of our current credit agreements contain acceleration triggers. If our issuer credit rating

should drop below investment grade, however, pricing under the credit agreements would be affected, increasing interest expense by approximately \$0.3 million pre-tax based on December 31, 2004 balances.

In addition, as a result of becoming a registered holding company under PUHCA, if our credit ratings drop below investment grade, we would be restricted absent prior SEC approval in the amounts and types of additional investments which we would be allowed to make.

## CAPITAL REQUIREMENTS

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

(in thousands)	2004	2003	2002
Property additions and acquisition costs:			
Wholesale energy	\$ 63,739	\$ 81,271	\$ 248,956
Retail services	21,448	33,605	52,903
Corporate	5,787	1,815	1,332
Common stock dividends	40,210	37,025	31,116
Maturities/redemptions of long-term debt	155,021	139,310	32,527
	<b>\$ 286,205</b>	<b>\$ 293,026</b>	<b>\$ 366,834</b>

Our capital additions for 2004 were \$91.0 million.

The capital expenditures were primarily for maintenance capital and development drilling of oil and gas properties.

Our capital additions for 2003 were \$116.7 million. The capital expenditures were primarily for maintenance capital, development drilling of oil and gas properties and the completion of the construction of an AC-DC-AC converter station for Black Hills Power.

Our capital additions for 2002 were \$303.2 million. The major capital items for the year included the following:

- Acquisition of additional assets and interests in crude oil pipelines and storage facilities.
- Continuation of the construction of our 224 megawatt gas-fired Las Vegas II power plant located near Las Vegas, Nevada, which was placed into service in January 2003.
- Completion of construction of the 50 megawatt combined-cycle expansion at our Arapahoe site in Denver, Colorado, which was placed into service in October 2002.
- Acquisition of an additional 30 percent interest in the Harbor Cogeneration facility.
- Acquisitions of various interests in partnerships in which we previously held a majority interest.
- Completion of construction of the Lange Combustion Turbine for Black Hills Power, which was placed into service in March 2002.



- Construction of an AC-DC-AC converter station for Black Hills Power, which was placed into service in the fourth quarter of 2003.
- Continuation of the construction of our communications fiber optic network.

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

(in thousands)	2005	2006	2007
Wholesale energy*	\$ 52,300	\$ 61,840	\$ 64,710
Retail services**	136,500	92,680	57,710
Corporate	6,530	1,690	1,770
Unspecified development capital	50,000	55,000	96,190
	\$ 245,330	\$ 211,210	\$ 220,380

\* Wholesale energy capital requirements include approximately \$38.7 million, \$43.9 million and \$47.1 million in 2005, 2006 and 2007, respectively, of oil and gas expenditures.

\*\* Retail services regulated utility capital requirements include approximately \$90.0 million for the CLF&P acquisition in 2005 and \$50.0 million and \$18.1 million for the development of a coal-fired plant in 2006 and 2007, respectively.

## Market Risk Disclosures

Our activities in the regulated and unregulated energy sector expose us to a number of risks in the normal operations 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 businesses, our natural length in crude oil and natural gas production, and fuel procurement for our gas fired generation assets; and
- 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.

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 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 Black Hills Corporation Risk Policies and Procedures (BHCRRP). 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 composed of 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 Marketing

We have a natural gas 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 origination efforts focus on supplying and providing electricity generators 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 third party natural gas.

To effectively manage our producer services, end-use origination and wholesale marketing portfolios, we enter into forward physical commodity contracts, financial 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 BHCRRP and further delineated in the gas marketing Commodity Risk Policies and Procedures (CRPP) as approved by the Executive Risk Committee. As a general policy, we permit only limited market risk positions as clearly defined in these policies and procedures.

## MONITORING AND REPORTING MARKET RISK EXPOSURES

Senior management uses a number of quantitative tools to measure, monitor, and limit our exposure to market risk in our natural gas portfolio. We measure and monitor the market risk inherent in the natural gas trading portfolio employing value-at-risk (VaR) analysis and scenario analysis. VaR is a statistical measure that quantifies the probability and magnitude of potential future losses related to open contract positions. We use scenario analysis to test the impact of extreme moves in both specific delivery points and overall commodity prices on our portfolio value. We also monitor and limit

our market risk by establishing limits on the nominal size of positions based on type of trade, location, and duration.

VaR is a statistical measure used to quantify the potential loss in fair value of the trading portfolio over a particular time, with a specified likelihood of occurrence, due to adverse market price changes. We use an external VaR model from a third party vendor and utilize independent commodity pricing data. The modeling of VaR involves a number of assumptions and approximations. Inputs for the VaR calculation include commodity prices, positions, instrument valuations, and variance-covariance matrices. While we believe that our assumptions and approximations are reasonable, there is currently no uniform methodology or best practice for calculating VaR in the energy sector.

We calculate VaR on a daily basis to determine the potential three-day favorable and unfavorable changes to the market value of our portfolio. The VaR is computed utilizing Monte Carlo simulation based on correlation matrices for price movements over a specified period (generally ranging from one to three months) to simulate forward price curves in the natural gas markets to estimate the “worst case” outcomes on the existing portfolio value. The VaR computations utilize a 99 percent loss level for a three day holding period with a 95 percent confidence level. This calculation means that there is a one in one hundred (1 in 100) statistical chance that the portfolio value will fall below the expected maximum potential reduction in portfolio value at least as large as the reported VaR over a three day period, provided that no mitigation actions are taken during these three days.

At year-end 2004, we were completing the implementation of an enhanced trade capture system and due to technical constraints, must estimate our VaR. During this system implementation, risk management activities focused upon scrutinizing positions, their changes in daily mark-to-market and other non-statistical risk management techniques. Our estimate of the three-day, 99 percent loss level VaR is approximately \$1.7 million.

Actual commodity price volatility can result in portfolio values worse than predicted using the VaR model. The VaR methodology assumes a normal distribution of price changes; thus, if the actual distribution is not normal, the VaR may understate actual results. VaR is used to estimate the risk of the entire gas marketing portfolio. For locations that have insufficient daily trading activity, VaR may not accurately estimate risk due to limited price information. Therefore, stress tests are employed, in addition to VaR, to further measure risk when market price information may prove insufficient. VaR is effective in estimating risk exposures in markets in which there are not sudden fundamental

changes or shifts in market conditions. An inherent limitation of VaR is that past changes in assumed market risk factors may not produce accurate predictions of future market risk. VaR should be evaluated in light of this and the methodology’s other limitations.

The contract or notional amounts, terms and mark-to-market values of our natural gas marketing and derivative commodity instruments at December 31, 2004 and 2003, are set forth in Note 2 of our Notes to Consolidated Financial Statements.

The following table provides a reconciliation of the activity in our energy trading portfolio that has been recorded at fair value under a mark-to-market method of accounting during the year ended December 31, 2004 (in thousands):

Total fair value of natural gas marketing marked-to-market at December 31, 2003	\$ 1,222 <sup>(a)</sup>
Net cash settled during the year on positions that existed at December 31, 2003	(3,454)
Unrealized gain on new positions entered during the year and still existing at December 31, 2004	(73)
Realized gain on positions that existed at December 31, 2003 and were settled during year	1,983
Unrealized loss on positions that existed at December 31, 2003 and still exist at December 31, 2004.	(608)
Total fair value of natural gas marketing positions marked-to-market at December 31, 2004	\$ (930) <sup>(a)</sup>

(a) The fair value of positions marked-to-market consists of derivative assets/liabilities and natural gas inventory that has been designated as a hedged item and marked-to-market as part of a fair value hedge, as follows (in thousands):

	December 31, 2004	December 31, 2003
Net derivative assets/(liabilities)	\$ 8,082	\$ (408)
Fair value adjustment recorded in material, supplies and fuel	(9,012)	1,630
	\$ (930)	\$ 1,222

On January 1, 2003, the Company adopted EITF Issue No. 02-3. The adoption of EITF 02-3 resulted in certain energy trading activities no longer being accounted for at fair value, therefore, the above reconciliation does not present a complete picture of our overall portfolio of trading activities and our expected cash flows from those operations. EITF 98-10 was superseded by EITF 02-3 and allowed a broad interpretation of what constituted “trading activity” and hence what would be marked-to-market. EITF 02-3 took a much narrower view of what “trading activity” should be marked-to-market, limiting mark-to-market treatment primarily to only those contracts that meet the definition of a derivative under SFAS 133. At our natural gas 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 very 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 our inventory, transportation or storage positions to market. The result is that while a significant majority of our natural gas 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 should be expected given these accounting requirements.

At December 31, 2004, we had a mark to fair value unrealized loss of \$0.9 million for our natural gas marketing activities. Of this amount, \$(1.2) million was current and \$0.3 million was non-current. The source of fair value measurements were as follows (in thousands):

Source of Fair Value	Maturities		Total Fair Value
	2005	2006 and Thereafter	
Actively quoted (i.e., exchange-traded) prices	\$ 784	\$ -	\$ 784
Prices provided by other external sources	(1,994)	280	(1,714)
Modeled	-	-	-
<b>Total</b>	<b>\$ (1,210)</b>	<b>\$ 280</b>	<b>\$ (930)</b>

The following table presents a reconciliation of our natural gas marketing positions recorded at fair value under GAAP to a non-GAAP measure of the fair value of our natural gas forward book wherein all forward trading positions are marked-to-market. The approach used in determining the non-GAAP measure is consistent with our previous accounting methods under EITF 98-10.

Fair value of our natural gas marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	\$ (930)
Increase/(decrease) in fair value of inventory, storage and transportation positions that are part of our forward trading book, but that are not marked-to-market under GAAP	9,650
<b>Fair value of all forward positions (Non-GAAP)</b>	<b>\$ 8,720</b>

## ACTIVITIES OTHER THAN TRADING

### Crude Oil Marketing

We have a crude oil marketing and transportation services company operating predominately in Texas, Oklahoma, and Louisiana. We specialize in providing independent producers with marketing and transportation services to market their crude oil production to end-use markets. Our main objective is to provide value in the supply chain by acting as the producer's "marketing arm" for wellhead purchasing, scheduling services, imbalance management and transportation management.

To provide these services, we execute physical crude oil purchase contracts with producers and resell into various crude oil markets. Through these transactions, we effectively lock in a marketing fee equal to the difference between the sales price and the purchase price, less transportation costs. The crude oil marketing portfolio is essentially hedged whereby market risk, basis risk and quality differentials are mitigated or eliminated. We do not speculate with the crude oil marketing portfolio with the intent to generate profits from short-term market differences. Any accepted risk will be from small differences in contract terms, index risk, or credit risk. Any risk that we identify will be managed and mitigated within the guidelines stipulated in the BHCRRP.

The contract or notional amounts, terms and mark-to-market values of our crude oil contracts at December 31, 2004 and 2003 are set forth in Note 2 of our Notes to Consolidated Financial Statements.



## Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. These 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 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.

Any hedging strategies are conducted with an enterprise wide perspective. As more fully defined in the next section, we have some fuel procurement risk within our gas-fired generation business. Therefore, hedging in the oil and gas segment considers any natural hedge offsets in the power generation segment. In certain cases, we do not hedge forecasted natural gas production when we have offsetting market risk in our fuel requirements in the power generation segment. In other words, exploration and production’s natural length is used to offset generation’s short position.

The contract or notional amounts, terms and fair values of our contracts used to hedge portions of our crude oil and natural gas production at December 31, 2004 and 2003 are set forth in Note 2 of our Notes to Consolidated Financial Statements.

To mitigate commodity price risk and preserve cash flows, we use over-the-counter swaps and options.

The Company has entered into agreements to hedge a portion of its estimated 2005 and 2006 natural gas and crude oil production. The hedge agreements in place at December 31, 2004 are as follows:

### NATURAL GAS

Location	Term	Volume (mmbtu/day)	Price
San Juan El Paso	01/05 – 03/05	2,000	\$ 4.80
San Juan El Paso	01/05 – 03/05	2,500	\$ 5.63
San Juan El Paso	01/05 – 03/05	2,500	\$ 7.15
San Juan El Paso	01/05 – 03/05	2,500	\$ 7.24
San Juan El Paso	01/05 – 03/05	2,500	\$ 8.00
San Juan El Paso	04/05 – 10/05	2,500	\$ 5.30
San Juan El Paso	04/05 – 10/05	5,000	\$ 5.40
San Juan El Paso	04/05 – 10/05	2,500	\$ 6.04
San Juan El Paso	11/05 – 03/06	2,500	\$ 7.08
CIG	01/05 – 03/05	2,500	\$ 6.01

### CRUDE OIL

Location	Term	Volume (barrels/month)	Price
NYMEX	Calendar 2005	10,000	\$ 27.90
NYMEX	Calendar 2005	10,000	\$ 34.08
NYMEX	Calendar 2006	10,000	\$ 41.00

## Power Generation

We have a portfolio of gas-fired generation assets located throughout several Western states. The output from most of these generation assets are sold under long-term tolling contracts with third parties whereby any commodity price risk is transferred to the third party. However, we do have some gas-fired generation assets under long-term contracts and a few merchant plants that do possess market risk for fuel purchases.

It is our policy that fuel risk, to the extent possible, be hedged. Since we are “long” natural gas in our exploration and production segment, we look at our enterprise wide natural gas market risk when hedging at the subsidiary level. Therefore, we may attempt to hedge only enterprise wide “long” or “short” positions.

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 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, 2004, we had \$113.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 1.75 years. Further details of the swap agreements are set forth in Note 2 of our Notes to Consolidated Financial Statements.

On December 31, 2004 and 2003, our interest rate swaps and related balances were as follows (in thousands):

(in thousands)		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)
December 31, 2004	Notional							
Swaps on project financing	\$113,000	4.22%	1.75	\$ 60	\$ -	\$ 1,226	\$ 200	\$ (1,366)
December 31, 2003								
Swaps on project financing	\$113,000	4.48%	2.75	\$ 256	\$ -	\$ 3,247	\$ 1,931	\$ (4,922)
Swaps on corporate debt	25,000	5.28%	0.25	\$ -	-	169	-	(169)
	\$138,000			\$ 256	\$ -	\$ 3,416	\$ 1,931	\$ (5,091)

We anticipate a portion of unrealized losses recorded in accumulated other comprehensive income will be realized as increased interest expense in 2005. Based on December 31, 2004 market interest rates, \$1.2 million will be realized as additional interest expense during 2005. Estimated and realized amounts will likely change during 2005 as market interest rates change.

At December 31, 2004, we had \$366.6 million of outstanding, variable-rate debt of which \$253.6 million was not offset with interest rate swap transactions that effectively convert the debt to a fixed rate. A 100 basis point increase in interest rates would cause interest expense to increase \$2.5 million.

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

	2005	2006	2007	2008	2009	Thereafter	Total
Cash equivalents							
Fixed rate	\$64,506	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 64,506
Long-term debt							
Fixed rate	\$2,854	\$ 2,865	\$ 2,049	\$ 2,062	\$ 2,078	\$ 371,280	\$ 383,188
Average interest rate	8.5%	8.5%	9.6%	9.6%	9.6%	7.3%	7.4%
Variable rate <sup>(a)</sup>	\$13,312	\$197,546	\$113,468	\$19,165	\$ 2,000	\$ 21,068	\$ 366,559
Average interest rate	3.9%	3.5%	3.6%	3.0%	4.0%	3.9%	3.5%
Total long-term debt	\$16,166	\$200,411	\$115,517	\$21,227	\$ 4,078	\$ 392,348	\$ 749,747
Average interest rate	4.7%	3.5%	3.7%	3.6%	6.9%	7.1%	5.5%

(a) Approximately 31 percent of the variable rate long-term debt has been hedged with interest rate swaps moving the floating rates to fixed rates with an average interest rate of 4.22 percent.

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## CREDIT RISK

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We have adopted the Black Hills Corporation Credit Policy (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 composed of senior executives meets on a regular basis to review the Company's credit activities and to monitor compliance with the policies adopted by the Company.

For our energy marketing, production, and generation activities, we attempt 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 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 assure you 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 the end of the year, our credit exposure (exclusive of retail customers of our regulated utility and communications segment) was concentrated with investment grade companies. Approximately 74 percent of our credit exposure was with investment grade companies. For the 26 percent credit exposure with non-investment grade rated counterparties, approximately 91 percent of this exposure was supported through letters of credit, prepayments, parental guarantees and asset liens.

## FOREIGN EXCHANGE CONTRACTS

Our gas 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, 2004, we had outstanding forward exchange contracts to sell approximately \$38.0 million Canadian dollars and at December 31, 2003, had no forward exchange contracts.

At December 31, 2004 and 2003, we also had outstanding forward exchange contracts to purchase approximately \$10.8 million and \$3.0 million Canadian dollars, respectively. These contracts had a fair value of \$(1.0) million and \$0.1 million at December 31, 2004 and 2003, respectively, and have been recorded as Derivative Assets/Liabilities on the accompanying Consolidated Balance Sheets. All forward exchange contracts outstanding at December 31, 2004 settle by April 2005.

## **New Accounting Pronouncements**

See Note 1 of our Notes to Consolidated Financial Statements for information on new accounting standards adopted in 2004 or pending adoption.

## **Safe Harbor for Forward-Looking Information**

This Annual Report includes "forward-looking statements" as defined by the Securities and Exchange Commission (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 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 which 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 the Risk Factors set forth in this report and the following:

- The amount and timing of capital deployment in new investment opportunities or for the repurchase of debt or stock;
- The volumes of our production from oil and gas development 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;
- The extent of our success in connecting natural gas supplies to gathering, processing and pipeline systems;
- Our ability to successfully integrate CLF&P into our operations;
- Our compliance with orders of the SEC under PUHCA related to our financing and investment authority, and related to transactions and cost allocation among our affiliated companies;



- 
- Our ability to remedy any deficiencies that may be identified in the review of our internal controls;
  - The timing and extent of changes in energy-related and commodity prices, interest rates, energy and commodity supply or volume, the cost of transportation of commodities, and demand for our services, all of which can affect our earnings, liquidity position and the underlying value of our assets;
  - General economic and political conditions, including tax rates or policies and inflation rates;
  - Our use of derivative financial instruments to hedge commodity, currency exchange rate and interest rate risks;
  - The creditworthiness of counterparties to trading and other transactions, and defaults on amounts due from counterparties;
  - The amount of collateral required to be posted from time to time in our transactions;
  - Changes in or compliance with laws and regulations, particularly those relating to taxation, safety and protection of the environment;
  - Changes in state laws or regulations that could cause us to curtail our independent power production;
  - Weather and other natural phenomena;
  - Industry and market changes, including the impact of consolidations and changes in competition;

- 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;
- Capital market conditions, which may affect our ability to raise capital on favorable terms;
- Price risk due to marketable securities held as investments in benefit plans;
- Obtaining adequate cost recovery for our retail operations through regulatory proceedings; and
- Other factors discussed from time to time in our other filings with the SEC.

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 our forward-looking statements, whether as a result of new information, future events or otherwise.

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## ***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.

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, 2004, 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, 2004.

Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein.

BLACK HILLS CORPORATION

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## **Report of Independent Registered Public Accounting Firm**

Board of Directors and Stockholders  
Black Hills Corporation

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

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

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, management's assessment that the Corporation maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in the COSO Framework. Also in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in the COSO Framework.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2004, of the Corporation, and our report dated March 10, 2005, expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph relating to the adoption of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, and Emerging Issues Task Force Issue 02-3, Accounting for Contracts Involving Energy Trading and Risk Management Activities, effective January 1, 2003; Financial Accounting Standards Board Interpretation No. 46 (Revised), Consolidation of Variable Interest Entities, effective December 31, 2003; and Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets, effective January 1, 2002.

DELOITTE & TOUCHE LLP  
Minneapolis, Minnesota  
March 10, 2005



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## **Report of Independent Registered Public Accounting Firm**

Board of Directors and Stockholders  
Black Hills Corporation

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the “Corporation”) as of December 31, 2004 and 2003, and the related consolidated statements of income, common stockholders’ equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Corporation’s management. Our responsibility is to express an opinion on these consolidated 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, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Corporation’s internal control over financial reporting as of December 31, 2004, 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 10, 2005, expressed an unqualified opinion on management’s assessment of the effectiveness of the Corporation’s internal control over financial reporting and an unqualified opinion on the effectiveness of the Corporation’s internal control over financial reporting.

As discussed in Note 9 and Note 2, respectively, to the consolidated financial statements, effective January 1, 2003, the Corporation adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, and Emerging Issues Task Force Issue 02-3, Accounting for Contracts Involving Energy Trading and Risk Management Activities. As discussed in Note 6 to the consolidated financial statements, effective December 31, 2003, the Corporation adopted Financial Accounting Standards Board Interpretation No. 46 (Revised), Consolidation of Variable Interest Entities. As discussed in Note 1 to the consolidated financial statements, effective January 1, 2002, the Corporation adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets.

DELOITTE & TOUCHE LLP  
Minneapolis, Minnesota  
March 10, 2005

**BLACK HILLS CORPORATION**  
**Consolidated Statements of Income**

(in thousands, except per share amounts)

Years ended December 31,	2004	2003	2002
Revenues:			
Operating revenues	\$ 1,121,701	\$ 1,136,050	\$ 908,477
Contract termination revenue	-	114,000	-
	1,121,701	1,250,050	908,477
Operating expenses:			
Fuel and purchased power	703,261	718,450	580,973
Operations and maintenance	99,371	99,335	68,257
Administrative and general	68,859	73,548	64,673
Depreciation, depletion and amortization	87,833	80,791	63,865
Taxes, other than income taxes	28,458	29,551	17,993
Impairment of long-lived assets	-	117,207	-
	987,782	1,118,882	795,761
Operating income	133,919	131,168	112,716
Other income (expense):			
Interest expense	(51,842)	(52,579)	(33,564)
Interest income	1,758	1,076	609
Other expense	(491)	(539)	(554)
Other income	1,181	1,209	3,264
	(49,394)	(50,833)	(30,245)
Income from continuing operations before minority interest, income taxes and change in accounting principle	84,525	80,335	82,471
Equity in earnings of unconsolidated subsidiaries	(386)	5,747	4,588
Minority interest	(186)	-	(2,277)
Income taxes	(26,704)	(29,601)	(26,644)
Income from continuing operations before changes in accounting principles	57,249	56,481	58,138
Income from discontinued operations, net of income taxes	724	9,936	2,418
Changes in accounting principles, net of income taxes	-	(5,195)	896
Net income	57,973	61,222	61,452
Preferred stock dividends	(321)	(258)	(223)
Net income available for common stock	\$ 57,652	\$ 60,964	\$ 61,229
Earnings per share of common stock:			
Basic-			
Continuing operations	\$ 1.76	\$ 1.84	\$ 2.16
Discontinued operations	0.02	0.33	0.09
Changes in accounting principles	-	(0.17)	0.03
Total	\$ 1.78	\$ 2.00	\$ 2.28
Diluted-			
Continuing operations	\$ 1.74	\$ 1.82	\$ 2.14
Discontinued operations	0.02	0.32	0.09
Changes in accounting principles	-	(0.17)	0.03
Total	\$ 1.76	\$ 1.97	\$ 2.26
Weighted average common shares outstanding:			
Basic	32,387	30,496	26,803
Diluted	32,912	31,015	27,167

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

# BLACK HILLS CORPORATION

## Consolidated Balance Sheets

(in thousands, except share amounts)

At December 31,

	2004	2003
<b>ASSETS</b>		
Current assets:		
Cash and cash equivalents	\$ 64,506	\$ 172,759
Restricted cash	3,069	1,350
Accounts receivable (net of allowance for doubtful accounts of \$4,698 and \$7,345, respectively)	256,505	201,976
Materials, supplies and fuel	89,732	44,895
Derivative assets	47,977	26,804
Deferred income taxes	4,237	4,256
Prepaid income taxes	3,978	18,940
Notes receivable	239	554
Other current assets	7,005	8,321
Assets of discontinued operations	3,059	4,575
	480,307	484,430
Investments	24,436	26,847
Property, plant and equipment	1,971,119	1,882,545
Less accumulated depreciation and depletion	(525,387)	(440,274)
	1,445,732	1,442,271
Other assets:		
Goodwill	30,144	30,144
Intangible assets, net	36,750	40,070
Derivative assets	593	1,002
Other	38,201	38,488
	105,688	109,704
	\$ 2,056,163	\$ 2,063,252
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>		
Current liabilities:		
Accounts payable	\$ 196,619	\$ 162,706
Accrued liabilities	69,306	66,618
Derivative liabilities	43,206	32,967
Notes payable	24,000	-
Current maturities of long-term debt	16,166	17,659
Accrued income taxes	7,799	5,752
Liabilities of discontinued operations	651	3,444
	357,747	289,146
Long-term debt, net of current maturities	733,581	868,459
Deferred credits and other liabilities:		
Deferred income taxes	159,623	125,040
Derivative liabilities	206	3,247
Other	64,406	62,924
	224,235	191,211
Minority interest	4,835	4,689
Commitments and contingencies (Notes 8, 16, 20, 21 and 22)		
Stockholders' equity:		
Preferred stock – no par Series 2000-A; 21,500 shares authorized; issued and outstanding: 6,839 and 7,771 respectively	7,167	8,143
Common stock equity –		
Common stock \$1 par value; 100,000,000 shares authorized; issued: 32,595,285 shares in 2004 and 32,447,765 shares in 2003	32,595	32,448
Additional paid-in capital	384,439	379,271
Retained earnings	322,009	304,567
Treasury stock at cost – 117,567 shares in 2004 and 150,048 shares in 2003	(2,838)	(3,560)
Accumulated other comprehensive loss	(7,607)	(11,122)
	728,598	701,604
Total stockholders' equity	735,765	709,747
	\$ 2,056,163	\$ 2,063,252

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



**BLACK HILLS CORPORATION**  
**Consolidated Statements of Cash Flows**

(in thousands)			
Years ended December 31,	2004	2003	2002
Operating activities:			
Net income available for common	\$ 57,652	\$ 60,964	\$ 61,229
Adjustments to reconcile net income available for common to net cash provided by operating activities –			
Income from discontinued operations	(724)	(9,936)	(2,418)
Depreciation, depletion and amortization	87,833	80,791	63,865
Impairment of long-lived assets	-	117,207	-
Issuance of treasury stock for operating expense	1,030	361	2,252
Change in provision for valuation allowances	(2,598)	3,363	(2,935)
Net change in derivative assets and liabilities	(8,101)	(317)	(2,086)
Deferred income taxes	29,186	(3,743)	33,597
Undistributed earnings in associated companies	3,762	(3,874)	(2,972)
Minority interest	186	-	2,277
Accounting changes	-	5,195	(896)
Change in operating assets and liabilities-			
Accounts receivable and other current assets	(75,620)	(75,673)	(74,806)
Accounts payable and other current liabilities	34,061	(6,863)	128,209
Other operating activities	10,015	3,206	7,670
	136,682	170,681	212,986
Investing activities:			
Property, plant and equipment additions	(90,974)	(90,353)	(232,347)
Proceeds from sale of assets	-	185,926	-
Payment for acquisition of net assets, net of cash acquired	-	-	(23,229)
Payment for acquisition of minority interest	-	(9,000)	(13,800)
Increase in notes receivable – Mallon Resources	-	(5,164)	(33,815)
Other investing activities	(1,892)	(3,566)	(5,300)
	(92,866)	77,843	(308,491)
Financing activities:			
Dividends paid on common stock	(40,210)	(37,025)	(31,116)
Common stock issued	4,031	123,073	5,084
Increase (decrease) in short-term borrowings, net	24,000	(340,500)	(19,500)
Long-term debt – issuance	18,650	252,000	223,135
Long-term debt – repayments	(155,021)	(139,310)	(25,069)
Other financing activities	(3,519)	(8,924)	(8,312)
	(152,069)	(150,686)	144,222
Increase (decrease) in cash and cash equivalents	(108,253)	97,838	48,717
Cash and cash equivalents:			
Beginning of year	172,759	74,921	26,204
End of year	\$ 64,506	\$ 172,759	\$ 74,921
Supplemental disclosure of cash flow information:			
Cash paid during the period for-			
Interest (net of amount capitalized)	\$ 49,546	\$ 51,452	\$ 41,404
Income taxes paid (refunded)	\$ (21,927)	\$ 58,660	\$(31,353)
Non-cash net assets acquired through issuance of common and preferred stock (Note 21)	\$ -	\$ 6,231	\$ 3,826
Property, plant and equipment acquired with accrued liabilities and the issuance of long-term debt	\$ -	\$ 6,951	\$ -
Non-cash net assets of Mallon Resources, acquired through issuance of common stock and decrease in notes receivable (Note 24)	\$ -	\$ 51,153	\$ -

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**

(in thousands)	Common Stock		Additional Paid-In Capital	Retained Earnings	Treasury Stock		Accumulated Other Comprehensive Income (loss)	Total
	Shares	Amount			Shares	Amount		
Balance at December 31, 2001	26,891	\$ 26,891	\$ 241,454	\$ 250,515	239	\$ (5,503)	\$ (3,742)	\$ 509,615
Comprehensive Income:								
Net income	-	-	-	61,452	-	-	-	61,452
Other comprehensive loss, net of tax (see Note 18)	-	-	-	-	-	-	(17,450)	(17,450)
Total comprehensive income	-	-	-	61,452	-	-	(17,450)	44,002
Dividends on preferred stock	-	-	-	(223)	-	-	-	(223)
Dividends on common stock	-	-	-	(31,116)	-	-	-	(31,116)
Issuance of common stock	211	211	4,993	-	-	-	-	5,204
Treasury stock issued, net	-	-	550	-	(70)	1,582	-	2,132
Balance at December 31, 2002	27,102	27,102	246,997	280,628	169	(3,921)	(21,192)	529,614
Comprehensive Income:								
Net income	-	-	-	61,222	-	-	-	61,222
Other comprehensive income, net of tax (see Note 18)	-	-	-	-	-	-	10,070	10,070
Total comprehensive income	-	-	-	61,222	-	-	10,070	71,292
Dividends on preferred stock	-	-	-	(258)	-	-	-	(258)
Dividends on common stock	-	-	-	(37,025)	-	-	-	(37,025)
Issuance of common stock	5,346	5,346	130,484	-	-	-	-	135,830
Treasury stock issued, net	-	-	1,790	-	(19)	361	-	2,151
Balance at December 31, 2003	32,448	32,448	379,271	304,567	150	(3,560)	(11,122)	701,604
Comprehensive Income:								
Net income	-	-	-	57,973	-	-	-	57,973
Other comprehensive income, Net of tax (see Note 18)	-	-	-	-	-	-	3,515	3,515
Total comprehensive income	-	-	-	57,973	-	-	3,515	61,488
Dividends on preferred stock	-	-	-	(321)	-	-	-	(321)
Dividends on common stock	-	-	-	(40,210)	-	-	-	(40,210)
Issuance of common stock	147	147	4,860	-	-	-	-	5,007
Treasury stock issued, net	-	-	308	-	(32)	722	-	1,030
Balance at December 31, 2004	32,595	\$ 32,595	\$ 384,439	\$ 322,009	118	\$ (2,838)	\$ (7,607)	\$ 728,598

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

**Notes to Consolidated Financial Statements**  
**December 31, 2004, 2003 and 2002**

**1 Business Description and Summary  
of Significant Accounting Policies**

**BUSINESS DESCRIPTION**

Black Hills Corporation is a registered public utility holding company and with its subsidiaries operates in two primary operating groups: non-regulated wholesale energy and retail services. The Company operates its wholesale energy businesses through its direct and indirect subsidiaries: Wyodak Resources related to coal, Black Hills Exploration and Production related to oil and natural gas production, Enserco Energy related to natural gas marketing and Black Hills Energy Resources related to crude oil marketing and transportation, and Black Hills Generation and its subsidiaries and Black Hills Wyoming related to independent power activities, all aggregated for reporting purposes as Black Hills Energy. Retail services include public utility electric operations through its subsidiary, Black Hills Power, Inc.; and communications operations through its subsidiaries Black Hills Fiber Systems and Black Hills FiberCom L.L.C. In addition, on January 21, 2005, the Company expanded its retail services with the acquisition of Cheyenne Light, Fuel and Power (see Note 25). For further descriptions of the Company's business segments, see Note 23.

In 2004, the Company sold its subsidiary, Landrica Development Corp., which held land and coal enhancement facilities. In 2003, the Company sold its hydroelectric power plants located in Upstate New York. The non-strategic assets were sold effective September 30, 2003. Amounts related to Landrica and the hydroelectric power plants are included in Discontinued operations on the accompanying Consolidated Financial Statements.

**USE OF ESTIMATES**

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities 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, inventory obsolescence, realization of market value of derivatives due to commodity risk, intangible asset valuations and useful lives, long-lived asset values and

useful lives, proved oil and gas reserve volumes, employee benefit plans, environmental accruals and contingencies. Actual results could differ from those estimates.

**PRINCIPLES OF CONSOLIDATION**

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly owned and majority-owned subsidiaries. In addition, as of December 31, 2003, the Company consolidated Wygen Funding, Limited Partnership, a variable interest entity in which the Company is the primary beneficiary as defined by Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities Revised" (FIN 46-R). Generally, the Company uses equity accounting for investments of which it owns between 20 and 50 percent and investments in partnerships under 20 percent if the Company exercises significant influence.

All significant intercompany balances and transactions have been eliminated in consolidation except for revenues and expenses associated with intercompany fuel sales in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Total intercompany fuel sales not eliminated were \$9.6 million, \$10.3 million and \$10.5 million in 2004, 2003 and 2002, respectively.

The Company's consolidated statements of income include operating activity of acquired companies beginning with their acquisition date.

The Company uses the proportionate consolidation method to account for its working interests in oil and gas properties and for its ownership in the jointly owned Black Hills Power transmission tie, the Wyodak power plant and the Black Hills Exploration and Production gas processing plant as discussed in Note 5.

**MINORITY INTEREST IN SUBSIDIARIES**

Minority interest in the accompanying Consolidated Statements of Income represents the share of income or loss of certain consolidated subsidiaries attributable to the minority shareholders of those subsidiaries. The minority interest in the accompanying Consolidated Balance Sheets reflect the amount of the underlying net assets of those certain consolidated subsidiaries attributable to the minority shareholders in those subsidiaries.

Earnings attributable to minority ownership in certain subsidiaries are generally shown on the accompanying consolidated statement of income on a pre-tax basis as the subsidiaries with minority investors are typically



limited liability companies or partnerships which pay no tax at the corporate or partnership level.

## REGULATORY ACCOUNTING

The Company's subsidiary, Black Hills Power, 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 Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's non-regulated businesses.

Black Hills Power follows the provisions of SFAS 71, and its financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating Black Hills Power. A 50-year depreciable life for the Neil Simpson II plant is used for financial reporting purposes. If Black Hills Power were not a regulated utility following SFAS 71, a 35 to 40 year life would likely be more appropriate, which would increase depreciation expense by \$0.6 - \$1.1 million per year. If rate recovery of generation-related costs becomes unlikely or uncertain, due to competition or regulatory action, these accounting standards may no longer apply to Black Hills Power's generation operations. In the event Black Hills Power determines that it no longer meets the criteria for following SFAS 71, the accounting impact to the Company could be an extraordinary non-cash charge to operations of an amount that could be material. Criteria that give rise to the discontinuance of SFAS 71 include increasing competition that could restrict Black Hills Power's ability to establish prices to recover specific costs and a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews these criteria to ensure that the continuing application of SFAS 71 is appropriate.

At December 31, 2004 and 2003, the Company had regulatory assets of \$7.2 million and \$4.6 million and regulatory liabilities of \$6.0 million and \$6.3 million, respectively. Regulatory assets are primarily recorded for the probable future revenue to recover future income taxes related to the deferred tax liability for the equity component of allowance for funds used during construction of utility assets and for unamortized losses on reacquired debt. Regulatory liabilities include the probable future decrease in rate revenues related to a decrease in deferred tax liabilities for prior reductions in statutory federal income tax rates and also the cost of removal for utility plant, recovered through the Company's electric utility rates. The regulatory assets are included in Other assets and the regulatory liabilities are included in Other deferred credits and other liabilities on the Consolidated Balance Sheets.

## CASH EQUIVALENTS

The Company considers 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, 2004, the following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets:

(in thousands)		
Major Classification	2004	2003
Materials and supplies	\$22,661	\$18,920
Fuel for generation	2,211	1,581
Gas and oil held by energy marketing	64,860	24,394
Total materials, supplies and fuel	\$89,732	\$44,895

"Materials and supplies" and "Fuel for generation" are stated at the lower of cost or market. Generally, cost for these classifications is determined on a weighted-average cost methodology.

"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 inventory is stated at the lower of cost or market on a weighted-average cost basis. To the extent that inventory has been designated as the underlying hedged item in a "fair value" hedge transaction, those volumes are stated at market value using published spot industry quotations.

## DERIVATIVES AND HEDGING ACTIVITIES

The Company accounts for its derivative and hedging activities in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). SFAS 133 requires that every derivative instrument be recorded in 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, must be recognized currently in earnings.

#### CURRENCY ADJUSTMENTS

The Company's natural gas marketing subsidiary, Enserco, engages in business transactions in Canada and accordingly, has 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 Statement of Income as incurred.

#### DEFERRED FINANCING COSTS

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

#### PROPERTY, PLANT AND EQUIPMENT

Additions to property, plant and equipment are recorded at cost when placed in service. Included in the cost of regulated construction projects is an allowance for funds used during construction (AFUDC) which represents the approximate composite cost of borrowed funds and a return on capital used to finance the project. The AFUDC was computed at an annual composite rate of 9.8 percent during 2004 and 2003 and 9.1 percent during 2002, respectively. In addition, the Company capitalizes interest, when applicable, on certain non-regulated construction projects. The amount of AFUDC and interest capitalized was \$0.2 million, \$0.4 million and \$11.5 million in 2004, 2003 and 2002, 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. 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. Repairs and maintenance of property are charged to operations as incurred.

Depreciation provisions for property, plant and equipment are computed on a straight-line or componentization basis. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method on volumes produced and estimated reserves.

#### OIL AND GAS OPERATIONS

The Company accounts for its oil and gas activities under the full cost method. Under the full cost method, costs related to acquisition, exploration and development drilling activities are capitalized. These costs are amortized using a units-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.

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 percent, 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 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 market price changes eliminate or reduce the indicated write-down. Given the volatility of oil and gas prices, the Company's 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 a write-down of oil and gas properties could occur in the future. No "ceiling test" write-downs were recorded during 2004, 2003 or 2002.

#### GOODWILL AND INTANGIBLE ASSETS

In June 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS 142). Under SFAS 142, goodwill and intangible assets with indefinite lives are no longer amortized but the carrying values are reviewed annually (or more frequently if impairment indicators arise) for impairment. Intangible assets with a defined life will continue to be amortized over their useful lives (but with no maximum life). The amortization provisions of SFAS 142 apply to goodwill and intangible assets acquired after June 30, 2001. With respect to goodwill and intangible assets acquired prior to July 1, 2001, the Company was required to adopt SFAS 142 effective January 1, 2002. The cumulative effect adjustment recognized upon adoption of SFAS 142 was \$0.1 million (after-tax), which had only a nominal impact on earnings per share. The adjustment consisted of income from the after-tax write-off of negative goodwill from prior acquisitions in the power generation segment of \$0.9 million, offset by a \$0.8 million after-tax write-off for the impairment of goodwill related to the discontinued coal marketing operations (see Note 19). The goodwill impairment was a result of changes in the criteria for the measurement of impairments from an undiscounted to a discounted cash flow method. If the

carrying value exceeds the fair value, an impairment loss will be recognized. A discounted cash flow approach was used to determine fair value of the Company's businesses for the purposes of testing for impairment.

The substantial majority of the Company's goodwill and intangible assets are contained within the Power Generation segment. Changes to goodwill and intangible assets during the years ended December 31, 2004 and 2003 are as follows (in thousands):

	Goodwill	Amortized Other Intangible Assets
Balance at December 31, 2002, net of accumulated amortization	\$ 23,913	\$ 78,089
Additions	6,231	62
Impairment losses	-	(34,094)
Amortization expense	-	(3,987)
Balance at December 31, 2003, net of accumulated amortization	30,144	40,070
Amortization expense	-	(3,320)
Balance at December 31, 2004, net of accumulated amortization	\$ 30,144	\$ 36,750

Intangible assets primarily relate to site development fees and above-market long-term contracts within the Power Generation segment and are amortized using a straight-line method using estimated useful lives ranging from 5 to 40 years. Intangible assets totaled \$58.5 million, with accumulated amortization of \$21.7 million at December 31, 2004 and \$58.5 million, with accumulated amortization of \$18.4 million at December 31, 2003. Amortization expense for intangible assets was \$3.3 million, \$4.0 million and \$4.2 million in 2004, 2003 and 2002, respectively. Amortization expense for existing intangible assets for the next five years is expected to be approximately \$3.3 million a year.

During the third quarter of 2003, the Company wrote off intangible assets of \$34.1 million, net of accumulated amortization of \$1.1 million, related to the impairment of the Las Vegas II plant. The impairment charge is a result of a contract termination and subsequent impairment of the Las Vegas II plant (see Notes 13 and 14).

Goodwill additions during the year ended December 31, 2003 were from contingent consideration related to the July 7, 2000 acquisition of Indeck Capital Inc. (see Note 11).

#### IMPAIRMENT OF LONG-LIVED ASSETS

The Company periodically evaluates whether events and circumstances have occurred which may affect the estimated useful life or the recoverability of the remaining balance of its long-lived assets. If such events or circumstances were to indicate that the carrying amount of these assets was not recoverable, the Company 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, the Company would recognize an impairment loss. In 2004, a \$1.1 million pre-tax impairment was recorded to reduce the carrying value of the Company's Pepperell power plant. This charge is reported in discontinued operations. In 2003, a \$117.2 million pre-tax impairment was recorded to reduce the carrying value of the Las Vegas II facility. In 2002, a \$0.8 million pre-tax impairment was recorded for intangible assets in the discontinued coal marketing operations.

#### 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.

The Company uses 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. 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. The Company classifies deferred tax assets and liabilities into current and non-current amounts based on the classification of the related assets and liabilities.

#### 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. In addition, energy marketing businesses have historically used the mark-to-market method of accounting. Under that method, all 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 Emerging Issues Task Force (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" (EITF 02-3), all energy marketing contracts entered into after October 25, 2002 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 No. 91-6, "Revenue Recognition of Long-Term Power Sales Contracts" (EITF 91-6), or in accordance with SFAS No. 13, "Accounting for Leases," (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. Under SFAS 13, revenue is generally levelized over the life of the agreement. Revenues from one-year advertising contracts in telephone directories published by our Communications segment are recognized on the publication date with cash received prior to publication deferred until it is recognized. For its Investment in Associated Companies (see Note 3), which are involved in power generation, the Company uses the equity method to recognize as earnings its pro rata share of the net income or loss of the associated company.

The Company presents its operating revenues from energy marketing operations in accordance with the guidance provided in EITF 02-3 and EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" (EITF 99-19). Accordingly, gains and losses (realized and unrealized) on transactions at our natural gas marketing operations are presented on a net basis in operating revenues, whether or not settled physically. Settled amounts on contracts at our crude oil marketing operations are reported on a gross basis as they are not held for "trading purposes" as defined by EITF 02-3 and EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and not 'held for trading purposes' as defined by Issue No. 02-3."

## EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share from continuing operations is computed by dividing "Income from continuing operations before change in accounting principle" less preferred 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):

	2004		2003		2002	
	Income	Average Shares	Income	Average Shares	Income	Average Shares
Income from continuing operations	\$57,249		\$56,481		\$58,138	
Less: preferred stock dividends	(321)		(258)		(223)	
Basic – Income from continuing operations	56,928	32,387	56,223	30,496	57,915	26,803
Dilutive effect of:						
Stock options	-	96	-	102	-	91
Convertible preferred stock	321	195	258	222	223	148
Estimated contingent shares issuable for prior acquisition	-	159	-	158	-	88
Others	-	75	-	37	-	37
Diluted – Income from continuing operations	\$57,249	32,912	\$56,481	31,015	\$58,138	27,167

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):

	2004	2003	2002
Options to purchase common stock	484	334	381
Restricted stock	-	21	34
	484	355	415



## STOCK-BASED COMPENSATION

At December 31, 2004, the Company has three stock-based employee compensation plans under which it can issue stock options to its employees, which are described more fully in Note 10. The Company accounts for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25), and related Interpretations. No stock-based employee compensation cost is reflected in net income, as all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS 123), to stock-based employee compensation as of December 31 (in thousands, except per share amounts):

	2004	2003	2002
Net income available for common stock, as reported	\$ 57,652	\$ 60,964	\$ 61,229
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(665)	(794)	(990)
Pro forma net income	\$ 56,987	\$ 60,170	\$ 60,239
Earnings per share:			
As reported – Basic			
Continuing operations	\$ 1.76	\$ 1.84	\$ 2.16
Discontinued operations	0.02	0.33	0.09
Change in accounting principles	-	(0.17)	0.03
Total	\$ 1.78	\$ 2.00	\$ 2.28
Diluted			
Continuing operations	\$ 1.74	\$ 1.82	\$ 2.14
Discontinued operations	0.02	0.32	0.09
Change in accounting principles	-	(0.17)	0.03
Total	\$ 1.76	\$ 1.97	\$ 2.26
Pro forma – Basic			
Continuing operations	\$ 1.74	\$ 1.81	\$ 2.13
Discontinued operations	0.02	0.33	0.09
Change in accounting principles	-	(0.17)	0.03
Total	\$ 1.76	\$ 1.97	\$ 2.25
Diluted			
Continuing operations	\$ 1.72	\$ 1.80	\$ 2.11
Discontinued operations	0.02	0.32	0.09
Change in accounting principles	-	(0.17)	0.03
Total	\$ 1.74	\$ 1.95	\$ 2.23

## RECLASSIFICATIONS

Certain 2003 and 2002 amounts in the consolidated financial statements have been reclassified to conform to the 2004 presentation. These reclassifications had no effect on the Company's stockholders' equity or results of operations, as previously reported.

## RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

### FSP 106-2

In May 2004, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP 106-2), which provides guidance on the accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (2003 Medicare Act) for employers that sponsor postretirement healthcare plans that provide prescription drug benefits. If the Plan is deemed actuarially equivalent to the prescription drug benefit under the 2003 Medicare Act, the sponsor of the Plan could be eligible for a federal subsidy. FSP 106-2 supersedes FSP 106-1 that was issued in January 2004 under the same title. FSP 106-2 is effective for the first interim period beginning after June 15, 2004. The Company provides prescription drug benefits to certain eligible employees. The actuarial measurement of the accumulated postretirement benefit obligation and net periodic postretirement benefit cost does not include the effects of the 2003 Medicare Act as it is believed the Plan is not actuarially equivalent (see Note 20).

### FSP FAS 141-1 and FAS 142-1

In April 2004, the FASB issued FSP FAS 141-1 and FAS 142-1, "Interaction of FASB Statements No. 141, *Business Combinations*, and No. 142, *Goodwill and Other Intangible Assets*, and EITF Issue No. 04-2, *Whether Mineral Rights Are Tangible or Intangible Assets*." The FSP amends SFAS 141 and SFAS 142 to conform with the EITF consensus in EITF 04-2 that mineral rights, as defined by EITF 04-2, are tangible assets. When the Company adopted SFAS 142 on January 1, 2002, the amounts related to mineral rights were already classified as tangible assets and continue to be classified in "Property, plant and equipment" on the accompanying Consolidated Balance Sheets. The adoption of FSP FAS 141-1 and FAS 142-1 had no effect on the Company's consolidated financial position, results of operations or cash flows.

## RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

### SFAS No. 123 (Revised 2004)

In December 2004, the FASB issued SFAS No. 123 (Revised 2004) "Share Based Payment" (SFAS 123 (Revised 2004)). SFAS 123 (Revised 2004) requires the measurement and recognition of the cost of employee services received in exchange for an award of equity instruments, based on the grant-date fair value of the award. The cost is to be recognized over the requisite service period. The effective date of SFAS 123 (Revised 2004) is the first interim period beginning after June 15, 2005. The Company currently accounts for its employee equity compensation stock option plans under the provisions of APB No. 25 and no stock-based employee compensation cost is reflected in net income (see Note 1, Stock-Based Compensation and Note 10 Common Stock). The effect of adoption of SFAS 123 (Revised 2004) will be to recognize compensation expense for the fair value of the stock options granted at the grant date. Total stock-based employee compensation expense, net of related tax effects would have been \$0.7 million in 2004, \$0.8 million in 2003 and \$1.0 million in 2002 had the Company applied the fair value recognition provisions of SFAS 123 during those periods.

## 2 Risk Management Activities

The Company's activities in the regulated and unregulated energy sector expose it to a number of risks in the normal operations of its businesses. Depending on the activity, the Company is exposed to varying degrees of market risk and counterparty risk. The Company has 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. The Company is exposed to the following market risks:

- commodity price risk associated with its marketing businesses, its natural length in crude oil and natural gas production, and fuel procurement for its gas fired generation assets;
- 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.

The Company's 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 markets.

To manage and mitigate these identified risks, the Company has adopted the Black Hills Corporation Risk Policies and Procedures (BHCRRP). These policies have been approved by the Company's Executive Risk Committee and reviewed by the Board of Directors. These policies include governance, control infrastructure, authorized commodities and trading instruments, prohibited activities, employee conduct, etc. The Company has an Executive Risk Committee composed of senior level executives that meets on a regular basis to review the Company's business and credit activities and to ensure that these activities are conducted within the authorized policies.

## TRADING ACTIVITIES

### Natural Gas Marketing

To effectively manage our marketing portfolios, the Company enters into forward physical commodity contracts, financial instruments including over-the-counter swaps and options, transportation agreements and forward foreign exchange contracts.

Gas marketing business activities are conducted within the parameters as defined and allowed in the BHCRRP and further delineated in the gas marketing Commodity Risk Policies and Procedures (CRPP) as approved by the Executive Risk Committee. As a general policy, only limited market risk positions are permitted, as clearly defined in these policies and procedures. Therefore, a significant majority of the Company's gas marketing positions are fully hedged. The Company attempts to balance its portfolio in terms of volume and timing of performance and delivery obligations.

The Company's natural gas marketing operations fall under the purview of EITF 02-3, SFAS 133, and for contracts entered into before October 25, 2002, in accordance with EITF 98-10. As such, all natural gas contracts entered into on or before October 25, 2002 and contracts entered after that date that meet the definition of a derivative as defined by SFAS 133, are accounted for under mark-to-market accounting. 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.

For the years ended December 31, 2004 and 2003, contracts and other activities at the Company's natural gas marketing operations are accounted for under the provisions of EITF 02-3 and SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). As such, all of the contracts and other activities at the Company's natural gas marketing operations that meet the definition of a derivative under SFAS 133 are accounted for at fair value. EITF 02-3, adopted on January 1, 2003, precludes mark-to-market accounting for energy trading contracts that are not derivatives pursuant to SFAS 133. The prior authoritative accounting guidance applied was EITF Issue 98-10 "Accounting for Contracts Involving Energy Trading and Risk Management Activities" (EITF 98-10), which allowed a broad interpretation of what constituted "trading activity" and hence what would be marked-to-market. EITF 02-3 took a much narrower view of what "trading activity" should be marked-to-market, limiting mark-to-market treatment primarily to only those contracts that meet the definition of a derivative under SFAS 133. At the Company's natural gas marketing operations, management often employs strategies that include derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of the Company's producer services, end-use origination and wholesale marketing groups. Except in limited circumstances when the Company is able to designate transportation, storage or inventory positions as part of a fair value hedge, SFAS 133 generally does not allow the Company to mark inventory, transportation or storage positions to market. The result is that while a significant majority of the Company's natural gas marketing positions are economically hedged, the Company is required to mark some parts of its overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of its economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions should be expected given these accounting requirements.

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

(thousands of MMBtu's)	2004		2003	
	Notional Amounts	Latest expiration (months)	Notional Amounts	Latest expiration (months)
Natural gas basis swaps purchased	24,942	15	13,028	12
Natural gas basis swaps sold	27,145	15	12,691	12
Natural gas fixed-for-float swaps purchased	27,274	15	19,645	18
Natural gas fixed-for-float swaps sold	32,206	12	21,752	18
Natural gas physical purchases	64,799	15	50,757	27
Natural gas physical sales	95,996	58	44,066	27
Natural gas options purchased	9,643	33	-	-
Natural gas options sold	9,613	33	-	-
(thousands of U.S. dollars)				
Canadian dollars purchased	\$10,800	1	\$3,000	1
Canadian dollars sold	\$38,000	4	\$ -	-

Derivatives and certain natural gas marketing activities were marked to fair value on December 31, 2004 and 2003, 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, 2004 and 2003 are as follows (in thousands):

	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Unrealized Gain (loss)
December 31, 2004	\$46,177	\$ 286	\$38,375	\$ 6	\$ 8,082
December 31, 2003	\$26,376	\$1,002	\$26,495	\$1,291	\$ (408)

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in a "fair value" hedge transaction. These volumes are stated at market value using published spot industry quotations. Market adjustments are recorded in inventory on the Balance Sheet and unrealized gain/loss on the Statement of Income. As of December 31, 2004 and 2003, the market adjustments recorded in inventory were \$(9.0) million and \$1.6 million, respectively.

## ACTIVITIES OTHER THAN TRADING

### Crude Oil Marketing

The Company's crude oil marketing operations executes physical crude oil purchase contracts with producers and resells into various crude oil markets. Through these transactions, the Company effectively locks in a marketing fee equal to the difference between the sales price and the purchase price, less transportation costs. The crude oil marketing portfolio is essentially hedged whereby market risk, basis risk and quality differentials are mitigated or eliminated. The Company does not speculate with the crude oil marketing portfolio with the intent to generate profits from short-term market differences. Any accepted risk will be from small differences in contract terms, index risk, or credit risk. Any risk that the Company identifies will be managed and mitigated within the guidelines stipulated in the BHCRRP.

The Company's crude oil marketing operations had historically fallen under the purview of EITF 98-10 and as such, all crude oil contracts entered into on or before October 25, 2002, had been accounted for under mark-to-market accounting. The net gains or losses have been

recorded as Operating revenues in the accompanying Consolidated Statements of Income. With the adoption of EITF 02-3, the contracts entered into at the Company's crude oil marketing operations either do not meet the definition of derivatives under SFAS 133 or have been exempted from mark-to-market accounting as normal purchase or normal sales contracts as allowed by SFAS 133. Accordingly, none of these contracts entered into after October 25, 2002 are marked-to-market.

The contract or notional amounts and terms of our crude oil contracts at December 31, are set forth below:

	2004		2003	
	Notional	Maximum	Notional	Maximum
(thousands of barrels)	Amounts	Term	Amounts	Term
		in Years		in Years
Crude oil purchased	1,669	1.0	2,688	0.5
Crude oil sold	1,651	1.0	2,253	0.5

As of December 31, 2004 and 2003, all of the Company's crude oil marketing contracts are accounted for under the accrual method of accounting.



## Oil and Gas Exploration and Production

The Company produces natural gas and crude oil through its exploration and production activities. These natural “long” positions, or unhedged open positions, introduce commodity price risk and variability in its cash flows. The Company employs risk management methods to mitigate this commodity price risk and preserve cash flows. The Company has adopted guidelines covering hedging for its natural gas and crude oil production. These guidelines have been approved by the Company’s Executive Risk Committee, and are routinely reviewed by its Board of Directors.

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

At December 31, 2004 and 2003, the Company had a portfolio of swaps to hedge portions of its crude oil and natural gas production. These transactions were previously identified 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, 2004 and 2003, 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, 2004 and 2003 the Company had the following swaps and related balances (in thousands):

		Maximum Terms in Years	Current Assets	Non- current Assets	Current Liabilities	Non- current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Earnings (Loss)
December 31, 2004	Notional							
Crude oil swaps	360,000	1.00	\$ -	\$ 152	\$ 3,112	\$ -	\$ (2,886)	\$ (74)
Natural gas swaps	3,810,000	0.50	1,710	155	493	-	1,372	-
			\$ 1,710	\$ 307	\$ 3,605	\$ -	\$ (1,514)	\$ (74)
December 31, 2003								
Crude oil swaps	360,000	1.00	\$ -	\$ -	\$ 1,445	\$ -	\$ (1,384)	\$ (61)
Natural gas swaps	4,830,000	1.25	172	-	1,611	25	(1,462)	(2)
			\$ 172	\$ -	\$ 3,056	\$ 25	\$ (2,846)	\$ (63)

\* Crude in bbls, gas in MMBtus.

Most of the Company’s crude oil and natural gas hedges are highly effective, resulting in very little earnings impact prior to realization. The Company estimates a portion of the unrealized earnings gains or losses currently recorded in accumulated other comprehensive income will be realized in earnings during 2005. Based on December 31, 2004 market prices, a \$1.8 million loss will be realized and reported in earnings during 2005. These estimated realized losses for 2005 were calculated using December 31, 2004 market prices. Estimated and actual realized losses will likely change during 2005 as market prices change.

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## Power Generation

The Company has a portfolio of natural gas fueled generation assets located throughout several western states. Most of these generation assets are locked into long-term tolling contracts with third parties whereby any commodity price risk is transferred to the third party. However, we do have some natural gas fueled generation assets under long-term contracts and a few merchant plants that do possess market risk for fuel purchases.

It is the Company's policy that fuel risk, to the extent possible, be hedged. Since the Company is "long" natural gas in its exploration and production company,

the Company looks at its enterprise wide natural gas market risk when hedging at the subsidiary level. Therefore, the Company attempts to hedge only enterprise wide "long" or "short" positions.

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, the Company restricts wholesale off-system sales to amounts by which the Company's anticipated generating capabilities exceed its anticipated load requirements plus a required reserve margin.

## FINANCING ACTIVITIES

The Company engages in activities to manage risks associated with changes in interest rates. The Company has entered into floating-to-fixed interest rate swap agreements to reduce its exposure to interest rate fluctuations associated with its floating rate debt obligations. At December 31, 2004, these hedges met effectiveness testing criteria and retained their cash flow hedge status. At December 31, 2004, the Company had \$113.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 1.75 years and a fair value of \$(1.4) million. These hedges are substantially effective and any ineffectiveness was immaterial.

On December 31, 2004 and 2003 the Company's 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 Income (Loss)
December 31, 2004								
Swaps on project financing	\$113,000	4.22%	1.75	\$ 60	\$ -	\$ 1,226	\$ 200	\$ (1,366)
December 31, 2003								
Swaps on project financing	\$113,000	4.48%	2.75	\$ 256	\$ -	\$ 3,247	\$ 1,931	\$ (4,922)
Swaps on corporate debt	25,000	5.28%	0.25	-	-	169	-	(169)
	\$138,000			\$ 256	\$ -	\$ 3,416	\$ 1,931	\$ (5,091)

The Company anticipates a portion of unrealized losses recorded in accumulated other comprehensive income will be realized as increased interest expense in 2005. Based on December 31, 2004 market interest rates, \$1.2 million will be realized as additional interest expense during 2005. Estimated and realized amounts will likely change during 2005 as market interest rates change.

At December 31, 2004, the Company had \$366.6 million of outstanding, floating-rate debt of which \$253.6 million was not offset with interest rate swap transactions that effectively convert the debt to a fixed rate. A 100 basis point increase in interest rates would cause annual interest expense to increase \$2.5 million.

During 2003 and 2002, the Company entered into treasury locks to hedge the risk of interest rate movement between the hedge date and the expected pricing date for a portion of certain of the Company's debt offerings during those periods. These swaps terminated and cash-settled resulting in a \$5.8 million loss. These swaps were designated as cash flow hedges, and accordingly, the resulting loss will remain in "Accumulated other comprehensive loss" on the Consolidated Balance Sheet and be amortized into earnings as additional interest expense over the life of the related long-term financings.

## FOREIGN EXCHANGE CONTRACTS

The Company's gas marketing subsidiary conducts its business in the United States as well as western Canada. Transactions in Canada are generally transacted in Canadian dollars and create exchange rate risk for the Company. To mitigate this risk, the Company enters into forward currency exchange contracts to offset earning volatility from changes in exchange rates between the Canadian and United States dollars. At December 31, 2004 and 2003, the Company had outstanding forward exchange contracts to sell approximately \$38.0 million and \$0 Canadian dollars, respectively. At December 31, 2004 and 2003, the Company also had outstanding forward exchange contracts to purchase approximately \$10.8 million and \$3.0 million Canadian dollars, respectively. These contracts had a fair value of \$(1.0) million and \$0.1 million at December 31, 2004 and 2003, respectively, and have been recorded as Derivative Assets/Liabilities on the accompanying Consolidated Balance Sheets. All forward exchange contracts outstanding at December 31, 2004 settle by April 2005.

## CREDIT RISK

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. The Company adopted the Black Hills Corporation Credit Policy (BHCCP) that establishes guidelines, controls, and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, the Company has an Executive Credit Committee composed of senior executives that meets on a regular basis to review the Company's credit activities and monitor compliance with the policies adopted by the Company.

For energy marketing, production, and generation activities, the Company mitigates its credit exposure by attempting to conduct its business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements, and securing credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and asset security agreements.

The Company performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. The Company maintains a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

At the end of the year, the Company's credit exposure (exclusive of retail customers of our regulated utility and

communications segment) was concentrated with investment grade companies. Approximately 74 percent of the credit exposure was with investment grade companies. For the 26 percent credit exposure with non-investment grade rated counterparties, approximately 91 percent of this exposure was supported through letters of credit, prepayments, parental guarantees and asset liens.

## 3 Investments in Associated Companies

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

- A 12.6 percent, 6.9 percent and 5.3 percent interest in Energy Investors Fund, L.P., Energy Investors Fund II, L.P., and Project Finance Fund III, L.P., respectively, which in turn have investments in numerous electric generating facilities in the United States and elsewhere. The Company has a carrying amount in the investment of \$10.3 million and \$13.8 million at December 31, 2004 and 2003, respectively, which includes \$1.9 million that represents the cost of the investment over the underlying net assets of the funds. As of, and for the year ended December 31, 2004, the funds had assets of \$130.5 million, liabilities of \$0.3 million and net income of \$6.0 million. As of, and for the year ended December 31, 2003, the funds had assets of \$163.8 million, liabilities of \$0.4 million and net income of \$5.0 million.

Included in "Equity in earnings of unconsolidated subsidiaries" on the 2004, 2003 and 2002 Consolidated Statements of Income is approximately \$0.3 million, \$3.1 million and \$0, respectively, related to the application of the provisions of the AICPA Audit and Accounting Guide, "Audits of Investment Companies," by the funds in which the Company invests. This guidance among other things requires investments held by investment companies to be stated at fair value.

- A 50 percent interest in two natural gas-fired cogeneration facilities located in Rupert and Glenns Ferry, Idaho. The Company's carrying amount in the investment is \$3.6 million and \$3.7 million as of December 31, 2004 and 2003, respectively, which includes \$0.6 million that represents the cost of the investment over the value of the underlying net assets of the projects. As of, and for the year ended December 31, 2004, these projects had assets of \$19.8 million, liabilities of \$12.3 million and net loss of \$0.3 million. As of, and for the year ended December 31, 2003, these projects had assets of \$23.9 million, liabilities of \$16.0 million and net income of \$0.8 million.



## 4 Property, Plant and Equipment

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

<b>Regulated</b>			
	2004	2003	Lives (in years)
Electric plant:			
Production	\$ 320,483	\$ 316,544	25-58
Transmission*	83,488	122,640	35-50
Distribution	198,583	150,748	20-40
General	30,658	29,857	7-40
Total electric plant	633,212	619,789	
Less accumulated depreciation and amortization	232,401	212,041	
Electric plant net of accumulated depreciation and amortization	400,811	407,748	
Construction work in progress	4,066	3,060	
Net electric plant	\$ 404,877	\$ 410,808	

\* As part of the Common Use Transmission Open-Access Transmission Tariff FERC filing that was originally made in 2003, the majority of 69KV lines and substation costs were reclassified from Transmission to Distribution assets.

<b>Non-regulated</b>						
	2004					
	Property, Plant and Equipment	Less Accumulated Depreciation	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Lives (in years)
Coal mining	\$ 72,846	\$ 36,922	\$ 35,924	\$ 521	\$ 36,445	3-39
Oil & gas	259,695	81,165	178,530	-	178,530	3-40
Energy marketing and transportation	27,517	3,344	24,173	942	25,115	3-40
Power generation	791,275	112,124	679,151	1,110	680,261	3-40
Communications	160,775	56,547	104,228	4,576	108,804	3-31.5
Other	6,633	2,884	3,749	7,951	11,700	5-7
	\$ 1,318,741	\$ 292,986	\$ 1,025,755	\$ 15,100	\$ 1,040,855	

	2003					
	Property, Plant and Equipment	Less Accumulated Depreciation	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Lives (in years)
Coal mining	\$ 65,932	\$ 34,555	\$ 31,377	\$ 6,353	\$ 37,730	3-39
Oil & gas	205,137	65,756	139,381	-	139,381	3-40
Energy marketing and transportation	27,456	2,190	25,266	382	25,648	3-40
Power generation	786,930	81,095	705,835	4,754	710,589	3-40
Communications	159,534	43,930	115,604	-	115,604	3-31.5
Other	3,075	707	2,368	143	2,511	5-7
	\$ 1,248,064	\$ 228,233	\$ 1,019,831	\$ 11,632	\$ 1,031,463	

## 5 *Jointly Owned Facilities*

The Company's subsidiary, Black Hills Power (BHP), owns a 20 percent interest and PacifiCorp owns an 80 percent interest in the Wyodak Plant (Plant), a 362 megawatt coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp is the operator of the Plant. BHP receives 20 percent of the Plant's capacity and is committed to pay 20 percent of its additions, replacements and operating and maintenance expenses. As of December 31, 2004, BHP's investment in the Plant included \$73.4 million in electric plant and \$34.5 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. BHP's share of direct expenses of the Plant was \$6.0 million, \$5.8 million and \$5.5 million for the years ended December 31, 2004, 2003 and 2002, respectively, and is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. As discussed in Note 21, the Company's coal mining subsidiary, Wyodak Resources, supplies 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 Wyodak Resources' 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. Wyodak Resources' sales to the Plant were \$16.2 million, \$18.7 million and \$19.0 million for the years ended December 31, 2004, 2003 and 2002, respectively.

BHP also owns a 35 percent interest and Basin Electric Power Cooperative owns a 65 percent interest in the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie placed into service in the fourth quarter of 2003. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides the Company with access to both the Western Electricity Coordinating Council (WECC) region and the Mid-Continent Area Power Pool, or "MAPP" region. The total transfer capacity of the tie is 400 megawatts – 200 megawatts West to East and 200 megawatts from East to West. BHP is committed to pay 35 percent of the additions, replacements and operating and maintenance expenses. For the twelve months ended December 31, 2004, BHP's share of direct expenses was \$0.1 million. As of December 31, 2004, BHP's investment in the transmission tie was \$19.7 million.

The Company, through its subsidiary Black Hills Exploration and Production (BHEP), owns a 44.7 percent non-operating interest in the Newcastle Gas Plant (Gas Plant); a gas processing facility that gathers and processes approximately 3,000 MCF/day of gas, primarily from

the Finn-Shurley Field in Wyoming. The Company receives its proportionate share of the Gas Plant's net revenues and is committed to pay its proportionate share of additions, replacements and operating and maintenance expenses. As of December 31, 2004, the Company's investment in the Gas Plant included \$4.0 million in plant and equipment and \$3.5 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. The Company's share of revenues of the Gas Plant was \$2.5 million, \$1.7 million and \$1.1 million for the years ended December 31, 2004, 2003 and 2002, respectively. The Company's share of direct expenses for the Gas Plant were \$0.3 million, \$0.2 million and \$0.3 million for the years ended December 31, 2004, 2003 and 2002, respectively. These items are included in the corresponding categories of operating revenues and expenses in the accompanying Consolidated Statements of Income.

## 6 *Variable Interest Entity*

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). In December 2003, the FASB issued FIN No. 46 (Revised) (FIN 46-R) to address certain FIN 46 implementation issues. The Company's subsidiary, Black Hills Wyoming, has an agreement with Wygen Funding, Limited Partnership, an unrelated variable interest entity (VIE) to lease the Wygen plant. Under the accounting interpretation, as amended, the Company consolidated the VIE effective December 31, 2003. The effect of consolidating the VIE into the Company's Consolidated Balance Sheet at December 31, 2003 was an increase in total assets of \$129.0 million, of which \$121.5 million, net of accumulated depreciation of \$3.0 million, is included in Property, plant and equipment and an increase in long-term debt in the amount of \$128.3 million.

Prior to the December 31, 2003 consolidation, the Company recorded lease expense on the Wygen plant. Lease payments began upon completion of the plant in February 2003. During the twelve month period ended December 31, 2003, lease payments were \$2.7 million and are included in Operations and maintenance on the accompanying 2003 Consolidated Statement of Income. The net effect of consolidating the income statement of the VIE on December 31, 2003, was to recognize a cumulative effect charge for \$2.5 million (net of \$1.4 million of income taxes), which represents the depreciation and interest expense which would have been recorded had the VIE been consolidated at inception. The net effect on current results is to recognize depreciation and interest expense in place of recognizing lease expense. During the twelve month period ended December 31, 2004, depreciation expense was \$3.4 million and interest expense was \$3.6 million.

## 7 Long-Term Debt

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

	2004	2003
Senior unsecured notes at 6.5% due 2013	\$ 224,756	\$ 249,696
First mortgage bonds:		
8.06% due 2010	30,000	30,000
9.49% due 2018	3,970	4,260
9.35% due 2021	28,305	29,970
8.30% repaid 2004	-	45,000
7.23% due 2032	75,000	75,000
	137,275	184,230
Other long-term debt:		
Pollution control revenue bonds at 6.7% due 2010 <sup>(a)(b)</sup>	-	12,300
Pollution control revenue bonds at 4.8% due 2014 <sup>(b)</sup>	6,450	-
Pollution control revenue bonds at 7.5% due 2024 <sup>(b)</sup>	-	12,200
Pollution control revenue bonds at 5.35% due 2024 <sup>(b)</sup>	12,200	-
GECC Financing at 4.01% due 2010 <sup>(c)(d)</sup>	28,213	30,214
Other	5,362	6,253
	52,225	60,967
Project financing floating rate debt <sup>(d)</sup> :		
Fountain Valley project at 4.31% due 2006	82,661	132,328
Valmont and Arapahoe at 3.56% due 2007	124,565	130,632
Wygen project at 2.87% due 2006	111,100	111,100
Wygen project at 2.87% due 2008	17,165	17,165
	335,491	391,225
Total long-term debt	749,747	886,118
Less current maturities	(16,166)	(17,659)
Net long-term debt	\$ 733,581	\$ 868,459

(a) In September 2004, the Company's electric utility called \$5.9 million of pollution control revenue bonds without converting into another form of long-term debt.

(b) In the fourth quarter of 2004, the Company's electric utility called and refinanced \$18.7 million of pollution control revenue bonds.

(c) Floating rate debt, 86 percent secured by Gillette combustion turbine and 14 percent secured by a spare LM6000 turbine.

(d) Interest rates are presented as of December 31, 2004.

At December 31, 2004, approximately 31 percent of the Company's \$366.6 million variable rate debt balance has been hedged with interest rate swaps moving the floating rates to fixed rates with a weighted average interest rate of 4.22 percent (see Note 2).

Substantially all of the Company's utility property is subject to the lien of the indenture securing its first mortgage bonds. First mortgage bonds of the Company may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

Project financing debt is debt collateralized by a mortgage on each respective project's land and facilities, leases and rights, including rights to receive payments under long-term purchase power contracts. The Fountain Valley, Valmont and Arapahoe project debt is non-recourse debt. The Wygen project debt is additionally guaranteed by the Company (see Note 22).

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, 2004. Also, certain of the subsidiaries' debt agreements provide that approximately \$17.7 million of the subsidiaries' cash balance at December 31, 2004 may not be distributed to the parent company.

Scheduled maturities of long-term debt for the next five years are: \$16.2 million in 2005, \$200.4 million in 2006, \$115.5 million in 2007, \$21.2 million in 2008 and \$4.1 million in 2009.

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## 8 Notes Payable

The Company has committed lines of credit with various banks totaling \$350.0 million at December 31, 2004 and \$425.0 million at December 31, 2003. At December 31, 2004, these lines consist of a \$225.0 million revolving credit facility, which terminates August 20, 2006 and a \$125.0 million revolving credit facility that expires on May 12, 2005. The Company had \$24.0 million of borrowings and \$44.6 million of letters of credit and no borrowings and \$54.3 million of letters of credit issued on the lines at December 31, 2004 and 2003, respectively. The Company has no compensating balance requirements associated with these lines of credit.

Interest rates under the facility borrowings vary and are based, at the option of the Company at the time of the loan origination, on either (i) a prime based borrowing rate (5.25 percent at December 31, 2004) or (ii) on a London Interbank Offered Rate (LIBOR) based borrowing rate of LIBOR plus 1.25 percent to LIBOR plus 1.3 percent. The one-month LIBOR rate at December 31, 2004 was 2.4 percent. In addition to interest on outstanding borrowings, the credit facilities contain an annual facility fee of from 0.2 percent to 0.25 percent on the total facility amount, and an annual utilization fee of 0.25 percent.

In addition to the above lines of credit, at December 31, 2004, Enserco Energy (Enserco) has a \$150.0 million uncommitted, discretionary line of credit to provide support for the purchases of natural gas. The line of

credit is secured by all of Enserco's assets and expires on September 30, 2005. The Company has made a \$3.0 million guarantee to the lender associated with the line of credit. At December 31, 2004 and 2003, there were outstanding letters of credit issued under the facility of \$91.7 million and \$80.3 million, respectively, with no borrowing balances on the facility.

Black Hills Energy Resources (BHER) has a \$25.0 million uncommitted, discretionary credit facility at December 31, 2004. The facility is secured by cash, accounts receivable and other assets. The transactional line of credit provides credit support for the purchases of crude oil of BHER. The facility allows BHER to elect up to \$40.0 million of available credit via notification to the bank at the beginning of each calendar quarter. The Company and its other subsidiaries provide no guarantees to the lender. At December 31, 2004 and 2003, BHER had letters of credit outstanding of \$8.9 million and \$7.9 million, respectively, with no borrowing balances on the facility.

The credit facilities and notes payable contain certain restrictive covenants including, among others, the maintenance of a fixed charge coverage ratio, a recourse debt-to-capitalization ratio and a total level of equity. The Company and its subsidiaries had complied with all the covenants at December 31, 2004. These facilities do not contain default provisions pertaining to credit rating status.

The Company has entered into floating-to-fixed interest rate swaps to hedge a portion of its exposure to interest rate fluctuations with the above floating rate obligations. See Note 2 for further details.



## 9 Asset Retirement Obligations

SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143) provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and was effective January 1, 2003. SFAS 143 requires that the present value of retirement costs for which the Company has 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 Company has identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells in our Oil and Gas segment and reclamation of our coal mining sites in our Coal mining segment. Cumulative accretion and accumulated depreciation has been recognized for the time period from the date the liability would have been recognized had the provisions of SFAS 143 been in effect, to the date of its adoption. Upon adoption, the Company recorded a \$2.9 million transition adjustment to properly reflect its asset retirement obligations in accordance with the provisions of SFAS 143. The transition adjustment represents the current estimated fair value of the Company's obligation to plug its oil and gas wells at the time of abandonment and an adjustment to its liability for reclaiming its coal mining sites following completion of mining activity.

The cumulative effect on earnings of adopting SFAS 143 was a benefit of approximately \$0.2 million representing the cumulative amounts of depreciation and changes in the asset retirement obligation due to the passage of time for historical accounting periods. The cumulative effect of initially applying SFAS 143 was recognized as a change in accounting principle.

The following table presents the details of the Company's asset retirement obligations which are included on the accompanying Consolidated Balance Sheets in "Other" under "Deferred credits and other liabilities" (in thousands):

	Balance at 12/31/03	Liabilities Incurred	Liabilities Settled	Accretion	Cash Flow Revisions	Balance at 12/31/04
Oil and Gas	\$ 7,233	\$ 157	\$ -	\$ 552	\$ -	\$ 7,942
Mining	15,752	549	(1,102)	668	-	15,867
Total	\$ 22,985	\$ 706	\$ (1,102)	\$ 1,220	\$ -	\$ 23,809

## 10 Common Stock

During 2003, the Company completed a public offering of its common stock through which 4.6 million shares were sold at \$27 per share. Net proceeds were approximately \$118 million after commissions and expenses. The proceeds were used to pay off a \$50 million credit facility and to repay \$68 million under the Company's 364-day revolving credit facility, which expired on August 26, 2003. In addition, in 2003 the Company issued 481,509 shares and 45,000 warrants to purchase common stock in the acquisition of Mallon Resources Corporation (see Note 24).

### EQUITY COMPENSATION PLANS

The Company has several employee equity compensation plans, which allow for the granting of stock, restricted stock, restricted stock units, stock options, performance shares, and an employee stock purchase plan (ESPP). The Company accounts for such plans under APB No. 25, and has adopted the disclosure-only provisions of SFAS 123. For a discussion of the effect on earnings and earnings per common share for the years ended December 31, 2004, 2003 and 2002, if the Company had applied SFAS 123 and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant (see Note 1).

The Company has granted options with an option exercise price equal to the fair market value of the stock on the day of the grant. The Company has 318,330 shares available to grant at December 31, 2004. The options granted vest one-third each year for three years and expire after ten years from the grant date.

A summary of the status of the stock option plans at December 31, 2004, 2003 and 2002, and changes during the years then ended are as follows:

	2004		2003		2002	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	1,211,122	\$ 27.66	1,042,989	\$ 27.68	992,872	\$ 26.55
Granted	203,000	29.81	289,665	28.01	211,985	30.04
Forfeited	(53,154)	31.54	(66,153)	34.31	(34,838)	33.52
Exercised	(71,099)	22.12	(55,379)	22.00	(127,030)	21.20
Balance at end of year	1,289,869	\$ 28.14	1,211,122	\$ 27.66	1,042,989	\$ 27.68
Exercisable at end of year	885,894	\$ 27.68	747,482	\$ 26.45	566,654	\$ 25.36

Details of outstanding options at December 31, 2004 are as follows:

Option Exercise Prices	Shares Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Shares Exercisable	Weighted Average Exercise Price
\$16.67 to \$22.00	324,520	\$ 21.57	4.8 years	324,520	\$ 21.57
\$22.01 to \$27.00	204,005	\$ 24.32	6.0 years	174,656	\$ 24.18
\$27.01 to \$32.00	544,669	\$ 29.14	8.5 years	200,336	\$ 29.36
\$32.01 to \$37.00	109,175	\$ 34.42	7.3 years	79,482	\$ 34.39
\$37.01 to \$38.68	70,500	\$ 37.74	6.0 years	69,900	\$ 37.74
\$55.36	37,000	\$ 55.36	6.4 years	37,000	\$ 55.36

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options are as follows:

	2004	2003	2002
Weighted average fair value of options at grant date	\$6.90	\$2.74	\$6.63
Weighted average risk-free interest rate	3.82%	3.09%	4.17%
Weighted average expected price volatility	43.52%	46.80%	39.09%
Weighted average expected dividend yield	4.16%	4.28%	3.86%
Expected life in years	7	7	7

The Company maintains the ESPP under which it sells shares to employees at 90 percent of the stock's market price on the offering date. The Company issued 15,644, 24,963 and 17,496 shares of common stock under the ESPP in 2004, 2003 and 2002, respectively. At December 31, 2004, 119,705 shares are reserved and available for issuance under the ESPP.

During 2003 and 2001, the Company issued a total of 12,575 common shares and 36,550 common shares, respectively, as a stock bonus award to its non-officer employees. The bonuses were grossed up to cover related employee taxes. The total pre-tax compensation charge recognized by the Company was \$0.3 million and \$0.4 million in 2003 and 2002, which was based on the market value of the stock on the grant date.

The Company issued 16,019 and 45,123 restricted stock units in 2004 and 2003, respectively, and 34,828, 24,643 and 26,047 restricted common shares, to certain officers in 2004, 2003 and 2002, respectively. The shares carry a restriction on the officer's 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. The Company recognized pre-tax compensation cost related to the awards of \$1.7 million in 2004, \$0.9 million in 2003 and \$0.4 million in 2002. During 2003, the Company also issued 11,215 shares of common stock for the conversion of restricted stock units.

On March 1, 2004, certain officers of the Company and its subsidiaries were named participants in a performance share award plan. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group. In addition, the Company's stock price must also increase during the performance periods. Target grants of performance shares were made for the following performance periods:

Grant Date	Performance Period	Total Target Grant of Shares
March 1, 2004	March 1, 2004-December 31, 2005	15,458
March 1, 2004	March 1, 2004-December 31, 2006	31,384

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. Compensation expense recognized for the performance share awards for the year ended December 31, 2004 was \$0.5 million. The performance awards are paid in 50 percent cash and 50 percent common stock.

The Company issued 10,310, 3,075 and 38,749 shares of common stock in 2004, 2003 and 2002, respectively to certain key employees under the Short-term Annual Incentive Plan. The weighted average grant date fair value of the stock awards was \$31.10, \$23.10, and \$28.60, respectively.

## DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN

The Company has 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 percent of the recent average market price. The Company has the option of issuing new shares or purchasing the shares on the open market. The Company issued 22,934 new shares at a weighted average price of \$30.41 and 71,727 open market shares at a weighted average price of \$29.45 in 2004; 94,346 new shares in 2003 at a weighted average price of \$28.90; and 66,882 new shares in 2002 at a weighted average price of \$28.65. At December 31, 2004, 249,339 shares of unissued common stock were available for future offering under the Plan.

## DIVIDEND RESTRICTIONS

Some of the Company's credit facilities contain restrictions on the payment of cash dividends under a circumstance of default or event default. An event of default would be deemed to have occurred if the Company did not meet the financial covenant requirements for the respective facility. The most restrictive financial covenants include the following: fixed charge coverage ratio of not less than 1.5 to 1.0; a recourse leverage ratio not to exceed 0.65 to 1.00; and a minimum consolidated net worth of \$550 million plus 50 percent of our aggregate consolidated net income since April 1, 2004. As of December 31, 2004, we were in compliance with the above covenants. In addition, under PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. As part of the order approving our public utility holding company, we agreed that the consolidated company and the utility subsidiaries will maintain at least a 30 percent common equity ratio. Through December 31, 2007, our non-utility subsidiaries are also allowed to pay dividends out of capital and unearned surplus if (i) they have received excess cash as a result of the sale of assets, (ii) they have engaged in a restructuring or reorganization and/or (iii) they are returning capital to an associate company.

## TREASURY SHARES ACQUIRED

The Company acquired 4,005 and 4,400 shares of treasury stock related to a forfeiture of unvested restricted stock in 2004 and 2003, respectively, and 7,508, 3,119 and 696 shares related to the share withholding provisions of the restricted stock plan for the payment of taxes associated with the vesting of restricted shares in 2004, 2003 and 2002, respectively.

## 11 Preferred Stock

The Company has 25,000,000 authorized shares of no-par preferred stock of which 21,500 shares have been designated as the No Par Preferred Stock, Series 2000-A. As of December 31, 2004, 7,771 shares of the Series 2000-A has been issued, of which 6,839 shares were outstanding. During 2004, 932 shares of the Series 2000-A Preferred Stock were converted into 26,628 shares of common stock at the conversion price of \$35.00 per share.

The Company did not issue any preferred shares in 2004 or 2002, but issued 2,594 shares in 2003 in accordance with the Indeck Capital acquisition “earn-out” provisions (see Note 21). The preferred shares issued are non-voting, cumulative, no par shares with a dividend rate equal to 1 percent per annum per share, computed on the basis of \$1,000 per share plus an amount equal to any dividend declared payable with respect to the common stock, multiplied by the number of shares of common stock into which each share of preferred stock is convertible. The record and payment dates are the same as the record and payment dates with respect to the payment of dividends on common stock. No dividend may be declared or paid with respect to common stock unless such a dividend is declared and paid with respect to the preferred stock. The preferred stock is senior to the common stock in liquidation events.

The Company may redeem the preferred stock in whole or in part, at any time solely at its option. The redemption price per share for the preferred stock is \$1,000 per share plus all accrued and unpaid dividends. Each share of the preferred stock is convertible at the option of the holder into common stock at any time prior to July 7, 2005 and is automatically converted into common stock on July 7, 2005. Each share of preferred stock is convertible into 28.57 common shares. If the Company delivers a notice of redemption, the conversion price is adjusted equal to the lesser of (i) the conversion price then in effect, and (ii) the current market price on the redemption notice date.

## 12 Fair Value of Financial Instruments

The estimated fair values of the Company’s financial instruments are as follows (in thousands):

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	\$ 64,506	\$ 64,506	\$ 172,759	\$ 172,759
Restricted cash	\$ 3,069	\$ 3,069	\$ 1,350	\$ 1,350
Derivative financial instruments – assets	\$ 47,977	\$ 47,977	\$ 26,804	\$ 26,804
Derivative financial instruments – liabilities	\$ 43,206	\$ 43,206	\$ 32,967	\$ 32,967
Notes payable	\$ 24,000	\$ 24,000	\$ -	\$ -
Long-term debt, including current maturities	\$749,747	\$788,212	\$ 886,118	\$ 924,879

The following methods and assumptions were used to estimate the fair value of each class of the Company’s 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 the Company uses and the valuation method employed are available 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 the Company’s long-term debt is estimated based on quoted market rates for debt instruments having similar maturities and similar debt ratings. The Company’s outstanding first mortgage bonds are either currently not callable or are subject to make-whole provisions which would eliminate any economic benefits for the Company to call and refinance the bonds.



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## 13 Contract Termination Revenue

During the third quarter of 2003, the Company completed a transaction terminating a fifteen year contract with Allegheny Energy Supply Company, LLC, a subsidiary of Allegheny Energy, Inc., for capacity and energy at the Company's Las Vegas II power plant. The Company received a cash payment of \$114.0 million, which is recorded as "Contract termination revenue" in the accompanying Consolidated Statements of Income. Operating results from the Las Vegas II power plant are included in the Power Generation segment.

## 14 Impairment of Long-Lived Assets

As a result of the contract termination discussed in Note 13, the Company assessed the recoverability of the carrying value of the Las Vegas II facility. The carrying value of the assets tested for impairment was \$237.2 million. This assessment resulted in an impairment charge of \$117.2 million to write down the related Property, plant and equipment by \$83.1 million, net of accumulated depreciation of \$5.1 million, and intangible assets by \$34.1 million, net of accumulated amortization of \$1.1 million. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by its estimated future discounted cash flows. This charge is included as a component of "Operating expenses" on the accompanying Consolidated Statements of Income. Operating results from the Las Vegas II power plant are included in the Power Generation segment. In addition to the above asset impairment, certain long-lived assets accounted for as discontinued operations have incurred impairment charges (see Note 19).

## 15 Gain on Sale of Assets

On March 1, 2004, the Company's subsidiary, Daksoft, Inc., sold assets used in its campground reservation system. The Company recorded a pre-tax gain on the sale of the assets of \$1.0 million, which is included as an offset to Operating expenses, Administrative and general on the accompanying Consolidated Statement of Income. Prior to this sale, for segment reporting (see Note 23) results of operations for Daksoft were included in the Communications segment. As Daksoft now primarily provides information technology support to the Company, its results are included in "Corporate" for segment reporting.

## 16 Operating Leases

The Company has entered into lease agreements relating to certain power plant land leases, office facility leases and storage agreements.

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

2005	\$ 2,745
2006	1,552
2007	1,379
2008	1,400
2009	1,255
Thereafter	10,874
	<u>\$ 19,205</u>

# 17 Income Taxes

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

(in thousands)	2004	2003	2002
Current:			
Federal	\$ 223	\$ 35,414	\$ (3,78)
State	(2,705)	5,235	(1,494)
	(2,482)	40,649	(5,280)
Deferred:			
Federal	30,580	(6,625)	30,128
State	(1,115)	(4,105)	2,212
Tax credit amortization	(279)	(318)	(416)
	\$ 26,704	\$ 29,601	\$ 26,644

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

(in thousands)	2004	2003
Years ended December 31,		
Deferred tax assets, current:		
Valuation reserves	\$ 2,235	\$ 2,824
Mining development and oil exploration	377	980
Employee benefits	7,799	6,216
Items of other comprehensive income	1,680	2,375
Other	250	1,586
	12,341	13,981
Deferred tax liabilities, current:		
Prepaid expenses	2,156	1,733
Derivative fair value adjustments	188	850
Employee benefits	3,608	4,397
Items of other comprehensive income	618	160
Other	1,534	2,585
	8,104	9,725
Net deferred tax asset, current	\$ 4,237	\$ 4,256
Deferred tax assets, non-current:		
Accelerated depreciation, amortization and other plant-related differences	\$ 873	\$ 102
Mining development and oil exploration	205	213
Employee benefits	817	-
Regulatory asset	1,387	1,616
Deferred revenue	931	1,148
Items of other comprehensive income	1,149	2,147
Net operating loss (net of valuation allowance)	4,863	4,927
Asset impairment	40,061	41,023
Other	8,867	12,436
	59,153	63,612
Deferred tax liabilities, non-current:		
Accelerated depreciation, amortization and other plant-related differences	165,340	135,614
Regulatory liability	4,172	4,320
Mining development and oil exploration	34,126	20,445
Derivative fair value adjustments	110	614
Items of other comprehensive income	115	-
Other	14,913	27,659
	218,776	188,652
Net deferred tax liability, non-current	\$ 159,623	\$ 125,040
Net deferred tax liability	\$ 155,386	\$ 120,784

The following table reconciles the change in the net deferred income tax liability from December 31, 2003, to December 31, 2004, to deferred income tax expense:

(in thousands)	2004
Net change in deferred income tax liability from the preceding table	\$34,602
Deferred taxes associated with 2003 Federal Income Tax Return True-up primarily related to prepaid expenses and plant-related differences	(3,442)
Deferred taxes associated with other comprehensive loss	(2,266)
Deferred taxes related to net operating loss acquisitions	407
Other	(115)
Deferred income tax expense for the period	\$29,186

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

	2004	2003	2002
Federal statutory rate	35.0%	35.0%	35.0%
State income tax	(3.2)	0.8	0.5
Amortization of excess deferred and investment tax credits	(0.5)	(0.5)	(0.6)
Percentage depletion in excess of cost	(0.8)	(0.9)	(0.7)
Research and development credit	-	(0.6)	(1.5)
Other	1.3	0.6	(1.3)
	31.8%	34.4%	31.4%

At December 31, 2004, the Company had the following net operating loss carryforwards, which were acquired as part of the Mallon acquisition (in thousands):

Net Operating Loss Carryforward	Expiration Year
\$ 101	2009
336	2010
361	2011
48	2012
463	2013
22,789	2014-2023

As of December 31, 2004, the Company had a valuation allowance of \$19.2 million against these NOL carryforwards. Ultimate usage of these NOLs depends upon the Company's future tax planning and filings. If the valuation allowance is reduced due to higher than anticipated utilization of the NOLs, the offsetting amount would reduce the Company's financial reporting basis in its Mallon property.

# 18 Other Comprehensive Income (Loss)

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):

	2004		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	\$ 91	\$ (32)	\$ 59
Net change in fair value of derivatives designated as cash flow hedges	5,690	(2,234)	3,456
Other comprehensive income (loss)	\$ 5,781	\$ (2,266)	\$ 3,515

	2003		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	\$ 10,293	\$ (3,603)	\$ 6,690
Net change in fair value of derivatives designated as cash flow hedges (net of minority interest share of \$(331))	(592)	44	(548)
Reclassification adjustment for interest rate swaps designated as cash flow hedges settled as part of the hydroelectric asset sale and included in net income (net of minority interest share of \$(2,379))	6,361	(2,433)	3,928
Other comprehensive income (loss)	\$ 16,062	\$ (5,992)	\$ 10,070

	2002		
	Pre-tax Amount	Tax Benefit	Net-of-tax Amount
Minimum pension liability adjustments	\$ (13,556)	\$ 4,745	\$ (8,811)
Net change in fair value of derivatives designated as cash flow hedges (net of minority interest share of \$(164))	(13,342)	4,703	(8,639)
Other comprehensive income (loss)	\$ (26,898)	\$ 9,448	\$ (17,450)

# 19 Discontinued Operations

The Company accounts for its discontinued operations under the provisions of Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," (SFAS 144). Accordingly, results of operations and the related charges for discontinued operations have been classified as "Income from discontinued operations, net of tax" 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.

## SALE OF LANDRICA DEVELOPMENT CORP.

On May 21, 2004, the Company sold its subsidiary, Landrica Development Corp. Landrica's primary assets consisted of a coal enhancement plant and land. The purchaser made a \$0.5 million cash payment to the Company and assumed a \$2.9 million reclamation liability. The sale resulted in a \$2.1 million after-tax gain. For segment reporting purposes, Landrica was previously included in the Coal Mining segment.

Net income from the discontinued operations at December 31, is as follows (in thousands):

	2004	2003	2002
Pre-tax (loss) income from discontinued operations	\$ (40)	\$ 833	\$ 704
Pre-tax gain on disposal	3,208	-	-
Income tax expense	(1,120)	(319)	(263)
Net income from discontinued operations	\$ 2,048	\$ 514	\$ 441

Assets and liabilities of the discontinued operations are as follows (in thousands):

	December 31, 2003
Current assets	\$ 31
Property, plant and equipment	151
Investments	500
Non-current assets	-
Other current liabilities	(118)
Deferred reclamation	(2,858)
Other non-current liabilities	(1)
Net liabilities of discontinued operations	\$ (2,295)

## ADOPTION OF PLAN TO SELL PEPPERELL PLANT

During the third quarter of 2003, the Company adopted a plan to sell the 40 megawatt gas-fired Pepperell plant, which is part of the Power generation segment. The Pepperell plant is the Company's only remaining generation asset in the Eastern market and management has determined that it is a non-strategic asset. In connection with the plan to sell, the Company determined that the carrying value of the underlying assets exceeded their fair value and a charge to operations was required. Consequently, in the third quarter of 2003, the Company recorded an after-tax charge of approximately \$0.6 million.

The Company's original plan of sale included an expectation that the Pepperell plant would be sold by September 2004. While various market circumstances prevented a sale by this time, the Company continues to actively market the plant, taking actions necessary to respond to market changes. Consequently, in the fourth quarter of 2004, the Company recorded an additional after-tax charge of approximately \$0.7 million, which represents the difference between the carrying value of the assets versus the estimated fair value, less cost to sell.

For business segment reporting purposes, the Pepperell plant results were previously included in the Power Generation segment.

Revenues and net income from the discontinued operations during the years ended December 31, are as follows:

(in thousands)	2004	2003	2002
Operating revenues	\$ 120	\$ 2,152	\$ 3,572
Pre-tax income (loss) from discontinued operations	\$ (972)	\$ (1,422)	\$ (1,115)
Pre-tax loss on disposal	(1,064)	(3,464)	-
Income tax benefit	712	2,979	397
Net loss from discontinued operations	\$ (1,324)	\$ (1,907)	\$ (718)

Assets and liabilities of the discontinued operations at December 31, are as follows:

(in thousands)	2004	2003
Current assets	\$ 107	\$ 249
Property, plant and equipment	-	1,064
Non-current deferred tax asset	2,952	2,580
Other current liabilities	(167)	(86)
Non-current deferred tax liability	(484)	(381)
Net assets of discontinued operations	\$ 2,408	\$ 3,426

## SALE OF HYDROELECTRIC ASSETS

On September 30, 2003 the Company sold its seven hydroelectric power plants located in Upstate New York. The aggregate cash purchase price of approximately \$186 million was used in part to pay off the remaining amount of project-level debt and related interest rate swaps associated with these assets, which totaled approximately \$91 million. The purchasers are affiliates of Boralex, Inc., a Canadian corporation, and Boralex Power Income Fund, an unincorporated Canadian trust of which Boralex owns an interest (collectively the Purchaser). The agreements with the Purchaser required that the Company deliver 100 percent of the equity interests of the entities that owned the facilities and required that the Company acquire those minority interests which it did not then own, in advance of closing. In anticipation of entering into the agreements with the Purchaser, on July 8, 2003, the Company acquired the equity interests of a third party investor for \$9.0 million and entered into a definitive agreement to acquire the balance of the equity interests from another third party investor. For business segment reporting purposes, the hydroelectric power plants results were previously included in the Power Generation segment.

Revenues and net income from the discontinued operations at December 31, are as follows:

(in thousands)	2003	2002
Operating revenues	\$ 21,800	\$ 27,397
Pre-tax income from discontinued operations	\$ 7,986	\$ 8,484
Pre-tax gain on disposal	13,864	-
Income tax expense	(11,355)	(3,152)
Net income from discontinued operations	\$ 10,495	\$ 5,332



## SALE OF COAL MARKETING SUBSIDIARY

During the second quarter of 2002, the Company adopted a plan to dispose of its coal marketing subsidiary, Black Hills Coal Network. The sale and disposal was finalized in July 2002. In connection with the plan of disposal, the Company determined that the carrying values of some of the underlying assets exceeded their fair values and a charge to operations was required.

Consequently, in the second quarter of 2002, the Company recorded an after-tax charge of approximately \$1.0 million, which represents the difference between the carrying values of the assets and liabilities of the subsidiary versus their fair values, less cost to sell. In addition, during the first quarter of 2002, the Company had a \$0.8 million (pre-tax) impairment loss of certain intangibles as a result of a weak coal market. For business segment reporting purposes, the coal marketing business results were previously included in the Energy marketing and transportation segment.

Gross margins on energy trading contracts and net income from the discontinued operation at December 31, are as follows:

(in thousands)	2003	2002
Gross margins on energy trading contracts	\$ -	\$ 235
Pre-tax loss from discontinued operations	\$ -	\$ (2,679)
Pre-tax loss on disposal	-	(1,588)
Income tax benefit	834	1,630
Net income (loss) from discontinued operations	\$ 834	\$ (2,637)

## 20 Employee Benefit Plans

### DEFINED BENEFIT PENSION PLAN

The Company has a noncontributory defined benefit pension plan (Plan) covering the employees of the Company and those of the following subsidiaries, Black Hills Power, Wyodak Resources Development Corp., Black Hills Exploration and Production and Daksoft who meet certain eligibility requirements. The benefits are based on years of service and compensation levels during the highest five consecutive years of the last ten years of service. The Company's funding policy is in accordance with the federal government's funding requirements. The Plan's assets are held in trust and consist primarily of equity securities and cash equivalents. The Company uses a September 30 measurement date for the Plan.

### Obligations and Funded Status

Change in benefit obligation:

(in thousands)	2004	2003
Projected benefit obligation at beginning of year	\$61,879	\$50,888
Service cost	1,772	1,293
Interest cost	3,637	3,351
Actuarial (gain) loss	(237)	2,199
Discount rate change	-	6,414
Benefits paid	(2,291)	(2,221)
Taxable wage rate and cost of living rate change	-	(45)
Net increase	2,881	10,991
Projected benefit obligation at end of year	\$64,760	\$61,879

A reconciliation of the fair value of Plan assets (as of the September 30 measurement date) is as follows:

(in thousands)	2004	2003
Beginning market value of plan assets	\$48,797	\$32,437
Benefits paid	(2,291)	(2,221)
Investment income	6,276	8,081
Employer contributions	-	10,500
Ending market value of plan assets	\$52,782	\$48,797

Funding information for the Plan is as follows:

(in thousands)	2004	2003
Fair value of plan assets	\$52,782	\$48,797
Projected benefit obligation	(64,760)	(61,879)
Funded status	(11,978)	(13,082)
Unrecognized:		
Net loss	20,674	24,170
Prior service cost	1,377	1,609
Net asset recognized	\$10,073	\$12,697

Amounts recognized in statement of financial position consist of:

(in thousands)	2004	2003
Net pension asset	\$10,073	\$12,697
Accumulated benefit obligation	\$51,690	\$48,581

The provisions of SFAS No. 87 "Employers' Accounting for Pensions" (SFAS 87) required the Company to record a net pension asset of \$10.1 million and \$12.7 million at December 31, 2004 and 2003, respectively, which is included in the line item Other Assets on the accompanying Consolidated Balance Sheets.

### Components of Net Periodic Pension Expense

(in thousands)	2004	2003	2002
Service cost	\$ 1,772	\$ 1,293	\$ 979
Interest cost	3,637	3,351	3,135
Expected return on assets	(4,515)	(3,119)	(4,206)
Amortization of prior service cost	232	232	231
Recognized net actuarial (gain) loss	1,498	1,407	102
Net pension (income) expense	\$ 2,624	\$ 3,164	\$ 241

## Additional Information

(in thousands)	2004	2003
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	\$ -	\$12,474

## Assumptions

Weighted-average assumptions used to determine benefit obligations:

	2004	2003
Discount rate	6.00%	6.00%
Rate of increase in compensation levels	4.39%	5.00%

Weighted-average assumptions used to determine net periodic benefit cost for plan year:

	2004	2003	2002
Discount rate	6.00%	6.75%	7.50%
Expected long-term rate of return on assets*	9.50%	10.00%	10.50%
Rate of increase in compensation levels	4.39%	5.00%	5.00%

\*The expected rate of return on plan assets was changed from 9.5 percent in 2004 to 9.0 percent for the calculation of the 2005 net periodic pension cost. This change is expected to increase pension costs in 2005 by approximately \$0.3 million.

The Plan's 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 10.0 percent and 10.5 percent for the 2004 and 2003 plan years, respectively. For determining the expected long-term rate of return for equity assets, the Company reviewed annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2004, 13.2 percent, 13.7 percent, 10.4 percent and 10.9 percent respectively. Fund management fees were estimated to be 0.18 percent for S&P 500 Index assets and 0.45 percent for other assets. The expected long-term rate of return on fixed income investments was 6.0 percent; the return was based upon historical returns on intermediate-term treasury bonds of 6.3 percent from 1950 to 2002. The expected long-term rate of return on cash investments was estimated to be 4.0 percent; expected cash returns were estimated to be 2.0 percent below long-term returns on intermediate-term treasury bonds.

## Plan Assets

Percentage of fair value of Plan assets at September 30:

	2004	2003
Domestic equity	59.7%	44.8%
Foreign equity	34.5	26.6
Fixed income	2.6	3.8
Cash	3.2	24.8 <sup>(a)</sup>
Total	100.0%	100.0%

(a) Allocation includes \$10.5 million cash contribution made to the plan on September 30, 2003.

The Plan's investment policy includes a target asset allocation as follows:

Asset Class	Target Allocation
US Stocks	60% (with a variance of no more or less than 10% of target)
Foreign Stocks	30% (with a variance of no more or less than 10% of target)
Fixed Income	5% (with a variance of no more than 10% or no less than 5% of target)
Cash	5% (with a variance of no more than 10% or no less than 5% of target)

The Plan's investment policy includes the investment objective that the achieved long-term rate of return meet or exceed the assumed actuarial rate. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity-based assets. The policy provides that the Plan will maintain a passive core US Stock portfolio based on the S&P 500 Index. Complementing this core will be investments in US and foreign equities through actively managed mutual funds.

The policy contains certain prohibitions on transactions in separately managed portfolios in which the Plan 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 Plan assets if a fund engages in such transactions. The Plan has historically not invested in funds engaging in such transactions.

## Cash Flows

The Company does not anticipate any employer contributions to the Plan in 2005.

## Estimated Future Benefit Payments

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

2005	\$2,496
2006	2,519
2007	2,582
2008	2,689
2009	2,855
2010-2014	17,351

## SUPPLEMENTAL NONQUALIFIED DEFINED BENEFIT RETIREMENT PLANS

The Company has various supplemental retirement plans for outside directors and key executives of the Company. The Plans are nonqualified defined benefit plans. The Company uses a September 30 measurement date for the Plans.

### Obligations and Funded Status

(in thousands)	2004	2003
Change in benefit obligation:		
Projected benefit obligation at beginning of year	\$ 16,194	\$ 11,303
Service cost	536	425
Interest cost	965	759
Actuarial (gains) losses	(582)	6,107
Benefits paid	(133)	(120)
Discount rate change	-	2,256
Taxable wage rate and cost of living rate change	-	107
Change in salary projection	-	(4,643)
Net increase	786	4,891
Projected benefit obligation at end of year	\$ 16,980	\$ 16,194
Fair value of plan assets at end of year	\$ -	\$ -
Funded status	(16,980)	(16,194)
Unrecognized net loss	9,249	10,577
Unrecognized prior service cost	53	62
Contributions	84	30
Net amount recognized	\$ (7,594)	\$ (5,525)

(in thousands)	2004	2003
Amounts recognized in consolidated balance sheets consist of:		
Net pension (liability)	\$ (10,902)	\$ (8,886)
Intangible asset	52	68
Contributions	84	30
Accumulated other comprehensive loss	3,172	3,263
Net amount recognized	\$ (7,594)	\$ (5,525)
Accumulated benefit obligation	\$ 10,902	\$ 8,886

The provisions of SFAS 87 required the Company to record a net pension liability of \$10.9 million and \$8.9 million at December 31, 2004 and 2003, respectively. This amount is included in Deferred credits and other liabilities, Other on the accompanying Consolidated Balance Sheets.

### Components of Net Periodic Benefit Cost

(in thousands)	2004	2003	2002
Service cost	\$ 536	\$ 425	\$ 240
Interest cost	965	759	432
Amortization of prior service cost	9	(2)	26
Recognized net actuarial loss	748	511	145
Net periodic benefit cost	\$2,258	\$1,693	\$ 843

## Additional Information

(in thousands)	2004	2003
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	\$91	\$(2,181)

### Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30	2004	2003	
Discount rate	6.00%	6.00%	
Rate of increase in compensation levels	5.00%	5.00%	
Weighted-average assumptions used to determine net periodic benefit cost for plan year	2004	2003	2002
Discount rate	6.00%	6.75%	7.50%
Rate of increase in compensation levels	5.00%	5.00%	5.00%

### Plan Assets

The plans have no assets. The Company funds on a cash basis as benefits are paid.

### Estimated Cash Flows

The estimated employer contribution is expected to be \$0.3 million in 2005.

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

Fiscal Year Ending	
2005	\$316
2006	307
2007	308
2008	318
2009	296
2010-2014	1,361

## NON-PENSION DEFINED BENEFIT POSTRETIREMENT PLAN

Employees who are participants in the Company's Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service to the Company are entitled to postretirement healthcare benefits. These benefits are subject to premiums, deductibles, co-payment provisions and other limitations. The Company may amend or change the Plan periodically. The Company is not pre-funding its retiree medical plan. The Company uses a September 30 measurement date for the Plan.

These financial statements and this Note do not reflect the effects of the 2003 Medicare Act on the postretirement benefit plan.

## Obligation and Funded Status

(in thousands)	2004	2003
Change in benefit obligation:		
Accumulated postretirement benefit obligation at beginning of year	\$ 11,151	\$ 8,647
Service cost	561	383
Interest cost	662	576
Plan participant's contributions	385	381
Benefits paid and actual expenses	(611)	(606)
Actuarial (gains) losses	(1,156)	1,770
Net (decrease) increase	(159)	2,504
Accumulated postretirement benefit obligation at end of year	\$ 10,992	\$ 11,151
Fair value of plan assets at end of year	\$ -	\$ -
Funded status	(10,992)	(11,151)
Unrecognized net loss	2,538	3,882
Unrecognized prior service cost	(288)	(311)
Unrecognized transition obligation	1,198	1,348
Contributions	36	60
Net amount recognized	\$ (7,508)	\$ (6,172)

Amounts recognized on the accompanying Consolidated Balance Sheets consist of:

(in thousands)	2004	2003
Accrued postretirement liability	\$(7,508)	\$(6,172)

## Components of Net Periodic Benefit Cost

(in thousands)	2004	2003	2002
Service cost	\$ 561	\$ 383	\$ 284
Interest cost	662	576	519
Amortization of transition obligation	150	150	150
Amortization of prior service cost	(24)	(24)	(24)
Recognized net actuarial loss	189	89	35
Net periodic benefit cost	\$ 1,538	\$ 1,174	\$ 964

## Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30	2004	2003	
Discount rate	6.00%	6.00%	
Weighted-average assumptions used to determine net periodic benefit cost for plan year	2004	2003	2002
Discount rate	6.00%	6.75%	7.50%

The healthcare trend rate assumption for 2003 fiscal year disclosure and 2004 fiscal year expense and disclosure is 12 percent for fiscal 2004 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2011. The healthcare cost trend rate assumption for the 2003 fiscal year expense was 11 percent for fiscal 2003 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2009.

The healthcare cost trend rate assumption has a significant effect on the amounts reported. A 1 percent increase in the healthcare cost trend assumption would increase the service and interest cost \$0.3 million or 24 percent and the accumulated periodic postretirement benefit obligation \$2.2 million or 20 percent. A 1 percent decrease would reduce the service and interest cost by \$0.2 million or 18 percent and the accumulated periodic postretirement benefit obligation \$1.7 million or 16 percent.

## Plan Assets

The plan has no assets. The Company funds on a cash basis as benefits are paid.

## Estimated Cash Flows

The estimated employer contribution is expected to be \$0.2 million in 2005.

## Estimated Future Benefit Payments

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

Fiscal Year Ending	
2005	\$238
2006	277
2007	306
2008	337
2009	390
2010-2014	2,759

## DEFINED CONTRIBUTION PLAN

The Company also sponsors a 401(k) savings plan for eligible employees. Participants elect to invest up to 20 percent of their eligible compensation on a pre-tax basis. The Company provides a matching contribution of 100 percent of the employee's tax-deferred contribution up to a maximum of 3 percent of the employee's eligible compensation. Matching contributions vest at 20 percent per year and are fully vested when the participant has 5 years of service with the Company. The Company's matching contributions totaled \$1.4 million for 2004, \$1.4 million for 2003 and \$1.3 million for 2002.



## VARIABLE INTEREST ENTITY

The Company's subsidiary, Black Hills Wyoming, has an Agreement for Lease and Lease with Wygen Funding, Limited Partnership (the variable interest entity) for the Wygen plant. The Company is considered the "primary beneficiary" and therefore the variable interest entity has been consolidated by the Company into the accompanying consolidated financial statements (see Note 6). The initial term of the lease is five years, with two five-year renewal options, and includes a purchase option equal to the adjusted acquisition cost. The adjusted acquisition cost is essentially equal to the cost of the plant. At the end of each lease term, the Company may renew the lease, purchase the plant, or sell the plant on behalf of the variable interest entity, to an independent third party. If the project is sold and the proceeds from the sale are insufficient to repay the investors, the Company will be required to make a payment to the variable interest entity of the shortfall up to 83.5 percent of the adjusted acquisition cost, or approximately \$111.1 million. The Company has guaranteed the obligations of Black Hills Wyoming to the variable interest entity. As discussed in Note 6, the Company has recorded the debt of the Variable Interest Entity on the Consolidated Balance Sheet, which was \$128.3 million at December 31, 2004.

## ACQUISITION EARN-OUT AGREEMENT

On July 7, 2000, the Company acquired Indeck Capital, Inc. and merged it into its subsidiary, Black Hills Generation (f/k/a Black Hills Energy Capital, Inc.). The acquisition was a stock transaction with the Company issuing 1,536,747 shares of common stock to the shareholders of Indeck priced at \$21.98 per share, along with \$4.0 million in preferred stock, resulting in a purchase price of \$37.8 million. Additional consideration, consisting of common and preferred stock, was payable in the form of an earn-out over a four-year period beginning in 2000. As of December 31, 2004, earn-out consideration valued at \$13.7 million for book purposes has been recorded. Litigation concerning the earn-out is described in "Legal Proceedings" within this note. Additional consideration paid out under the earn-out is recorded as an increase to goodwill. The earn-out consideration is based on the acquired company's earnings during such period and cannot exceed \$35.0 million in total.

## POWER PURCHASE AND TRANSMISSION SERVICES AGREEMENTS – PACIFI POWER

In 1983, the Company entered into a 40 year power purchase agreement with PacifiCorp providing for the purchase by the Company of 75 megawatts of electric capacity and energy from PacifiCorp's system. An amended agreement signed in October 1997 reduces the contract capacity by 25 megawatts (5 megawatts per year starting in 2000). 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 \$10.0 million in 2004, \$10.8 million in 2003 and \$10.9 million (net of a \$1.3 million refund for prior years) in 2002.

In addition, the Company has a firm network transmission agreement for 36 MWs of capacity with PacifiCorp that expires on December 31, 2006. Annual costs are approximately \$0.9 million per year. The Company uses this agreement to serve the Sheridan, Wyoming electric service territory under our contract with Montana-Dakota Utilities Company.

The Company also has a firm point-to-point transmission service agreement with PacifiCorp that expires on December 31, 2023. The agreement provides that the following amounts of capacity and energy be transmitted: 32 megawatts in 2001, 27 megawatts in 2002, 22 megawatts in 2003, 17 megawatts in 2004-2006 and 50 megawatts in 2007-2023. Costs incurred under this agreement were \$0.4 million in 2004, \$0.5 million in 2003 and \$0.7 million in 2002.

## LONG-TERM POWER SALES AGREEMENTS

The Company, through its subsidiaries, has the following significant long-term power sales contracts:

- The Company has long-term power sales contracts with Public Service Company of Colorado (PSCO) for the output of several of its plants. All of the output of the Company's Fountain Valley, Arapahoe and Valmont gas-fired facilities, totaling 450 megawatts, is included under the contracts which expire in 2012. The contracts are treated as leases under accounting principles generally accepted in the United States and establish capacity and availability payments over the lives of the contracts. The contracts are tolling arrangements in which the Company assumes no fuel price risk.

- The Company has a ten-year power sales contract with Cheyenne Light, Fuel and Power (CLF&P) for the output of the 40 megawatt gas-fired Gillette CT. The Company assumes fuel price risk under this agreement since the fuel price is fixed at the outset of each month and CLF&P has the right to dispatch the facility on a day-ahead basis. The Company is permitted to remarket the energy that is not prescheduled by CLF&P. This agreement has been temporarily assigned from CLF&P to its former affiliate, PSCO, for the four-year term of CLF&P's all requirements power purchase agreement with PSCO, which expires December 31, 2007. The Company acquired CLF&P on January 21, 2005 (see Note 25).
- The Company has a ten-year contract with CLF&P for 60 megawatts of contingent capacity from the 90 megawatt Wygen plant. The Company has consented, subject to receipt of lender approval, to CLF&P's assignment of this agreement to its affiliate, PSCO, for the term of its all requirements power purchase agreement, which expires December 31, 2007. Twenty megawatts of the remaining capacity of this plant has been sold under a ten year unit contingent contract with the Municipal Energy Agency of Nebraska (MEAN).
- The Company has a ten-year power sales contract with the MEAN for 20 megawatts of contingent capacity from the Neil Simpson Unit #2 plant. The contract commenced in February, 2003.
- The Company has a long-term contract for the output of the 53 megawatt Las Vegas I plant with Nevada Power Company (NPC) through 2024.
- The Company has a long-term contract to provide capacity and energy from the Las Vegas II plant to NPC. The contract became effective April 1, 2004 and expires December 31, 2013. The contract is a tolling arrangement whereby NPC is responsible for supplying natural gas. The Las Vegas II power plant, comprised of combined-cycle gas turbines, is rated at 224 megawatts. The power plant's capacity and energy will be fully dispatchable by NPC to serve its retail load.
- The Company has entered into a tolling agreement with Southern California Edison for all of the capacity and energy from the Company's gas-fired Harbor Cogeneration plant. The agreement commences April 1, 2005 and expires May 31, 2008. Through October 2004, the facility sold capacity and energy under a seasonal agreement that ran from June through October of each year.
- The Company has a contract with Montana-Dakota Utilities Company, expiring January 1, 2007, for the sale of up to 55 megawatts of energy and capacity to service the Sheridan, Wyoming electric service territory. The Company also has a contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 megawatts of capacity and energy. Both contracts are served by BHP and are integrated into its control area and are treated as part of the utility's firm native load.

## TRANSMISSION SERVICES AGREEMENT

The Company has a Firm Point-To-Point Transmission Service Agreement (TSA) with NPC related to the Las Vegas II power plant that expires April 30, 2008. The TSA provided transmission service in support of a Capacity and Ancillary Services Sale and Tolling Services Agreement with Allegheny Energy Supply Company, LLC (Allegheny), which was terminated in September 2003. On April 1, 2004, the Company's new long-term tolling contract to provide capacity and energy from the Las Vegas II plant to NPC became effective. The Las Vegas II plant is interconnected with NPC's transmission system through a step-up transformer owned by Las Vegas Cogeneration II, LLC, pursuant to an interconnection agreement on file with FERC. To the extent that transmission rights established under the TSA cannot be remarketed, costs under the agreement may not be recoverable. Payments under the TSA are approximately \$3.9 million per year based on current tariffs. In its consideration and approval of the NPC tolling contract, the Nevada Public Utilities Commission established a linkage between the TSA and the tolling contract that results in the Company recognizing the costs of the TSA over the term of the tolling contract (10 years, \$1.6 million per year) rather than the remaining term of the TSA (3.5 years, \$3.9 million per year).

## RECLAMATION LIABILITY

Under its mining permit, Wyodak Resources 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 \$0.7 million and \$0.6 million was charged to accretion expense for the years ended December 31, 2004 and 2003, respectively. Approximately \$0.5 million and \$0.3 million was charged to depreciation expense for the years ended December 31, 2004 and 2003. Approximately \$0.9 million was charged to operations as reclamation expense in 2002. Accrued reclamation costs included in Other in Deferred credits and other liabilities on the accompanying Consolidated Balance Sheets were approximately \$15.9 million and \$15.8 million at December 31, 2004 and 2003, respectively.

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## LEGAL PROCEEDINGS

### Forest Fire Claims

In September 2001, a fire occurred in the southwestern Black Hills, now known as the “Hell Canyon Fire.” It is alleged that the fire occurred when a high voltage electrical span maintained by the Company’s electric utility, BHP, broke, and electrical arcing from the severed line ignited dry grass. The fire burned approximately 10,000 acres of land owned by the Black Hills National Forest, the Oglala Sioux Tribe, and other private landowners. The State of South Dakota initiated litigation against BHP, in the Seventh Judicial Circuit Court, Fall River County, South Dakota, on or about January 31, 2003. The Complaint seeks recovery of damages for alleged fire suppression and rehabilitation costs. A claim for treble damages is asserted with respect to the claim for injury to timber. A substantially similar suit was filed against BHP by the United States Forest Service, on June 30, 2003, in the United States District Court for the District of South Dakota, Western Division. The State subsequently joined its claim in the federal action. The State claims damages in the amount of approximately \$0.8 million for fire suppression and rehabilitation costs. The United States Government’s claim for fire suppression and related costs has been submitted at approximately \$1.3 million. The Company continues to investigate the cause and origin of the fire, and the damage claims. A trial date has been set for early 2005. The Company has denied all claims and will vigorously defend this matter, the timing or outcome of which is uncertain.

On June 29, 2002, a forest fire began near Deadwood, South Dakota, now known as the “Grizzly Gulch Fire.” Before being contained more than eight days later, the fire consumed over 10,000 acres of public and private land, mostly consisting of rugged forested areas. The fire destroyed approximately 7 homes, and 15 outbuildings. There were no reported personal injuries. In addition, the fire burned to the edge of the City of Deadwood, forcing the evacuation of the City of Deadwood, and the adjacent City of Lead, South Dakota. These communities are active in the tourist and gaming industries. Individuals were ordered to leave their homes, and businesses were closed for a short period of time. On July 16, 2002, the State of South Dakota announced the results of its investigation of the cause and origin of the fire. The State asserted that the fire was caused by tree encroachment into and contact with a transmission line owned and maintained by BHP.

On September 6, 2002, the State of South Dakota commenced litigation against BHP, in the Seventh

Judicial Circuit Court, Pennington County, South Dakota. The Complaint seeks recovery of damages for alleged injury to timber, fire suppression and rehabilitation costs. A claim for treble damages was asserted with respect to the claim for injury to timber.

On March 3, 2003, the United States of America filed a similar suit against BHP, in the United States District Court, District of South Dakota, Western Division. The federal government’s Complaint likewise seeks recovery of damages for alleged injury to timber, fire suppression and rehabilitation costs. A similar claim for treble damages is asserted with respect to the claim for injury to timber. In April 2003, the State of South Dakota intervened in the federal action. Accordingly, the state court litigation has been stayed, and all governmental claims will be tried in U.S. District Court.

The state and federal government claim approximately \$5.3 million for suppression costs, \$1.2 million for rehabilitation costs, and \$0.6 million for timber loss. Additional claims could be asserted for alleged loss of habitat and aesthetics or for assistance to private landowners.

BHP is completing its own investigation of the fire cause and origin. BHP’s investigation is continuing, but based upon information currently available, BHP filed its Answer to the Complaints of both the State and the United States government, denying all claims, and asserting that the fire was caused by an independent intervening cause, or an act of God. The Company expects to vigorously defend all claims brought by governmental or private parties.

During the period of April 2003 through September 2004, various private civil actions were filed against BHP, asserting that the Grizzly Gulch Fire caused damage to the parties’ real property. These actions were filed in the Fourth Judicial Circuit Court, Lawrence County, South Dakota. The Complaints seek recovery on the same theories asserted in the governmental Complaints, but most of the Complaints specify no amount for damage claims. The Company will vigorously defend these matters as well.

Additional claims could be made for individual and business losses relating to injury to personal and real property, and lost income.

Although we cannot predict the outcome or the viability of potential claims with respect to either fire, based on the information available, management believes that any such claims, if determined adversely to the Company, will not have a material adverse effect on the Company’s financial condition or results of operations.

## **PPM Energy, Inc. Demand for Arbitration**

On January 2, 2004, PPM Energy, Inc. delivered a Demand for Arbitration to BHP. The demand alleges claims for breach of contract and requests a declaration of the parties' rights and responsibilities under an Exchange Agreement executed on or about April 3, 2001. Specifically, PPM Energy asserts that the Exchange Agreement obligates BHP to accept receipt and cause corresponding delivery of electric energy, and to grant access to transmission rights allegedly covered by the Agreement. PPM Energy requests an award of damages in an amount not less than \$20.0 million. BHP filed its Response to Demand, including a counterclaim that seeks recovery of sums PPM has refused to pay pursuant to the Exchange Agreement. The Company denies all claims and will vigorously defend this matter, the timing and outcome of which is uncertain.

## **Price Reporting Class Actions**

### **A. Cornerstone Propane Partners, L.P.**

On August 18, 2003, Cornerstone Propane Partners, L.P. commenced a putative class action lawsuit against over thirty energy companies. *Cornerstone Propane Partners, L.P. v. Reliant Energy Services, Inc., et. al.*, Civ. No. 03-CV-6168 (U.S. District Court, Southern District of New York) ("Cornerstone Propane Litigation"). The Complaint, which names Black Hills Corporation and Enserco Energy Inc. as defendants, asserts claims for an unspecified amount of damages, based upon alleged violations of the Commodity Exchange Act. General allegations in the Complaint assert that defendants manipulated natural gas futures contracts through false reporting of prices and volumes. Similar specific allegations are made against Black Hills Corporation and Enserco, based upon claims that former traders at Enserco reported false price and volume information to trade publications. Other defendants are alleged to have manipulated spot market gas prices by engaging in "wash trades" and/or by "churning" natural gas trades. Initially, the plaintiff seeks an order certifying the proceeding as a class action according to applicable rules.

### **B. Roberto E. Calle Gracey**

On October 1, 2003, Roberto E. Calle Gracey commenced a putative class action lawsuit against a group of defendants that sets forth claims and demands similar to those described above with respect to the *Cornerstone Propane Litigation*. Black Hills Corporation and Enserco Energy, Inc. are named as defendants in this action as well. *Gracey v. American Electric Power Company, Inc., et. al.*, Civ. No., 03-CV-7750 (U.S. District Court, Southern District of New York).

## **C. In re Natural Gas Commodity Litigation**

On December 5, 2003, the actions cited in paragraphs A and B above, were consolidated with other actions involving similar claims against other parties, in a civil action captioned *In re Natural Gas Commodity Litigation*, 03 CV 6186(VM), United States District Court, Southern District of New York. All further proceedings relative to these matters will be conducted in the consolidated action. The consolidated class action now includes claims against a number of companies, based upon a variety of alleged misconduct. The claims against Black Hills Corporation and Enserco comprise a relatively small part of only one category of the total claims included in this lawsuit. The action has not been certified to proceed as a class action. Motions to Dismiss were denied. Defendants will make an effort to "decertify" the matter as a class action based upon the dissimilarity of parties, claims and issues. While it is possible for an individual to state a claim for relief based upon allegations such as those made against Black Hills Corporation and Enserco, those Plaintiffs that have asserted claims against Black Hills Corporation and Enserco have a number of procedural and substantive hurdles to overcome. Even if Plaintiff's claims survive Motions to Dismiss, and successfully avoid class decertification, they still must prove actual damages as a result of the conduct of an individual Defendant, such as Black Hills Corporation and Enserco. Based upon information currently available, and given the current status of the litigation, we do not believe it is likely that Plaintiffs will be able to succeed in recovering on a claim in an amount that would be material to the Company's consolidated financial position or results of operations.

### **Acquisition Earn-Out Agreement Lawsuit**

On August 13, 2004, the former shareholders of Indeck Capital, Inc. (Indeck) commenced litigation against the Company in United States District Court, Northeastern District of Illinois, Eastern Division. The lawsuit concerns the Company's performance of its obligation under the "Earn-out" provisions of the Agreement and Plan of Merger dated July 7, 2000, related to the Company's acquisition of Indeck. Under the "Earn-out" provisions, the former shareholders of Indeck were entitled to receive "contingent merger consideration" for a four year period beginning in 2000. The "contingent merger consideration" was not to exceed \$35.0 million and was based on the acquired company's earnings over the four year period. As of December 31, 2004, \$11.3 million has been either paid or offered for payment under the "Earn-out" provisions.

The lawsuit alleges that the Company failed to meet its obligation to produce documentation for its calculation of the contingent merger consideration, and in addition, failed to issue stock compensation in the full amount due



to them. The Company denies these allegations and believes that it has fully and in good faith performed all of its obligations under the Agreement and Plan of Merger. In addition, the Company contends that that Agreement and Plan of Merger provides for mandatory arbitration as a medium for resolution of all disputes relating to the payment of contingent merger consideration, and will aggressively pursue the dismissal of the litigation. The outcome of this matter is uncertain, as is the amount of contingent merger consideration that could be awarded following arbitration or litigation.

## Ongoing Proceedings

The Company is subject to various other legal proceedings, claims and litigation which arise in the ordinary course of operations. In the opinion of management, the amount of liability, if any, with respect to these actions would not materially affect the consolidated financial position or results of operations of the Company.

# 22 Guarantees

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

As prescribed in FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45), the Company records a liability for the fair value of the obligation it has undertaken for guarantees issued after December 31, 2002. The liability recognition requirements of FIN 45 are to be applied on a prospective basis to guarantees issued or modified after December 31, 2002, while the disclosure requirements are applied to all guarantees.

As of December 31, 2004, the Company had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2004	Year Expiring
Guarantee payments under the Las Vegas Cogen I Power Purchase and Sales Agreement with Sempra Energy Solutions	\$ 10,000	Upon 5 days written notice
Guarantee of certain obligations under Enserco's credit facility	3,000	2005
Guarantee of obligation of Las Vegas Cogen II under an interconnection and operation agreement	750	2005
Guarantee payments of Black Hills Power under various transactions with Idaho Power Company	500	2005

(continued in next column)

(continued from previous column)	Outstanding at December 31, 2004	Year Expiring
Guarantee payments of Black Hills Power under various transactions with Southern California Edison Company	750	2005
Guarantee obligations under the Wygen Plant Lease	111,018	2008
Guarantee payment and performance under credit agreements for two combustion turbines	28,213	2010
Guarantee payments of Las Vegas Cogen II to Nevada Power Company under a power purchase agreement	5,000	2013
Indemnification for subsidiary reclamation/surety bonds	25,420	Ongoing
	<b>\$ 184,651</b>	

The Company has guaranteed up to \$10.0 million of payments of its power generation subsidiary, Las Vegas Cogeneration Limited Partnership, to Sempra Energy Solutions which may arise from transactions entered into by the two parties under a Master Power Purchase and Sale Agreement. To the extent liabilities exist under this power and purchase sale agreement subject to this guarantee, such liabilities are included in the Consolidated Balance Sheets. The guarantee may be terminated for future transactions upon five days written notice.

The Company has guaranteed up to \$3.0 million of Enserco Energy Inc.'s obligations to Fortis Capital Corp. under its credit facility. There are no liabilities on the Company's Consolidated Balance Sheets associated with this guarantee.

The Company has guaranteed up to \$0.8 million of the obligations of Las Vegas Cogeneration II, LLC under an interconnection and operations agreement for the LV II unit. To the extent liabilities exist under the interconnection and operations agreement, such liabilities are included in the Consolidated Balance Sheets. The obligation is due May 20, 2005.

The Company has guaranteed up to \$0.5 million of the obligations of its electric utility subsidiary, BHP, under various transactions with Idaho Power Company. To the extent liabilities exist under these transactions and subject to this guarantee, such liabilities are included in the Consolidated Balance Sheets. This guarantee expired on March 1, 2005 and the Company issued a similar guarantee in the amount of \$0.2 million on March 1, 2005.

The Company has guaranteed up to \$0.8 million of the obligations of its electric utility subsidiary, BHP, under various transactions with Southern California Edison Company. To the extent liabilities exist under these transactions which are subject to this guarantee, such liabilities are included in the Consolidated Balance Sheets. This guarantee expires on the earlier of April 1,

2005 or 30 days after the date creditor receives written notification from guarantor.

The Company has guaranteed the obligations of Black Hills Wyoming under the Agreement for Lease and Lease for the Wygen plant. The Company consolidates the Variable Interest Entity that owns the plant into its financial statements; therefore the obligations associated with this guarantee are included in the Consolidated Balance Sheets. If the lease was terminated and sold, the Company's obligation is the amount of deficiency in the proceeds from the sale to repay the investors up to a maximum of 83.5 percent of the cost of the project. At December 31, 2004, the Company's maximum obligation under the guarantee is \$111.0 million (83.5 percent of \$133.0 million, the cost incurred for the Wygen plant). The initial term of the lease is five years with two five-year renewal options.

The Company has guaranteed the payment of \$24.2 million of debt of Black Hills Wyoming and \$4.0 million of debt for another of the Company's wholly-owned subsidiaries, Black Hills Generation. The debt is recorded on the Company's Consolidated Balance Sheets and is due December 18, 2010.

The Company has guaranteed up to \$5.0 million of payments of its power generation subsidiary, Las Vegas Cogeneration II, LLC under the Western Systems Power Pool Confirmation Agreement with Nevada Power Company. To the extent liabilities exist under the agreements subject to this guarantee, such liabilities are included in the Consolidated Balance Sheets. The guarantee expires upon payment in full of all the obligations under the contract, which expires in 2013.

In addition, at December 31, 2004, the Company had guarantees in place totaling approximately \$25.4 million for reclamation and surety bonds for its 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 the Company's Consolidated Balance Sheets.

## 23 Business Segments

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of December 31, 2004, substantially all of the Company's operations and assets are located within the United States. The Company's operations are conducted through six business segments that include: Wholesale Energy consisting of: Coal Mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; Oil and Gas, which produces, explores and

operates oil and natural gas interests located in the Rocky Mountain region, Texas, California and other states; Energy Marketing and Transportation, which markets natural gas, oil and related services to customers in the Midwest, Southwest, Rocky Mountain, West Coast and Northwest regional markets; Power Generation, which produces and sells power and capacity to wholesale customers; and Retail Services consisting of: Electric utility, which supplies electric utility service to western South Dakota, northeastern Wyoming and southeastern Montana and Communications, which primarily markets broadband communications services.

Prior to 2004, the Company's communications segment marketed campground reservation services and software development services to external parties through Daksoft, Inc. With the sale of certain assets and a change in its business strategy, Daksoft now primarily provides information technology support to the Company. With its focus now on corporate support, beginning with the first quarter 2004, Daksoft's results of operations are included with corporate results.

(in thousands)		
December 31:	2004	2003
<b>Total assets</b>		
Wholesale energy:		
Coal mining	\$ 55,310	\$ 45,989
Oil and gas	194,203	145,371
Energy marketing and transportation	373,286	256,059
Power generation	826,240	876,160
Electric utility	464,361	463,869
Communications	116,373	126,204
Corporate	23,331	145,025
Discontinued operations	3,059	4,575
<b>Total assets</b>	<b>\$2,056,163</b>	<b>\$2,063,252</b>

### Capital expenditures and acquisitions

Wholesale energy:		
Coal mining	\$ 3,183	\$ 8,203
Oil and gas	53,891	43,448
Energy marketing and transportation	622	822
Power generation	6,043	28,798
Electric utility	13,347	25,427
Communications	8,101	8,178
Corporate	5,787	1,815
<b>Total capital expenditures and acquisitions</b>	<b>\$ 90,974</b>	<b>\$ 116,691</b>

### Property, plant and equipment

Wholesale energy:		
Coal mining	\$ 73,367	\$ 72,285
Oil and gas	259,695	205,137
Energy marketing and transportation	28,459	27,838
Power generation	792,385	791,684
Electric utility	637,278	622,849
Communications	165,351	159,534
Corporate	14,584	3,218
<b>Total property, plant and equipment</b>	<b>\$1,971,119</b>	<b>\$1,882,545</b>

(in thousands) December 31:	2004	2003	2002
<b>External operating revenues</b>			
Wholesale energy:			
Coal mining	\$ 19,669	\$ 22,232	\$ 20,811
Oil and gas	59,191	46,648	26,043
Energy marketing and transportation <sup>(a)</sup>	662,110	675,586	553,688
Power generation <sup>(b)</sup>	158,037	284,567	102,548
Electric utility	172,774	170,942	162,186
Communications	39,586	39,763	32,677
Corporate	761	-	-
<b>Total external operating revenues</b>	<b>\$1,112,128</b>	<b>\$1,239,738</b>	<b>\$ 897,953</b>

(a) Operating revenues for energy marketing and transportation are presented in accordance with EITF 02-3 and EITF 99-19, as described in Note 1.

(b) Power generation revenue in 2003 includes \$114 million of contract termination revenue as described in Note 13.

#### Intersegment operating revenues

Wholesale energy:			
Coal mining	\$ 12,298	\$ 12,545	\$ 10,524
Oil and gas	343	329	443
Electric utility	971	77	-
Corporate	2,672	-	-
Intersegment eliminations	(6,711)	(2,639)	(443)
<b>Total intersegment operating revenues<sup>(c)</sup></b>	<b>\$ 9,573</b>	<b>\$ 10,312</b>	<b>\$ 10,524</b>

(c) In accordance with the provisions of SFAS 71, intercompany fuel sales to the Company's regulated utility, Black Hills Power, are not eliminated.

#### Depreciation, depletion and amortization

Wholesale energy:			
Coal mining	\$ 5,142	\$ 3,808	\$ 3,358
Oil and gas	13,028	10,000	7,799
Energy marketing and transportation	1,201	1,183	932
Power generation	34,535	31,727	21,452
Electric utility	18,873	18,999	17,499
Communications	13,793	14,515	12,678
Corporate	1,261	559	147
<b>Total depreciation, depletion and amortization</b>	<b>\$ 87,833</b>	<b>\$ 80,791</b>	<b>\$ 63,865</b>

#### Operating income (loss)

Wholesale energy:			
Coal mining	\$ 8,454	\$ 8,775	\$ 9,457
Oil and gas	19,181	13,258	6,471
Energy marketing and transportation	18,181	12,151	17,816
Power generation	47,934	58,893	35,362
Electric utility	43,809	51,099	58,160
Communications	(2,334)	(5,241)	(7,447)
Corporate	(1,306)	(7,767)	(7,103)
<b>Total operating income</b>	<b>\$ 133,919</b>	<b>\$ 131,168</b>	<b>\$ 112,716</b>

(in thousands) December 31:	2004	2003	2002
<b>Interest income</b>			
Wholesale energy:			
Coal mining	\$ 1,393	\$ 2,473	\$ 3,459
Oil and gas	12	832	2
Energy marketing and transportation	728	1,236	1,634
Power generation	24,559	23,720	22,254
Electric utility	696	1,512	734
Communications	-	-	3
Corporate	15,626	16,090	16,680
Intersegment eliminations	(41,256)	(44,787)	(44,157)
<b>Total interest income</b>	<b>\$ 1,758</b>	<b>\$ 1,076</b>	<b>\$ 609</b>

#### Interest expense

Wholesale energy:			
Coal mining	\$ 226	\$ 757	\$ 2,453
Oil and gas	1,578	2,054	59
Energy marketing and transportation	877	885	564
Power generation	49,758	53,854	41,454
Electric utility	16,019	17,044	13,663
Communications	3,748	3,827	3,993
Corporate	20,892	18,945	15,535
Intersegment eliminations	(41,256)	(44,787)	(44,157)
<b>Total interest expense</b>	<b>\$ 51,842</b>	<b>\$ 52,579</b>	<b>\$ 33,564</b>

#### Income taxes

Wholesale energy:			
Coal mining	\$ 2,574	\$ 2,423	\$ 2,957
Oil and gas	5,315	3,978	1,739
Energy marketing and transportation	7,811	5,778	6,396
Power generation	6,711	11,795	7,430
Electric utility	9,512	11,622	15,067
Communications	(2,127)	(3,184)	(3,948)
Corporate	(3,092)	(2,811)	(2,997)
<b>Total income taxes</b>	<b>\$ 26,704</b>	<b>\$ 29,601</b>	<b>\$ 26,644</b>

#### Income (loss) from continuing operations before change in accounting principle

Wholesale energy:			
Coal mining	\$ 7,463	\$ 8,289	\$ 8,131
Oil and gas	12,200	8,400	4,783
Energy marketing and transportation	10,222	6,725	12,739
Power generation	15,562	22,429	12,523
Electric utility	19,209	24,089	30,217
Communications	(3,941)	(5,880)	(7,260)
Corporate	(3,462)	(7,569)	(2,981)
Intersegment eliminations	(4)	(2)	(14)

#### Total income from continuing operations before change in accounting principle

<b>\$ 57,249</b>	<b>\$ 56,481</b>	<b>\$ 58,138</b>
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## 24 Acquisitions

On October 1, 2002, the Company entered into a definitive merger agreement to acquire the Denver-based Mallon Resources Corporation. On March 10, 2003, the Company completed this acquisition. The total cost of the transaction was approximately \$51.2 million. The total cost of the transaction includes \$30.5 million for the October 2002 acquisition of Mallon's debt to Aquila Energy Capital Corporation and the settlement of outstanding hedges, and approximately \$8.4 million, which the Company loaned to Mallon prior to completion of the acquisition. Mallon shareholders received 0.044 of a share of the Company's common stock for each share of Mallon, which was equivalent to 481,509 shares of Black Hills Corporation common stock.

The acquisition was accounted for under the purchase method of accounting and, accordingly, the purchase price was allocated to the acquired assets and liabilities based on estimates of the fair values of the assets purchased and liabilities assumed as of the date of acquisition. The purchase allocation has been adjusted to reflect the completion of the quantification and analysis of the acquired asset retirement obligations in accordance with SFAS 143. This adjustment resulted in a \$0.7 million increase to Long-term liabilities and Property, plant and equipment. The adjusted allocation of the purchase price is as follows (in thousands):

Current assets	\$ 165
Property, plant and equipment	56,283
Deferred tax asset	5,194
Total assets acquired	\$ 61,642
Current liabilities	\$ 6,343
Long-term liabilities	4,146
Total liabilities assumed	\$ 10,489
Net assets	\$ 51,153

The results of operations of the above acquired company have been included in the accompanying consolidated financial statements since the acquisition date.

The following pro forma consolidated results of operations for the years ended December 31, have been prepared as if the Mallon acquisition had occurred on January 1, 2002 (in thousands):

	2003	2002
Operating revenues	\$1,252,991	\$ 919,538
Income from continuing operations	\$ 56,033	\$ 52,539
Net income available for common	\$ 60,516	\$ 55,630
Earnings per share -		
Basic:		
Continuing operations	\$ 1.80	\$ 1.92
Total	\$ 1.95	\$ 2.04
Diluted:		
Continuing operations	\$ 1.78	\$ 1.90
Total	\$ 1.93	\$ 2.02

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

Mallon Resources' proved developed and undeveloped reserves, estimated using constant year-end product prices, as of December 31, 2002, were approximately 86 billion cubic feet of gas equivalent. These estimates are based on reserve reports by Ralph E. Davis Associates, Inc., an independent engineering firm selected by the Company. The reserves are located primarily on the Jicarilla Apache Nation in the San Juan Basin of New Mexico and are comprised almost entirely of natural gas in shallow sand formations. The oil and gas leases of the acquisition total more than 66,500 gross acres (56,000 net), most of which is contained in a contiguous block that is in the early stages of development.

## 25 Subsequent Events

### CHEYENNE ACQUISITION

On January 13, 2004, the Company entered into a Stock Purchase Agreement to acquire from Xcel Energy, Inc. all of the outstanding capital stock of its subsidiary, CLF&P, a Wyoming corporation. On January 21, 2005, the Company completed this acquisition. The Company purchased all the common stock of CLF&P, including the assumption of outstanding debt of approximately \$25 million, for approximately \$90 million, plus a working capital adjustment to be finalized in the second quarter of 2005.

Cheyenne serves approximately 38,000 electric and 31,000 natural gas customers in Cheyenne and other parts of Laramie County, Wyoming. Its electric system peak load is 163 megawatts and power is supplied to the utility under an all-requirements contract with Public Service Company of Colorado, a subsidiary of Xcel Energy. The all-requirements contract expires in 2007. Annual gas distribution and transportation is approximately 5.0 million MMBtu.

### POWER SALES AGREEMENT

The Company, through its subsidiary BHP, has entered into an agreement with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., to provide wholesale power for the City of Sheridan, Wyoming. Under the agreement, the Company will provide all requirements up to 74 megawatts of power to Montana-Dakota from January 1, 2007 through January 1, 2017. Power requirements above 74 megawatts are negotiable under terms specified in the agreement. The contract is pending approval by the Wyoming Public Service Commission. An existing contract provides up to 55 megawatts and expires January 1, 2007.



## 26 Oil and Gas Reserves and Related Financial Data (Unaudited)

Black Hills Exploration and Production has interests in 996 oil and gas properties in ten states and also holds leases on approximately 256,000 net acres.

### COSTS INCURRED

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

	2004	2003	2002
Acquisition of properties:			
Proved	\$ 1,578	\$ 21,075	\$ 162
Unproved	231	19,994	2,331
Exploration costs	6,094	4,089	2,367
Development costs	39,258	19,377	11,699
Company's share of equity method investees' costs of property acquisition, exploration and development	392	1,067	-
	\$ 47,553	\$ 65,602	\$ 16,559

### RESERVES

The following table summarizes Black Hills Exploration and Production's quantities of proved developed and undeveloped oil and natural gas reserves, estimated using constant year-end product prices, as of December 31, 2004, 2003 and 2002, and a reconciliation of the changes between these dates. These estimates are based on reserve reports by Ralph E. Davis Associates, Inc., an independent engineering company selected by the Company. Such reserve estimates are based upon a number of variable factors and assumptions, which may cause these estimates to differ from actual results.

(in thousands of barrels of oil and MMcf of gas)	2004	
	Oil	Gas
Proved developed and undeveloped reserves:		
Balance at beginning of year	5,389	124,062
Production	(432)	(9,456)
Additions	685	65,965
Property sales	(39)	(1,698)
Revisions to previous estimates	(364)	(36,890)
Balance at end of year	5,239	141,983
Proved developed reserves at end of year included above	4,608	80,366
Year-end prices (NYMEX)	\$ 43.45	\$ 6.15
Year-end prices (average well-head)	\$ 41.19	\$ 5.55

(continued in next column)

(continued from previous column)	2003	
(in thousands of barrels of oil and MMcf of gas)	Oil	Gas
Proved developed and undeveloped reserves:		
Balance at beginning of year	4,880	28,513
Production	(405)	(8,548)
Additions	364	91,736
Property sales	-	-
Revisions to previous estimates	550	12,361
Balance at end of year	5,389	124,062
Proved developed reserves at end of year included above	4,830	66,294
Year-end prices (NYMEX)	\$ 32.52	\$ 6.19
Year-end prices (average well-head)	\$ 30.56	\$ 4.63

	2002	
	Oil	Gas
Proved developed and undeveloped reserves:		
Balance at beginning of year	4,055	24,071
Production	(455)	(4,707)
Additions	188	8,504
Property sales	(11)	-
Revisions to previous estimates	1,103	645
Balance at end of year	4,880	28,513
Proved developed reserves at end of year included above	4,188	27,473
Year-end prices (NYMEX)	\$ 31.20	\$ 4.60
Year-end prices (average well-head)	\$ 29.24	\$ 3.41

The 2004 reserve reconciliation reflected a 36.8 BCF downward revision to previous estimates. Approximately 70 percent of the revision is associated with our East Blanco Field in New Mexico. Since acquiring the field in March 2003, we have undertaken an extensive drilling and recompletion program. Overall, results of this development program have resulted in substantial reserve additions from numerous producing formations. However, our estimates for Proved Developed Non-Producing (PNP) and Proved Developed Behind Pipe (PBP) reserves, particularly in the multiple horizons of the Tertiary and Pictured Cliff zones, were revised downward based on actual results from our drilling and completion activities. In addition, many well locations which had been booked as Proved Undeveloped (PUD) and Proved Developed Non-Producing (PNP) in last year's reserve study were reclassified through drilling and completion activities to Proved Developed Producing (PDP) status by year-end 2004. Based on actual production history at the reclassified properties, reserve estimates for some well locations were revised downward.

The remaining 30 percent of downward reserve revisions were the result of various routine changes to engineering estimates, primarily due to additional production history.

## CAPITALIZED COSTS

Following is information concerning capitalized costs for the years ended December 31, (in thousands):

	2004	2003	2002
Unproved oil and gas properties	\$ 20,148	\$ 22,705	\$ 5,109
Proved oil and gas properties	209,748	162,116	111,227
	229,896	184,821	116,336
Accumulated depreciation, depletion & amortization and valuation allowances	(75,870)	(61,928)	(56,488)
Net capitalized costs	\$ 154,026	\$ 122,893	\$ 59,848
Company's share of equity method investees' net capitalized costs	\$ 1,459	\$ 1,067	\$ -

## RESULTS OF OPERATIONS

Following is a summary of results of operations for producing activities for the years ended December 31, (in thousands):

	2004	2003	2002
Revenues			
Sales	\$ 57,869	\$ 43,458	\$ 23,291
Production costs	19,991	14,432	6,310
Depreciation, depletion & amortization and valuation provisions	11,497	9,331	7,246
	31,488	23,763	13,556
Income tax expenses	5,342	3,953	1,668
Results of operations from producing activities (excluding corporate overhead and interest costs)	\$ 21,039	\$ 15,742	\$ 8,067
Company's share of equity method investees' results of operations for producing activities	\$ (120)	\$ 337	\$ -

## 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):

	2004	2003	2002
Future cash inflows	\$1,044,098	\$ 794,555	\$ 274,900
Future production and development costs	(409,478)	(339,732)	(124,451)
Future income tax expenses	(144,053)	(129,538)	(41,546)
Future net cash flows	490,567	325,285	108,903
10 percent annual discount for estimated timing of cash flows	(181,368)	(123,163)	(36,585)
Standardized measure of discounted future net cash flows	\$ 309,199	\$ 202,122	\$ 72,318

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):

	2004	2003	2002
Standardized measure – beginning of year	\$ 202,122	\$ 72,318	\$ 38,876
Sales and transfers of oil and gas produced, net of production costs	(45,266)	(29,026)	(16,981)
Net changes in prices and production costs	55,916	51,735	33,285
Extensions, discoveries and improved recovery, less related costs	168,516	9,064	15,700
Net changes in future development costs	21,852	32,757	2,202
Revisions of previous quantity estimates	(96,419)	26,632	11,839
Accretion of discount	26,534	9,417	4,375
Net change in income taxes	(22,028)	(41,372)	(16,978)
Purchases of reserves	4,062	70,597	-
Sales of reserves	(6,090)	-	-
Standardized measure – end of year	\$ 309,199	\$ 202,122	\$ 72,318

## 27 Quarterly Historical Data (Unaudited)

The Company operates on a calendar year basis. The following table sets forth selected unaudited historical operating results and market data for each quarter of 2004 and 2003.

### 2004

(in thousands, except per share amounts, dividends and common stock prices)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating revenues	\$ 274,328	\$ 280,355	\$ 279,614	\$ 287,404
Operating income	28,306	27,274	37,313	41,026
Income from continuing operations	9,994	9,552	17,348	20,355
(Loss) income from discontinued operations, net of taxes	(208)	1,963	(168)	(863)
Net income	9,786	11,515	17,180	19,492
Net income available for common stock	9,698	11,437	17,102	19,415
Earnings per common share:				
Basic -				
Continuing operations	\$ 0.31	\$ 0.29	\$ 0.53	\$ 0.63
Discontinued operations	(0.01)	0.06	-	(0.03)
Total	\$ 0.30	\$ 0.35	\$ 0.53	\$ 0.60
Diluted -				
Continuing operations	\$ 0.30	\$ 0.29	\$ 0.53	\$ 0.62
Discontinued operations	-	0.06	(0.01)	(0.03)
Total	\$ 0.30	\$ 0.35	\$ 0.52	\$ 0.59
Dividends paid per share	\$ 0.31	\$ 0.31	\$ 0.31	\$ 0.31
Common stock prices				
High	\$ 32.17	\$ 32.49	\$ 31.60	\$ 31.68
Low	\$ 29.19	\$ 27.83	\$ 26.52	\$ 27.85

### 2003

(in thousands, except per share amounts, dividends and common stock prices)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating revenues	\$ 291,445	\$ 289,243	\$ 410,860	\$ 258,502
Operating income	35,504	30,330	39,044	26,290
Income from continuing operations before changes in accounting principles	15,698	13,507	17,673	9,603
Income from discontinued operations, net of taxes	1,160	3,153	4,771	852
Net income	14,178	16,660	22,444	7,940
Net income available for common stock	14,121	16,603	22,387	7,853
Earnings per common share:				
Basic -				
Continuing operations	\$ 0.58	\$ 0.44	\$ 0.55	\$ 0.29
Discontinued operations	0.04	0.10	0.15	0.03
Changes in accounting principles	(0.10)	-	-	(0.08)
Total	\$ 0.52	\$ 0.54	\$ 0.70	\$ 0.24
Diluted -				
Continuing operations	\$ 0.58	\$ 0.43	\$ 0.54	\$ 0.29
Discontinued operations	0.04	0.10	0.15	0.03
Changes in accounting principles	(0.10)	-	-	(0.08)
Total	\$ 0.52	\$ 0.54	\$ 0.69	\$ 0.24
Dividends paid per share	\$ 0.30	\$ 0.30	\$ 0.30	\$ 0.30
Common stock prices				
High	\$ 28.39	\$ 31.70	\$ 33.54	\$ 33.15
Low	\$ 21.85	\$ 27.00	\$ 29.82	\$ 27.76

## Selected Financial Statistics

Years ended December 31,	2004	2003	2002	2001	2000
<b>TOTAL ASSETS (in thousands)</b>	\$2,056,163	\$2,063,252	\$1,999,974	\$1,651,765	\$1,252,936
<b>PROPERTY, PLANT AND EQUIPMENT</b> (in thousands)					
Total property, plant and equipment	\$1,971,119	\$1,882,545	\$1,703,220	\$1,377,521	\$ 911,147
Accumulated depreciation and depletion	525,387	440,274	377,568	297,400	252,816
Capital expenditures	90,974	116,691	303,191	594,142	173,517 <sup>(a)</sup>
<b>CAPITALIZATION (in thousands)</b>					
Long-term debt, net of current maturities	\$ 733,581	\$ 868,459	\$ 540,958	\$ 329,771	\$ 213,606
Preferred stock equity	7,167	8,143	5,549	5,549	4,000
Common stock equity	728,598	701,604	529,614	509,615	278,346
Total capitalization	\$1,469,346	\$1,578,206	\$1,076,121	\$ 844,935	\$ 495,952
<b>CAPITALIZATION RATIOS</b>					
Long-term debt, net of current maturities	49.9%	55.0%	50.3%	39.0%	43.1%
Preferred stock equity	0.5	0.5	0.5	0.7	0.8
Common stock equity	49.6	44.5	49.2	60.3	56.1
Total	100.0%	100.0%	100.0%	100.0%	100.0%
<b>TOTAL OPERATING REVENUES</b> (in thousands)	\$1,121,701	\$1,250,050 <sup>(b)</sup>	\$ 908,477	\$ 737,806	\$ 741,121
<b>INCOME FROM CONTINUING OPERATIONS BEFORE CHANGE IN ACCOUNTING PRINCIPLE (in thousands)</b>	\$ 57,249	\$ 56,481	\$ 58,138	\$ 84,355	\$ 52,480
<b>DIVIDENDS PAID ON COMMON STOCK</b> (in thousands)	\$ 40,210	\$ 37,025	\$ 31,116	\$ 28,517	\$ 23,527
<b>COMMON STOCK DATA</b> (in thousands)					
Shares outstanding, average	32,387	30,496	26,803	25,374	22,118
Shares outstanding, average diluted	32,912	31,015	27,167	25,771	22,281
Shares outstanding, end of year	32,478	32,298	26,933	26,652	22,921
(in dollars)					
Basic earnings per average share –					
Continuing operations	\$ 1.76	\$ 1.84	\$ 2.16	\$ 3.30	\$ 2.37
Discontinued operations	0.02	0.33	0.09	0.15	0.02
Change in accounting principle	-	(0.17)	0.03	-	-
Total	\$ 1.78	\$ 2.00	\$ 2.28	\$ 3.45	\$ 2.39
Diluted earnings per average share –					
Continuing operations	\$ 1.74	\$ 1.82	\$ 2.14	\$ 3.28	\$ 2.35
Discontinued operations	0.02	0.32	0.09	0.14	0.02
Change in accounting principle	-	(0.17)	0.03	-	-
Total	\$ 1.76	\$ 1.97	\$ 2.26	\$ 3.42	\$ 2.37
Dividends paid per share	\$ 1.24	\$ 1.20	\$ 1.16	\$ 1.12	\$ 1.08
Book value per share, end of year	\$ 22.43	\$ 21.72	\$ 19.66	\$ 19.12	\$ 12.14
<b>RETURN ON AVERAGE COMMON STOCK EQUITY</b>	8.1%	9.9%	11.8%	22.2%	21.3%

(a) Excludes the non-cash acquisition of Indeck Capital, Inc.

(b) Includes \$114.0 million of contract termination revenue.



## Selected Operation Statistics (unaudited)

Years ended December 31,	2004	2003	2002	2001	2000
<b>WHOLESALE ENERGY</b>					
Coal production (in thousands)					
Tons of coal produced and sold	4,780	4,812	4,052	3,518	3,050
Coal reserves – tons	294,235	262,650	272,794	276,648	274,667
Exploration and production reserves (in thousands)					
Oil – barrels	5,239	5,389	4,880	4,055	4,413
Gas – Mcf	141,983	124,062	28,513	24,071	18,404
Total Mcfe reserves	173,417	156,399	57,793	48,401	44,882
Net present value (PV-10 method)	\$ 394,446	\$ 265,341	\$ 94,165	\$ 43,745	\$ 111,451
Production (in thousands)					
Oil – barrels	432	416	453	446	334
Gas – Mcf	10,000	8,348	4,683	4,619	3,274
Total Mcfe	12,595	10,843	7,398	7,293	5,278
Wells					
Wells – operated	516	514	384	385	298
Wells – nonoperated	480	509	440	428	341
	996	1,023	824	813	639
Drilled – gross	127	82	52	81	63
Drilled – net	43	23	12	19	11
Fuel marketing average daily volumes					
Natural gas physical sales – MMBtus	1,226,600	897,850	683,500	543,000	567,900
Natural gas financial sales – MMBtus	514,500	344,050	404,700	504,700	292,900
Crude oil marketed – barrels	44,900	58,700	57,200	36,500	44,300
Power generation					
Operating Nameplate MWs					
Coal-fired <sup>(b)</sup>	90	90	-	-	-
Natural gas-fired <sup>(c)</sup>	885	884	884 <sup>(a)</sup>	553	171
Hydroelectric <sup>(d)</sup>	-	-	42	40	39
Equity investment, various types	29	28	24	24	40
	1,004	1,002	950	617	250
Under construction MWs, net ownership:					
Natural gas-fired	-	-	-	274	380
Coal-fired <sup>(b)</sup>	-	-	90	90	90
	-	-	90	364	470

(a) Includes the 224 MW expansion at the Las Vegas cogeneration power plant which went into service on January 3, 2003.

(b) Includes plant under a lease arrangement.

(c) Includes 40 MW in 2004, 2003 and 2002, 28 MW in 2001 and 19 MW in 2000 currently reported as “discontinued operations.”

(d) These assets were sold in September 2003 and are reported as “discontinued operations.”

## Selected Operation Statistics (continued, unaudited)

Years ended December 31,	2004	2003	2002	2001	2000
<b>ELECTRIC UTILITY</b>					
Electric utility electricity generated and purchased (megawatthours)					
Generated, net station output	1,781,518	1,963,147	2,072,545	2,270,470	2,122,766
Purchased and net interchange	1,361,409	1,048,076	952,965	760,727	620,958
Total, generated and purchased	3,142,927	3,011,223	3,025,510	3,031,197	2,743,724
Company use and losses	(92,131)	(85,698)	(79,773)	(53,813)	(86,280)
	3,050,796	2,925,525	2,945,737	2,977,384	2,657,444
Electric utility electricity sales (megawatthours)					
Residential	447,166	463,290	454,201	430,916	415,761
General and commercial	627,326	641,779	620,665	602,713	582,761
Industrial	406,209	404,341	413,930	508,856	510,053
Public authorities	28,934	27,426	26,839	25,968	25,484
Sales for resale	450,334	457,983	450,425	443,901	439,007
Total firm electricity sales	1,959,969	1,994,819	1,966,060	2,012,354	1,973,066
Non-firm sales	1,090,827	930,706	979,677	965,030	684,378
	3,050,796	2,925,525	2,945,737	2,977,384	2,657,444
Electric utility revenue (in thousands)					
Residential	\$ 36,536	\$ 37,716	\$ 37,111	\$ 35,183	\$ 34,140
General and commercial	46,791	47,777	46,673	45,007	43,860
Industrial	19,796	19,589	20,407	24,014	24,234
Public authorities	2,200	2,102	2,070	2,014	1,994
Sales for resale	17,359	17,458	17,017	16,399	15,969
Total firm electricity revenue	122,682	124,642	123,278	122,617	120,197
Non-firm electric revenue	43,589	37,736	31,945	84,891	47,574
Other electric revenue	7,474	8,641	6,963	4,847	5,537
	\$ 173,745	\$ 171,019	\$ 162,186	\$ 212,355	\$ 173,308
Electric utility customers (end of year)					
Residential	50,760	49,848	48,889	48,436	47,974
General and commercial	11,301	11,107	10,874	10,611	10,431
Industrial	45	45	42	45	47
Public authorities	151	146	141	143	147
Other electric utilities	2	2	2	2	2
	62,259	61,148	59,948	59,237	58,601
Degree days	7,075	7,956	7,972	7,682	8,005
<b>COMMUNICATIONS</b>					
Communications revenue (in thousands)					
Residential	\$ 22,105	\$ 21,979	\$ 19,437	\$ 12,072	\$ 4,490
Business	10,477	9,119	8,600	5,512	2,287
Other	7,004	8,665	4,640	2,674	912
	\$ 39,586	\$ 39,763	\$ 32,677	\$ 20,258	\$ 7,689
Residential customers	23,663	23,878	21,700	15,660	8,368
Revenue generating units <sup>(a)</sup>	56,835	53,568	48,285	32,484	16,634
Business customers	3,317	3,012 <sup>(b)</sup>	3,061	2,250	646
Hybrid fiber-coaxial cable (miles)	845	840	818	737	588

(a) Total Revenue generating units (RGU) equal the total number of services to which residential customers subscribe. Telephone, cable TV and Internet access each represent an RGU.

(b) In 2003, reported business customers were adjusted for the consolidation of multiple-location business customers, business orders and temporary business access lines.

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## **Board of Directors**



### **DANIEL P. LANDGUTH**

Daniel P. Landguth, age 58, has been Chairman of the Board since January 2004. He served as Chairman of the Board and Chief Executive Officer from January 1991 to January 2004. Mr. Landguth has 35 years of experience with Black Hills Corporation. He has been a member of the Board of Directors since 1989 and currently chairs the Executive Committee. Mr. Landguth holds a B.S. degree in Electrical Engineering from the South Dakota School of Mines and Technology.



### **DAVID R. EMERY**

David R. Emery, age 42, was elected President, Chief Executive Officer and a member of the Board of Directors in January 2004. He served as 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. From June 1993 to January 1997, he was General Manager of Black Hills Exploration and Production, Inc. Mr. Emery has 16 years of experience with the Company. He was previously employed as a petroleum engineer for a large independent oil and gas company. He holds a B.S. degree in Petroleum Engineering from the University of Wyoming and a M.B.A. from the University of South Dakota.



### **BRUCE B. BRUNDAGE**

Bruce B. Brundage, age 69, has been President and Director of Brundage & Company, since 1973. Brundage & Company is a Colorado-based firm providing financial and advisory services to business concerns primarily located in the western United States. Mr. Brundage has been a member of the Board of Directors since 1986 and currently chairs the Audit Committee.



### **DAVID C. EBERTZ**

David C. Ebertz, age 59, is President of Dave Ebertz Risk Management Consulting, a firm specializing in insurance and risk management services for schools and public entities, since January 2000. From 1976 until December 1999, he was President and majority owner at Barlow Agency, Inc., Gillette, Wyoming, providing risk management and insurance services primarily to the manufacturing, oil and gas, and mining industries. Mr. Ebertz has served on the Board of Directors since 1998.



### **JACK W. EUGSTER**

Jack W. Eugster, age 59, is the Non-Executive Chairman of Shopko Stores, Inc., a general merchandise discount store chain since 2001. He was Chairman, CEO and President of Musicland Stores, Inc. from 1986 to 2001. Mr. Eugster was elected to the Board of Directors in May 2004.

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## JOHN R. HOWARD

John R. Howard, age 64, 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 serves as Lead Director and chairs the Governance Committee.



## KAY S. JORGENSEN

Kay S. Jorgensen, age 54, is involved in numerous business activities and is owner of Jorgensen-Thompson Creative Broadcast Services, Inc., providing radio broadcast services in the western United States. Previously, she served in the South Dakota State Legislature for several terms and has served on various regional, state and local boards and commissions. Ms. Jorgensen has served on the Board of Directors since 1992.



## RICHARD KORPAN

Richard Korpan, age 63, retired, was Chairman of the Board and Chief Executive Officer of Florida Progress Corporation and its predecessor from 1991 to 2000. Mr. Korpan was elected to the Board of Directors in June 2003.



## STEPHEN D. NEWLIN

Stephen R. Newlin, age 52, is President of the Industrial Sector of Ecolab, Inc. (NYSE:ECL). Ecolab is a provider of cleaning, sanitizing, food safety, chemicals and equipment serving industrial, institutional, healthcare, food and beverage industries, since 2003. Prior to that, Mr. Newlin was a private investor and business advisor from 2001 to 2003 and was President, Chief Operating Officer and Director of Nalco Chemical Company from 1998 to 2001. Mr. Newlin was elected to the Board of Directors in January 2004.



## THOMAS J. ZELLER

Thomas J. Zeller, age 57, has been President of RESPEC, a technical consulting and services firm with expertise in engineering, environmental and information technologies, since 1995. Mr. Zeller has been a member of the Board of Directors since 1997 and currently chairs the Compensation Committee.





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## Corporate officers



### DAVID R. EMERY

David R. Emery, age 42, was elected President, Chief Executive Officer and a member of the Board of Directors in 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. From June 1993 to January 1997, he was General Manager of Black Hills Exploration and Production. Mr. Emery has 16 years of experience with Black Hills. He was previously employed as a petroleum engineer for a large independent oil and gas company. He holds a B.S. in Petroleum Engineering from the University of Wyoming and a M.B.A. from the University of South Dakota.



### THOMAS M. OHLMACHER

Thomas M. Ohlmacher, age 53, has been the President and Chief Operating Officer of our Wholesale 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 holds a B.S. in Chemistry from the South Dakota School of Mines and Technology.



### LINDEN R. EVANS

Linden R. Evans, age 42, was appointed President and Chief Operating Officer – Retail Services in October 2004. Mr. Evans had been serving as our Vice President and General Manager of our communications subsidiary since December 2003, and served as our Associate Counsel from May 2001 to December 2003. Prior to joining Black Hills, Mr. Evans was an attorney for several law firms, including the law firm Truhe, Beardsley, Jensen, Helmers and VonWald from February 1997 to May 2001. He was also employed as a mining engineer with several gold mining companies. He holds a J.D. from the Northwestern School of Law, Lewis & Clark College, Portland, Oregon, and a B.S. Degree in Mining Engineering from the University of Missouri.



### MARK T. THIES

Mark T. Thies, age 41, has been our Executive Vice President and Chief Financial Officer since March 2000. From May 1997 to March 2000, he was our Controller. From 1990 to 1997, Mr. Thies served in a number of accounting positions with InterCoast Energy Company, an unregulated energy company and a wholly owned subsidiary of MidAmerican Energy Holdings Company. Mr. Thies holds a B.A. in Accounting and a B.A. in Business Administration from Saint Ambrose College and is a Certified Public Accountant.



### RUSSELL L. COHEN

Russell L. Cohen, age 44, has been Senior Vice President and Chief Risk Officer since May 2002. Prior to joining Black Hills, Mr. Cohen was General Partner and Chief Financial Officer at Regensis Group, LLC from December 2000 to April 2002. He was Chief Financial Officer at Worldbridge Broadband Services, Inc. from January 1998 to February 2000, when it was acquired, and left in November 2000. He worked in various derivative products positions at First Boston, Lehman Brothers and Bear Stearns from June 1987 to December 1997. Mr. Cohen holds a B.S. in Economics from Yale University and an M.B.A. from Stanford.



### STEVEN J. HELMERS

Steven J. Helmers, age 48, 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. Prior to joining Black Hills, Mr. Helmers was an attorney and a shareholder with the Rapid City, South Dakota law firms of Truhe, Beardsley, Jensen, Helmers & VonWald, from 1997 to January 2001, and Lynn, Jackson, Shultz & Lebrun, P.C., from 1983 to 1997. He holds a J.D. from the University of South Dakota School of Law.

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#### MAURICE T. KLEFEKER

Maurice T. Klefeker, age 48, was elected Senior Vice President – Strategic Planning and Development in March 2004. Prior to that, he served as Senior Vice President of our subsidiary, Black Hills Generation, Inc. from September 2002 to March 2004 and as Vice President of Corporate Development from July 2000 to September 2002. He joined Indeck Capital, Inc. in December 1995 as Asset Manager and later served as Vice President of Business Development until July 2000. Prior to that, he served in a variety of technical and engineering positions with Northern Indiana Public Service Company for 14 years. Mr. Klefeker holds a B.S. from Purdue University and a M.B.A. from the University of Notre Dame.



#### JAMES M. MATTERN

James M. Mattern, age 50, has been the Senior Vice President – Corporate Administration and Compliance since April 2003, Senior Vice President – Corporate Administration from September 1999 to April 2003, and was Vice President – Corporate Administration from January 1994 to September 1999. Mr. Mattern has 17 years of experience with Black Hills. He holds a B.S. in Social Sciences and an M.S. in Administration from Northern State University.



#### GARNER M. ANDERSON

Garner M. Anderson, age 42, has been our Vice President and Treasurer since July 2003. Mr. Anderson has over 17 years of experience with Black Hills, including positions as Director – Treasury Services and Risk Manager. Mr. Anderson holds a B.S. in Business Administration from the University of South Dakota and an M.B.A. in Finance from Arizona State University, and is a Certified Public Accountant.



#### ROXANN R. BASHAM

Roxann R. Basham, age 43, was elected Vice President – Governance and Corporate Secretary in February 2004. Prior to that, she was our Vice President – Controller from March 2000 to January 2004. From December 1997 to March 2000, she was Vice President – Finance and Secretary/Treasurer. From 1993 until December 1997, she served as our Secretary/Treasurer, and has a total of 21 years of experience with Black Hills. She holds a B.S. in Business Administration from the University of South Dakota and is a Certified Public Accountant.



#### PERRY S. KRUSH

Perry S. Krush, age 46, was appointed Vice President – Controller in December 2004. Mr. Krush has over 16 years of experience with Black Hills, including positions as Controller – Retail Operations from 2003 to 2004, Director of Accounting for our Subsidiary, Black Hills Energy Inc. and Accounting Manager – Fuel Resources from 1997 to 2003. He previously held positions in healthcare administration and public accounting. Mr. Krush holds a B.S. in Business Administration from the University of South Dakota.



#### KYLE D. WHITE

Kyle D. White, age 45, has been Vice President – Corporate Affairs since January 30, 2001 and Vice President – Marketing and Regulatory Affairs since July 1998. Mr. White served as Director – Strategic Marketing and Sales from 1993 to January 1998 and Vice President-Energy Services from January 1998 to July 1998. He has a total of 22 years of experience with Black Hills. Mr. White holds a B.S. and M.S. in Business Administration from the University of South Dakota.





#### COMMON STOCK

Transfer Agent, Registrar  
& Dividend Disbursing Agent  
Wells Fargo Shareowner Services  
P.O. Box 64854  
St. Paul, Minnesota 55164-0854  
800-468-9716

#### SENIOR UNSECURED NOTES

Trustee & Paying Agent  
LaSalle Bank N.A.  
135 S. LaSalle Street, Suite 1840  
Chicago, Illinois 60603

#### FIRST MORTGAGE BONDS

Trustee & Paying Agent  
JPMorgan Chase Bank  
450 West 33rd Street  
New York, New York 10001

#### POLLUTION CONTROL REFUNDING

Revenue Bonds  
Trustee & Paying Agent  
Wells Fargo Bank, N.A.  
Sixth Street and Marquette Avenue  
Minneapolis, Minnesota 55479

#### ENVIRONMENTAL IMPROVEMENT

Revenue Bonds  
Trustee & Paying Agent  
JPMorgan Institutional Trust Services  
131 South Dearborn, 8th Floor  
Chicago, Illinois 60670

#### CORPORATE OFFICES

Black Hills Corporation  
P.O. Box 1400  
625 Ninth Street  
Rapid City, South Dakota 57709  
605-721-1700  
www.blackhillscorp.com

#### MARKET FOR EQUITY SECURITIES

The Company's Common Stock (\$1 par value) is traded on the New York Stock Exchange (NYSE). The Company has filed its CEO Certification with the NYSE. Quotations for the Common Stock are reported under the symbol BKH. At year-end, the Company had 5,500 shareholders of record. All fifty states and the District of Columbia plus 16 foreign countries are represented.

The continued interest and support of equity owners is appreciated. The Company has declared Common Stock dividends payable in each year since its incorporation in 1941. At its February 2005 meeting, the Board of Directors raised the quarterly dividend to 32.0 cents per share, equivalent to an annual increase of 4.0 cents per share. This regular quarterly dividend is payable March 1, 2005. Dividend payment dates are normally March 1, June 1, September 1 and December 1.

#### 2005 ANNUAL MEETING

The Annual Meeting of Shareholders will be held at The Journey Museum, 222 New York Street, Rapid City, South Dakota, at 9:30 a.m. local time on May 25, 2005. Prior to the meeting, formal notice, proxy statement and proxy will be mailed to shareholders.

#### DIRECT DEPOSIT OF DIVIDENDS

The Company encourages you to consider the direct deposit of your dividends. With direct deposit, your quarterly dividend payment can be automatically transferred on the dividend payment date to the bank, savings and loan, or credit union of your choice. Direct deposit assures payments are credited to shareholders' accounts without delay. A form is attached to your dividend check where you can request information about this method of payment. Questions regarding direct deposit should be directed to Wells Fargo Shareowner Services.

#### DIVIDEND REINVESTMENT PLAN

A Dividend Reinvestment and Stock Purchase Plan (the Plan) is available to common shareholders. The Plan provides a method of investing common stock dividends and optional cash payments in additional shares of Common Stock of the Company at 100 percent of the recent average market price. Participants may elect to continue to receive cash dividends on shares registered in their names and invest by making optional cash payments only. Questions regarding the Plan should be directed to Wells Fargo Shareowner Services.

The Company reports details concerning its operation and other matters periodically to the Securities and Exchange Commission on Form 8-K, Form 10-Q and Form 10-K, which are available on written request to: Investor Relations, Black Hills Corporation, P.O. Box 1400, Rapid City, South Dakota, 57709. The Company's CEO/CFO Section 302 Certifications have been filed on exhibits to its Form 10-K. The Company also has available through our internet website at [www.blackhillscorp.com](http://www.blackhillscorp.com) its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after the Company electronically files such material with, or furnishes it to, the Securities and Exchange Commission.



In addition, the Company has certain corporate governance documents on our website. These documents include a Code of Ethics that applies to its CEO, CFO and key finance/accounting employees, Corporate Governance Guidelines for its Board of Directors, Code of Business Conduct for its employees, and charters for the Executive, Audit, Compensation and Governance Committees of the Board of Directors.



