BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO.	)))))))	CASE NO. IPC-E-03-13

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

J. LAMONT KEEN

Q. Please state your name and business address.

A. My name is J. LaMont Keen and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. What is your position at Idaho Power Company?

A. I am the President and Chief Operating Officer.

Q. What is your educational background?

A. I graduated magna cum laude in 1974 from the College of Idaho in Caldwell, Idaho now called Albertson College of Idaho, receiving a Bachelor of Business Administration Degree in Accounting. In 1994 I completed the Advanced Management Program at the Harvard University Graduate School of Business. I have also attended many utility management-training programs, including the Stone & Webster Utility Management Development Program, the University of Idaho Public Utilities Executive's Course and the Edison Electric Institute Executive Leadership Program.

Q. Please outline your business experience.

A. I have worked in the electric utility industry at Idaho Power Company for nearly 30 years, beginning my employment in 1974 in the accounting department. I advanced through several accounting, analyst and management positions and in July 1988, I was promoted to Controller. In November 1991 I was appointed to Vice President of Finance and Chief Financial Officer and served in that capacity until March of 1999 when I was also given responsibility for all of the administrative areas of the Company as Senior Vice President of Administration and Chief Financial Officer. In March of 2002, I was appointed President and Chief Operating Officer where I have responsibility for the Company's operating units. I either have or have had responsibility for virtually all aspects of the Company's operations at some point in my career.

Q. What are your duties as President and Chief Operating Officer of Idaho Power Company?

A. I am responsible for the general oversight of all the utility operations including all power supply and delivery activities.

Q. What is the purpose of your testimony?

A. As Idaho Power Company's president, I am testifying as to policy matters related to the Company's filing of this request for general rate relief. Specifically, I will address the events and circumstances that led to this rate application, including an overview of significant events, both regulatory and otherwise, that have occurred over the last decade; the impact of ten years of growth on our utility system; the Company's stewardship of the system during the recent difficult period; the increasing emphasis on system reliability; the critical demand for investments in infrastructure; and the cash flow and earnings implications to the Company of managing through all of the above.

Q. Please describe the Company's last general rate increase in Idaho.

A. The Company's last general rate case, Case No. IPC-E-94-5, concluded on January 1, 1995 when the Idaho Public Utilities Commission (IPUC or the Commission) issued Order No. 25880 authorizing Idaho Power to increase its rates by $17,177,048 or 4.19 percent. In that case, the rate of return on common equity was established at 11 percent with an overall rate of return at 9.199 percent. Permanent rate changes were implemented on February 1, 1995.

Shortly following the conclusion of Case No. IPC-E-94-5, the Company completed its upgrade of the Twin Falls hydroelectric power plant and filed an application with the Commission to supplement the results of Order No. 25880 with rate impacts of the new production facilities.

The Commission issued a bench ruling that allowed Idaho Power to increase its revenue requirement by $3,759,695 or .88 percent, to include the Twin Falls upgrade on August 14, 1995. On November 13, 1995, Order No. 26236 reaffirmed the Commission's bench ruling.

Q. Please describe the rate moratorium entered into following the last general rate case.

A. On October 20, 1995, in Order No. 26216, the

Commission approved a rate moratorium and stability of earnings stipulation between various intervenor parties, the Staff of the Commission, and Idaho Power Company. The stipulation provided that in the period from 1995 through 1999, any time the Company's return on equity (ROE) fell below 11.5 percent, the Company would be allowed to amortize an additional amount of Accumulated Deferred Investment Tax Credits (ADITC) in order to increase earnings back to the 11.5 percent level. If the Company's ROE exceeded 11.75 percent, the Company would refund (revenue share) 50 percent of the excess earnings to the benefit of its Idaho customers. The stipulation also provided that Base Rates would not change prior to January 1, 2000. Because of improved operating conditions, including hydro availability, the Company never had to use ADITC to supplement earnings during the moratorium. On the other hand, Idaho Power's customers were able to experience the benefits of revenue sharing during the years 1996, 1997, 1998, and 1999. The total benefit shared with the Idaho retail customers was approximately $28 million.

Q. Has the corporate structure changed at Idaho Power during the last ten years?

A. Yes. On October 1, 1998, with the formation of IDACORP, Inc., the Company became a part of a holding company structure. IDACORP, Inc. serves as the parent of Idaho Power Company, a regulated utility, as well as a number of unregulated subsidiaries. The purpose in forming IDACORP, Inc. was two-fold. First, the structure allowed Idaho Power to continue as a regulated utility just as it had for the past 82 years. At the same time, the creation of a holding company enabled present and future non-regulated business units to compete for business in the non-regulated arena without saddling the regulated utility with the capital requirements and risks of those ventures.

The move to a holding company structure followed approval by multiple regulators including the Idaho Commission in Order No. 27348 issued on January 29, 1998 in Case No. IPC-E-97-11.

Q. Following the rate moratorium, what impact did the Western energy crisis have on Idaho Power?

A. By the summer of 2001, the West was in the grip of the nation's worst energy crisis.

Increases in the price for natural gas, an increasingly important fuel for thermal generation of electricity in California, combined with the 2000-2001 water conditions that were among the lowest ever recorded in the Pacific Northwest region according to the U.S. Department of

Agriculture, created further upward pressure on wholesale prices emanating from the California market. Compared with the first quarter 2000, wholesale power prices for 2001 peak period transactions in the Pacific Northwest rose by almost a factor of ten, from an average of $25 per megawatt-hour to $240 per megawatt-hour as measured by the Dow-Jones Mid-Columbia Index. Price spikes took place on the hourly spot market that resulted in the price of electricity exceeding $1000 for short periods of time.

Idaho Power's operations were also adversely affected by the tremendous increase in prices for purchased power, increased demand, and reduced hydroelectric generation. This particular combination of economic and natural phenomena produced substantial increases in costs to supply power to customers not only in Idaho Power's service territory but also across the west. Large and small utilities throughout the west were filing for double digit rate increases on multiple occasions during the 18-month energy crisis. Idaho Power was no exception as its annual PCA rate applications increased to record amounts.

Q. Please describe the severity of the current Idaho drought.

A. Drought is of particular concern to a hydro-based utility. Reductions in the region's already limited water supply for extended periods of time can produce devastating impacts in terms of reduced hydro-generation availability and correlating higher energy costs. Drought is also a "creeping phenomenon" making its onset and end difficult to determine. The effects of drought accumulate slowly over a considerable period of time and may linger for years after the termination of the event. Current water supply conditions for Idaho demonstrate the reality of this phenomenon.

At its peak, the 2000 drought was as severe as any of the major droughts of the last 40 years as measured by temperature and moisture. This exceptionally dry summer resulted in low soil moisture entering into the winter. Precipitation was much below normal over most of the Pacific Northwest during the fall and winter of 2000-2001 and hydrologically, the evolving 2001 drought appeared to be similar in magnitude to the 1977 drought of record based on streamflow and reservoir levels.

In 2001, the water supply outlook for the state of Idaho remained much below normal and continued to be one of the lowest years on record. May 2001 runoff was estimated to be the second or third lowest on record for many sites across the state. Snowpack for the same period remained low at 30 to 55 percent of average across Idaho. The severity of the 2001 drought was further exacerbated by the ongoing

California power problems, one result of which was that the Federal System reservoirs were drafted to some of their lowest levels ever.

In 2002 and 2003, the entire Columbia River Basin experienced drought conditions. The Columbia River at The Dalles, Oregon, is a commonly used reference point to gauge flows in the Columbia River in the Pacific Northwest. In 2002 and 2003, the April through August flows at The Dalles averaged only 68 percent of average. These low flows significantly reduced the amount of surplus energy available for the Company to purchase.

In 2003, the creeping drought phenomenon continues. Over the past four years, the April through July inflow to Brownlee Reservoir has averaged about 60 percent of the 1960 through 2003 average. Even more telling, in southern Idaho the April through July flows at Swan Falls Dam have declined to 46 percent of average. In July 2003, the flow at Swan Falls Dam was at the lowest level recorded by either the USGS or Idaho Power. In response to these low flows, the Idaho Department of Water Resources was prepared to take the extreme measure of actually curtailing junior upstream surface water diversions.

Q. What effect does a severe drought have on the Company?

A. During drought, Idaho Power must rely more heavily on purchased power to meet system loads, usually at higher market prices due to supply scarcity. At the same time, there are obviously less "surpluses" to sell to offset increased market purchases. The result is upward pressure on the Company's power supply costs.

Q. How did the combination of drought and high market prices impact the Company's PCA requests?

A. Because Idaho Power relies predominantly upon hydroelectric generation to serve its load, the Company's actual costs of providing electricity can vary dramatically from year to year depending on changes in streamflow and market prices. In recognition of the fluctuating power supply costs associated with variable hydroelectric generation, the Commission approved a "Power Cost Adjustment" (PCA) mechanism for Idaho Power in 1993. During the years that the PCA has been in effect, there have been both annual credits and surcharges. However, as a result of the Western energy crisis and drought conditions, the Company's PCA application in 2001 was the largest amount ever requested. Following extended hearings, the Commission authorized the bulk of the $227.4 million requested under the PCA mechanism. The following year the Company's PCA filing was even greater. The issues were complex and required a careful balance between public policy concerns and the need to achieve just, fair and reasonable rates for recovering excess power costs. As it did in 2001, the Commission disallowed a portion of the jurisdictional power supply-related costs contained in the 2002 PCA filing.

Q. How did the Company view these PCA orders?

A. Although the Company was concerned to see disallowances emerge in the PCA, it generally viewed both the 2001 and 2002 Commission decisions as a signal that the Company was operating within the guidelines established by the IPUC and consistent with ratemaking concepts of the PCA. The decisions also lent valuable support to the Company during deteriorating financial circumstances.

Q. Please describe Idaho Power's most recent PCA filing.

A. During the 2002-2003 PCA period, wholesale energy prices had returned to pre-energy crisis levels. However, Idaho Power continued to be impacted by diminished precipitation levels and the resultant reduction in hydroelectric generation. On April 14, 2003, the Company filed a request to implement its annual PCA that would reduce overall rates by over 18 percent. On May 13, 2003, the Commission approved the Company's application. Despite the decrease, rate levels are still more than $80 million above Base Rate levels. With more normal snow pack and current prices, another PCA decrease could occur next spring.

Q. You previously discussed the impact of the Western energy crisis on the Company. Now, please elaborate on the Western energy crisis's impact on the Company's PCA.

A. When the PCA was first developed in 1992 and implemented in 1993, no one anticipated the types of market prices and volatility that occurred in 2000 and 2001.

At its inception, based on historical data, the anticipated power supply expense volatility was approximately $116 million from best to worst condition. During the western energy crisis, Idaho Power's power supply expenses were $204 million over those in Base Rates in 2001 and $337 million over base in 2002. The two years in combination were $541 million above base with the Company's shareholders absorbing over $127 million of that total amount. As a result, Idaho Power's customers and shareholders both bore substantial power supply costs that were of a magnitude not contemplated at the PCA's inception. The shareholders burden came from both the sharing mechanism and from disallowances in the 2001 and 2002 PCA orders.

Q. What is your impression of the PCA?

A. I believe that the PCA is a fair ratemaking mechanism that has recently been stress-tested under extreme conditions. Two of the attributes that have helped the mechanism stand the test of time are the true up and the sharing provision. The true up provides a means for actual costs to be ultimately accounted for and included. The sharing provision ensures that the interests of both the Company and its customers are aligned on each transaction.

Q. Since your Company has received significant cost recovery through the PCA in recent years, why do you need to file a general rate application?

A. The PCA only addresses the portion of the Company's total annual revenue requirement that corresponds to the variable cost of supplying energy to Idaho retail customers. The power supply expenses that flow through the PCA are normally limited to fuel for thermal plant operations and purchased power. The PCA mechanism also subtracts surplus sales revenues from these expenses. The sheer magnitude of the power supply expenses in recent years placed their ratemaking treatment at a higher regulatory priority than the pursuit of general rate relief. The Company not only had to prioritize its requests before the Commission, but recognize rate impacts to customers as well. Accordingly, the Company chose to postpone filing for general rate relief. Now in 2003, with the PCA component of our rates beginning to drop, other increasing expenses and new investments need to be brought before the Commission for inclusion in Base Rates.

Q. How has the Company's investment in electric plant grown since the last general rate case?

A. Since 1993, the test year for the last general rate case, the Company's investment in electric plant has grown by $856 million from nearly $2.32 billion to slightly over $3.17 billion. The $856 million represents a 10-year 37 percent increase in Company investment in electric plant on behalf of our customers. Put in annual terms, Company investment in electric plant has grown at about 3.2 percent per year since the last general rate case.

Q. Of the $856 million of additional investment in electric plant, please detail the growth in investment for generation, transmission, and distribution facilities.

A. In the last ten years, the Company has invested $156 million for generation additions and upgrades. The most recent generation plant addition was the Danskin gas-fired generation plant located in Mountain Home. The investment in the Danskin generation facility was approximately $50 million. In the same period of time the Company has invested $198 million toward the construction of transmission facilities and $366 million toward the construction of distribution facilities. The most recent investment in transmission facilities included in this application is the $19.4 million Brownlee-Oxbow 230 kV transmission upgrade. The remaining $136 million of investment growth is attributable to general and other plant items.

Q. Please describe the growth in Company expenses associated with operating and maintaining a $3.2 billion system.

A. The expenses associated with operating and maintaining a $3.2 billion system today have grown to about $540 million per year from the $412 million needed to operate and maintain a $2.3 billion system in 1994. The $128 million growth in expenses represents a 31 percent increase in expenses from levels established 10 years ago. Put in annual terms, Company expenses have grown at about 2.7 percent per year since 1993.

Q. Please describe the growth in Company revenues over the same 10-year period of time.

A. Since the last general rate case, Company test year operating revenues have grown only 13 percent compared to the 37 percent growth in investment and the 31 percent growth in expenses. Clearly, growth has not paid for itself. The incremental costs of adding, operating and maintaining generation, transmission and distribution plant are greater than the embedded costs associated with generation, transmission and distribution plant that have been the basis of Company rates over the last ten years.

Q. How has Idaho Power managed through this growth?

A. While both inflation and customer growth impact our expense level, the Company has actually been able to keep expenses well below the combined growth rate of inflation plus customer growth. I have had Exhibit No. 1 prepared to demonstrate these relationships over time. Exhibit No. 1 tracks the actual operating and maintenance (O&M) expenses from 1993 through 2002 and includes the 2003 O&M expenses that are part of the Company's general rate request. Exhibit No. 1 also tracks the 1993 O&M expenses over the same time period escalated by the combined impacts of inflation and customer growth.

Q. What is the current condition of Idaho Power's distribution system?

A. The system has been expanded to absorb the growth of the past decade. As noted before, over 40 percent of the Company's investment during this period has gone into the distribution system, yet many of the Company's distribution stations and lines are at or near capacity. During this time, we have worked diligently to improve operating efficiencies and utilization. However, there is little room to withstand additional growth without new construction.

Q. Please describe the operating capacity situation with the Company's distribution feeders.

A, The utilization of assets, or loading levels on feeders, has increased significantly. The peak load per distribution feeder in 1987 averaged 4.9 megawatts. Today, this has increased to 7.0 megawatts. Approximately one half of the retail load is served by feeders operating near their full capacity at peak load.

The Company has carefully prioritized and scheduled the construction of new facilities while relying heavily on our experienced workforce to manage and operate the system with these reduced margins.

Q. How is the Company managing new growth on its distribution system?

A. The Company has continued to manage substations and feeder loadings to meet growth through selective distribution capacity increases and the use of better load data acquisition systems. This has allowed the Company to utilize much of the reserve capacity once available. However, further reductions in reserve capacity would likely reduce reliability and service quality to our customers. Consequently, additional growth will require new facilities be added to the system at full marginal cost, rather than being able to leverage existing capacity in the system at the old embedded cost. The Company has identified over $400 million in growth-related sub-transmission, substation, and distribution infrastructure additions required prior to 2010. This does not include the ongoing costs of maintaining or replacing existing facilities.

Q. Since the last rate case, has Idaho Power Company invested in 230 kilovolt and above transmission facilities?

A. Yes. Contrary to reports of other utilities not investing in transmission infrastructure, Idaho Power has invested in backbone transmission facilities both to serve load and to improve service reliability. Since 1996, Idaho Power peak load has grown 526 megawatts. As a part of an over-all strategy to meet this load growth, the Company has undertaken several backbone transmission projects:

Brownlee-Ontario-Caldwell 230 kV Project	$30.5M
Boise Bench-Locust 230 kV	$ 5.7M
Brownlee 230 kV Bus Reconfiguration	$ 6.2M
Boise Bench 230 kV Bus Reconfiguration	$ 7.7M
Brownlee-Oxbow #2 230 kV Project	$19.4M
Goshen 345 kV Series Capacitor	$ 5.7M
Locust-Caldwell 230 kV Project	$19.3M

The Brownlee-Oxbow #2 Project and the Goshen Project will be completed in May 2004. The Locust-Caldwell Project is scheduled for completion in October 2004. On a dollar per kilowatts of capacity basis these projects cost about $180 per kilowatt.

Q. What are the drivers for this transmission investment?

A. Other than the Goshen project, which was done primarily for reliability purposes, the recent additions just mentioned were focused on maximizing the capacity of existing facilities. In other words, the Company has focused on making relatively small incremental improvements that increase the capacity of the system without having to resort to building significant long distance transmission lines. Fewer and fewer of these optimizing opportunities remain. Future transmission additions will likely be driven by the location of the load growth and where resource additions are developed.

Q. What are the transmission implications for the next ten years?

A. A significant portion of the Company's load growth is occurring in Ada and Canyon counties. The next ten years will require continuing transmission system facility improvements in this area.

Toward the end of this time horizon, the existing bulk transmission system serving the Treasure Valley area (Ontario to Mountain Home) will reach its maximum present capabilities and major transmission additions from the Northwest and/or areas east of Midpoint may become necessary.

Q. Based on recent experience, how will the cost of these new transmission facilities compare to previous transmission construction costs?

A. These future backbone expenditures will likely cost twice the previous expenditures for a comparable amount of load growth, about $400 per kilowatt or on average $20 million per year.

Q. What resource scenario was used in deriving these cost estimates?

A. As mentioned earlier, a key driver for transmission expansion is the location of future generating resources. The estimate of future backbone transmission expenditures assumes the Company will be able to construct or acquire local gas-fired combustion turbine additions in the next few years. Other resource strategies (wind, coal, etc.) may require significant transmission distances and would result in greater transmission expenditures.

Q. Will the recent east coast blackout have an impact on Idaho Power's transmission development?

A. The effects of the August 14, 2003 blackout on the east coast are not known at this time. One possible effect is a nationwide change in reliability standards; it could dramatically alter or advance transmission system expansion of the Idaho Power system and throughout the Western Interconnection.

Q. How has the Company's resource planning changed over the last ten years?

A. Prior to the Western energy crisis, we planned on median water conditions and assumed that energy would be available at reasonable prices in the wholesale market in below normal water years. Today our generation planning philosophy includes reducing market dependence and building resources as required under the 2002 Integrated Resource Plan (IRP). During the 2002 IRP process, public input supported this planning philosophy which is based upon more stringent criteria for both loads and resources.

Q. How does this new generation resource planning philosophy impact costs?

A. By using a less than median water planning criteria the need for additional resources will be accelerated. This applies to both peaking as well as base load facilities.

Q. Please describe the Company's current generating resources strategy.

A. Idaho Power will have to acquire a variety of resources throughout the coming years to meet its growing load requirement. The Company has recently notified Mountain View Power (MVP) that it is the successful bidder in the Company's most recent Request for Proposal for a generating resource. Once completed, MVP will transfer the plant to Idaho Power ownership. Idaho Power has decided to name this plant the Bennett Mountain Power Plant. The Bennett Mountain Power Plant will provide approximately 160 MW of peaking capacity. The Bennett Mountain Power Plant project will satisfy a portion of a portfolio of resources to be acquired to meet the 2002 IRP objectives. The Company has filed with the Idaho Commission for a Certificate of Convenience and Necessity for the Bennett Mountain Power Plant. In its application, Idaho Power has provided a commitment estimate of $54 million for the generation portion of the project, which is scheduled for completion in April 2005.

The results of the 2004 IRP will likely show additional resource needs in the near future.

Q. What is the current condition of the Company's jointly owned coal-fired resources?

A. As the demand for electricity has grown and the drought continues, we have relied heavily on our jointly owned coal-fired resources. These facilities were constructed in the 1970s through the early 1980s. As they age, they are in constant need of upgrading and rehabilitation. New environmental regulations have also added capital and maintenance requirements. We anticipate increased capital and O&M costs for these facilities in order to keep them reliable and compliant.

Q. What is the status of the Company's relicensing efforts?

A. Utilities throughout the country have licenses to operate hydropower projects to generate electricity. These licenses are granted by the Federal Energy Regulatory Commission (FERC). Licenses are usually granted for 30 to 50 years and define how hydropower projects may be operated for power generation as well as other measures that benefit the public. Idaho Power owns and operates 17 hydropower projects on the Snake River. By 2010, licenses will expire for eight Company projects affecting 12 different power-producing facilities. The Company has already applied, or is preparing to apply for a new license on each project. Exhibit No. 2 outlines the Relicensing Tasks Flow Chart for each project in their various stages of the FERC relicensing process. I would like to highlight the investment the Company has made in just one of these projects in particular, the Hells Canyon Complex.

On July 18, 2003, Idaho Power filed a formal application with the FERC to relicense the Company's three-dam Hells Canyon hydroelectric project. The Hells Canyon Complex is the largest of Idaho Power's 17 hydroelectric projects on the Snake River. Currently, over 420,000 customers rely on this complex for power as it produces nearly two-thirds of the hydroelectric generation and 40% of the total generation of the Company in an average water year. The final relicensing application consisted of 36,000-pages and was the culmination of nearly a decade of studies conducted by the company, focused on fish, wildlife, plants, water quality, recreation and cultural resources. Idaho Power conducted over 100 studies and ultimately the application process cost Idaho Power more than $50 million. The application also includes $324 million worth of new and continuing mitigation efforts to offset present and future environmental impacts resulting from the operation of the facility. These mitigation efforts, referred to as protection, mitigation, and enhancement (PM&E) measures include Water Use and Quality, Fish and Mollusc Resources, Wildlife Resources, Botanical Resources, Cultural Resources, Aesthetic Resources and Recreation Resources.

As the Relicensing Tasks Flow Chart shows, the Company began work on the Hells Canyon relicensing effort in early 1993. In September 2002 Idaho Power submitted a 25,000-page draft license application to the FERC and hundreds of stakeholders who constituted the Collaborative Team. The Company accepted over 4,500 written comments on its draft application through January 2003. Comments from the different respondents were addressed and included in the final new license application filed in July 2003. The FERC is planning to begin their National Environmental Protection Act process for the Hells Canyon project, with scoping meetings scheduled for the third week of November 2003 followed by requests for additional information in December 2003. The Company expects to incur consultation and compliance costs through 2008 followed by actual Article Compliance costs (once the FERC has issued a new license) that will continue well on in to the next decade. Exhibit No. 3 charts the Hells Canyon relicensing expenses incurred to date and the expected costs through 2010 at which time the Company will have spent approximately $100 million.

Q. What is the financial condition of Idaho Power Company?

A. The current financial situation has developed over a period of years. In 1999, the Company's short-term debt was $20 million, internal cash generation was at 114 percent, and we were experiencing sales growth in our service area.

In 2000, the combination of drought and energy crisis that I spoke of earlier built up a huge PCA deferral and caused us to file our annual PCA earlier than usual. As described previously, the IPUC ultimately approved most of the 2000-2001 PCA in two parts -- $168 million in May of 2001 and another $59 million in October of 2001. PCA disallowances of $11 million were written off in October of 2001. During 2000, capital expenditures increased to $132 million, while short-term debt rose to almost $60 million and internal cash generation fell to 42 percent.

By 2001 Idaho Power Company's regulated earnings per share had dropped to $.60 per share. 2001 was characterized by industry turmoil and continued Idaho drought. The "Perfect Storm" occurred with the combination of high market prices, lower-than-average stream flows, and higher demand. The PCA deferrals again grew, this time from the combined effects of the load reduction programs for the Astaris Special Contract and the irrigation customers. The un-recovered portion of the PCA costs absorbed by shareholders reached $76 million. Operating cash flow for Idaho Power was a negative $59.6 million. The short-term debt balance skyrocketed to $282 million. 2001 construction costs increased to $157 million, including $49 million for the Danskin Power Plant. Net working capital declined from 2000 to 2001 by $156 million. Utility operating income was also down from 2000 to 2001 by $79 million primarily due to the PCA absorption.

Idaho Power's earnings in 2002 were $2.24 per share, but these were heavily supported by a one-time $.92 income benefit related to a tax method change. Without it, the utility operation would not have earned enough to cover its dividend payment in 2002.

In 2003 the power supply costs finally began to drop leading to a rate decrease of 18 percent. However, customer growth and reliability requirements continue to drive the need for investment in transmission and distribution infrastructure.

Q. What are the implications of the current financial situation?

A. The Company needs to fund its operating and maintenance programs at adequate levels and needs to make additional investments in infrastructure to ensure continued high quality and reliable service for our customers. Looking forward, the capital expenditures are expected to remain high for the foreseeable future.

The cash flow situation has been precarious over the last several years. Utility earnings did not cover the dividend payment in 2001 and would not have covered the payment in 2002 except for the tax method change.

Q. Did Idaho Power's Board of Directors (the Board) recently vote to reduce the common stock dividend?

A. Yes. The Board voted on September 18, 2003 to reduce the total common stock dividend payment for the next quarter from $17,815,652 to $11,493,969, a reduction of $6,321,683. This resulted in a reduction in the IDACORP, Inc. annual dividend from $1.86 per share to $1.20 per share.

Q. Why did the Board take this action?

A. Idaho Power needs to strengthen its overall financial position so that it will be able to fund Idaho Power's $675 million, three-year capital expenditure program for the years 2004 through 2006. Reducing the dividend will improve cash flow and help maintain a strong credit rating while balancing the level of borrowing necessary to meet the growing capital requirements.

Q. How does the $675 million of estimated capital expenditures over the next three years compare with the capital expenditures for the most recent three years?

A. The Company's capital expenditures for the years 2001 through 2003 are expected to total $427 million. The forecasted growth of $675 million is a 58 percent increase. I had Exhibit No. 4 prepared to show the Company's actual/estimated capital expenditures for 2001 through 2006. Actual values have been included through July of 2003.

Q. How does the Board's decision relate to the Company's request for rate relief?

A. The Board recognized the need to generate more cash to invest in the utility infrastructure and strengthen the balance sheet. Accordingly, the Board decided to pay the owners less through the common stock dividend. In a similar fashion, timely rate relief also strongly supports increased cash flow and a stronger balance sheet with its corresponding enhanced credit worthiness.

Q. As president of Idaho Power, where is your focus?

A. My focus is the full restoration of Idaho Power as a preeminent fully integrated utility with the financial viability to successfully meet our customers' needs both now and in the future.

Q. What progress have you made?

A. In my view, we have made remarkable progress, particularly considering what we have been through in recent years. The Company has managed through the energy crisis and ongoing prolonged drought, taken steps to meet our customers' needs and reduce risks to them going forward, and made difficult decisions to maintain credit quality and financial flexibility. Running an efficient, quality utility is our priority and, as detailed in Ms. Fullen's testimony, customers are recognizing our efforts. I also believe that we have made some strides in the area of demand-side management (DSM). Ms. Fullen's testimony notes our senior management support in the DSM area. I affirm her testimony.

Q. What is your opinion of the Company's rate application?

A. Based upon the growth we have encountered over the last ten years, sound management through the energy crisis and ongoing drought conditions, and the system's needs going forward, I believe the Company's request for general rate relief is fair, just, and reasonable.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.