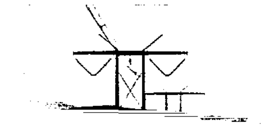
Central Vermont Public Service
2004 ANNUAL REPORT

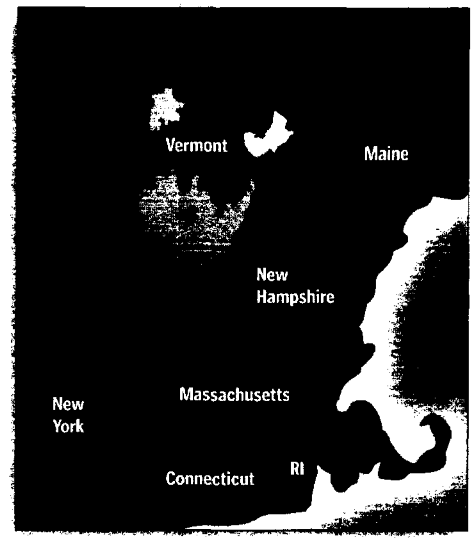
Energizing Vermont for
75 YEARS



Company Profile

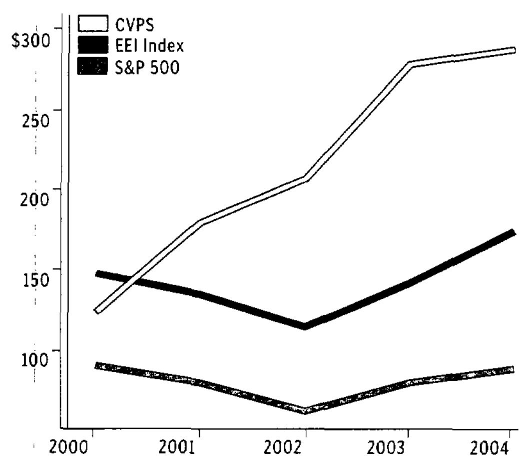
CVPS is Vermont's largest electric utility, serving over 149,000 customers. CVPS's service territory covers 4,450 square miles of Vermont's total land base of 9,609 square miles. CVPS Common Stock is listed on the New York Stock Exchange under the trading symbol CV.

CVPS has two non-regulated subsidiaries, Catamount Energy Corporation and Eversant. Catamount invests primarily in wind energy projects in the U.S. and U.K., while Eversant sells and rents electric water heaters through a subsidiary, SmartEnergy Water Heating Services. CVPS also maintains a 12 percent interest in The Home Service Store, a national home maintenance and repair business. More information about CVPS may be found at **www.cvps.com**.



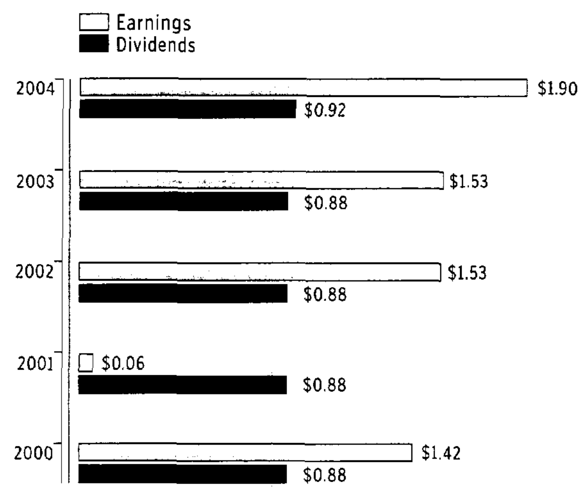
Central Vermont Public Service

Comparison of Five-Year Cumulative Total Return*

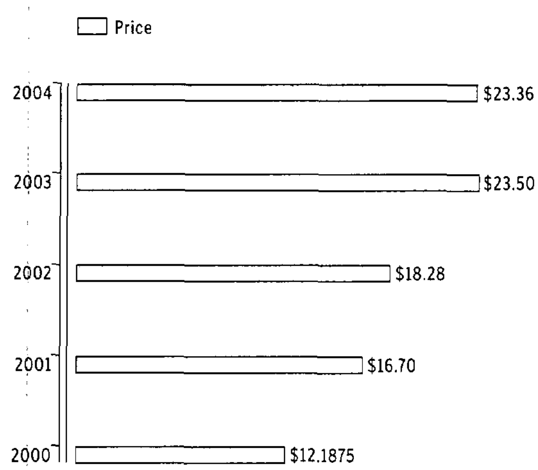


Assumes $100 Invested on December 31, 1999
*Total Return Assumes Quarterly Reinvestment of Capital Dividends

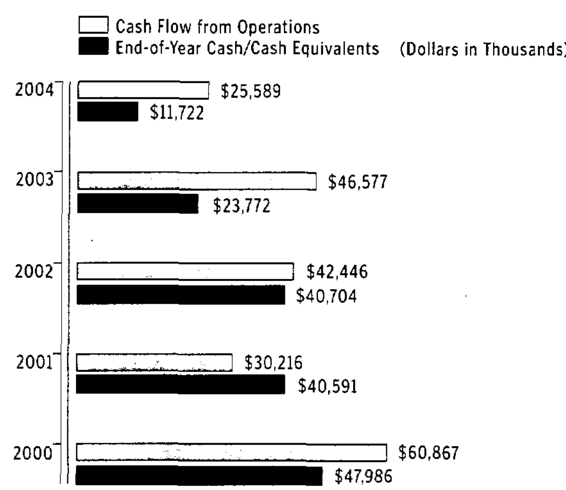
Earnings Per Diluted Share and Dividends



Year-End Stock Price



Cash Flow from Operations and End-of-Year Cash/Cash Equivalents



To Our Shareholders:

Central Vermont Public Service celebrated 75 years of energizing Vermont in 2004 by maintaining our tradition of financial stability, seamless service and disciplined growth. The success of our employees' work in these areas gives me great confidence for our future.

With total shareholder returns of 185.3 percent for the five years ending Dec. 31, 2004, CVPS ranked second in the Edison Electric Institute listing of small cap investor-owned utilities.

The company's 2004 performance was solid, thanks to continued focus on cost controls and work improvements, as well as one-time benefits such as the sale of Connecticut Valley Electric's assets. Net income was $23.8 million, or $1.90 per diluted share of common stock, compared to 2003 net income of $19.8 million, or $1.53 per diluted share of common stock.

CVPS's financial stability is matched by our corporate integrity. According to Institutional Shareholder Services, our corporate governance practices outperformed 92 percent of S&P 600 companies last year.

Virtually every facet of our service is improving, even as we continue to drive out costs. The company met or exceeded each of our 17 service standards, jointly developed with regulators, and customer satisfaction remains very high.

Roughly one-third of our workforce is expected to retire within five years, and maintaining seamless service requires a seamless transition of knowledge and skills. Succession planning is under way, and new employees are being hired so they can be trained and prepared for impending retirements. This will assure highly skilled employees will be able to maintain and continue to cost-effectively improve reliability and customer service.

Toward that end, CVPS and the International Brotherhood of Electrical Workers Local 300 signed a four-year contract, the longest in company history, effective at midnight Dec. 31, 2004. Interest-based negotiations focused on win-win outcomes, and produced the third straight contract approved on the union's first vote.

For many customers, improving service means having a renewable energy choice. To meet this need, the company developed and launched CVPS Cow Power™, a first-in-the-nation program linking customers, farm generation and the environment. More than 1,100 customers have already enrolled.

Our subsidiary Catamount Energy continues to build a stable and rapidly growing portfolio of wind projects. Construction of Sweetwater 2, the second phase of our first U.S. wind project, is complete, and Phase 3 is expected to be completed in 2005.

Looking ahead, we face challenges and opportunities. Vermont's transmission system must undergo significant improvements in the coming years. Vermont Electric Power Company, the state's transmission system operator, received approval early this year for a major project in northwest Vermont, but other work will also be needed to ensure system reliability. We plan to invest significant capital in these projects.

Ensuring fair and reasonable rates will also be critical. Last year, the Vermont Public Service Board opened an investigation of the company's 2004 rates and we asked for a rate increase, to be effective in April 2005, to ensure the company's ability to maintain reliable service and financial stability. We expect a decision in March.

As we reflect on our anniversary, it is clear that the company owes its success and longevity to the thousands of dedicated employees and patient, trusting investors who have worked at and invested in CVPS over the past 75 years. To paraphrase historian Stephen Ambrose, our past is a source of knowledge, and the future is a source of hope. We look forward to delivering on that hope in the years ahead.

Sincerely,

Robert H. Young

Robert H. Young
President and Chief Executive Officer

one might expect from a regulated electric utility. In 2004, we developed a new service offering directly linking our customers, farm generation and the environment.

Through CVPS Cow Power™, we've created a brand new market that gives customers a renewable energy choice, and provides Vermont farmers with new income and manure management opportunities. CVPS Cow Power™ is off to a great start. Since its approval by the Vermont Public Service Board in August, more than 1,100 customers have enrolled, supporting the development of renewable energy generated by burning methane from cow manure. Working with a wide variety of interest groups, we hope to build the farm and customer base to create and sustain a meaningful source of renewable energy in Vermont. This is an excellent example of how CVPS has sought out new ways to better serve customers, meet their needs, and reduce the environmental impacts of generating electricity. In this case, generation actually *benefits* the environment by helping solve significant air and water quality issues.

CVPS Cow Power™

The company's innovative CVPS Cow Power™ service gives customers a renewable energy choice, and provides Vermont farmers with new income and manure management opportunities to benefit the environment, and Vermont as a whole.
www.cvps.com/cowpower

DISCIPLINED, ENVIRONMENTALLY SOUND BUSINESS STRATEGY

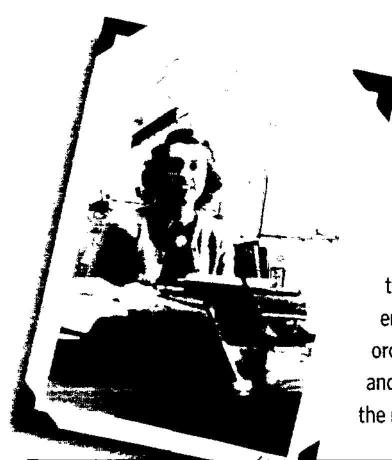
Sound stewardship of our investors' money and our natural resources directs our business strategy. In addition to core utility improvements, the company increases customer and shareholder value through timely investment in transmission projects critical to reliability. We also remain committed to development of clean energy from wind.

The transmission network is the backbone of the electric system – the lifeblood of virtually every business in America, even our way of life. We must continue to bolster and improve the system, while targeting efficiency programs to reduce the

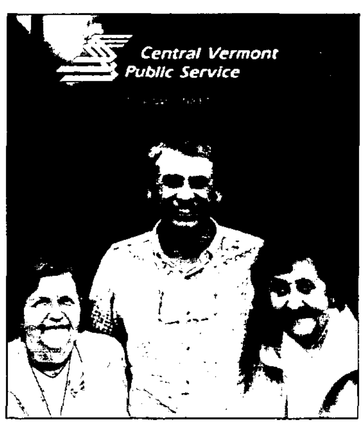
Shared History: Frankiewicz Family and CVPS

While much has changed at CVPS during the course of 75 years, one constant is the presence of at least one member of the Frankiewicz family. Joseph Frankiewicz—Old Joe to his fellow linemen—started with the company on Oct. 1, 1929, shortly after the corporation was organized. After more than 46 years with the company, he retired on Feb. 1, 1976—just a few weeks after Old Joe's nephew, C.J. Frankiewicz, started with CVPS. Joe's sisters, Sophie Frankiewicz Connors and Mary Frances Frankiewicz Riordan, also spent many years at the company, and C.J. is still here, so the family's service now spans a continuous 75 years. Today, C.J. Frankiewicz works as the company's Director of Revenue Requirements. "Joe was a lineman, and I am a bottom-line man," he says.

"Old Joe" Frankiewicz



Sophie Frankiewicz Connors (left) played the violin in the CVPS orchestra (below, under the banner), conducted by fellow employee Walter Belden. The orchestra played at various social and company functions throughout the region.



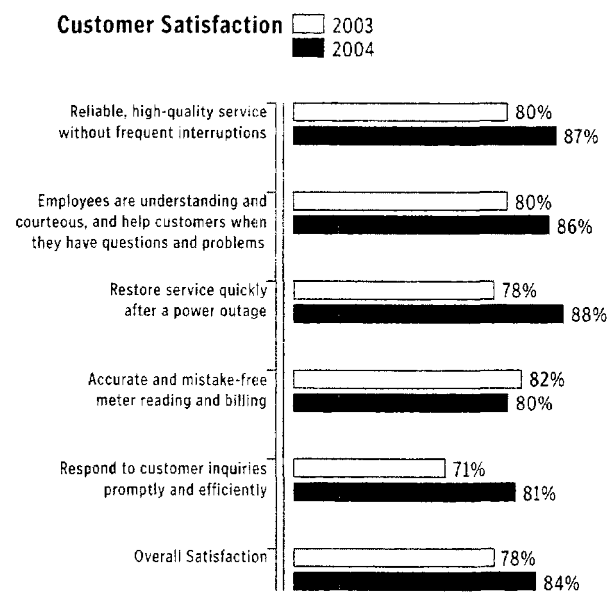
(Left to right) Mary Frances Frankiewicz Riordan, C.J. Frankiewicz and Sophie Frankiewicz Connors.

April 2004 determined our corporate governance practices outperformed 92 percent of S&P 600 companies. In strict compliance with the Sarbanes-Oxley Act, we completed a thorough review of all internal company controls for key business processes. No material weaknesses were identified by our auditors, resulting in the company receiving a clean opinion. Securing such a result is especially noteworthy given that more than 30 percent of all publicly traded companies are expected to report at least one material weakness in 2004. We remain committed to internal controls that assure timely, consistent and accurate financial reporting.

We are very pleased to have reached a new four-year contract in December with our unionized workers. Our new contract

Quality Service Satisfies Customers

CVPS met every one of the tough work-performance standards in our service quality and reliability plan called **SERVE**—Serving Everyone with **R**eliability **V**alue and **E**xcellence. Independent customer surveys also show high satisfaction.



with the International Brotherhood of Electrical Workers Local 300 was reached through interest-based negotiations focused on win-win outcomes. The union and management worked side by side to create an agreement that provides a fair benefit package to employees and helps control costs for our customers. This interest-based approach unleashes the power of collaboration to create a larger pool of value for all concerned.

These traits help to create an atmosphere of straight talk, with relationships based on mutual respect. Fully 94 percent of employees in a recent survey said they would recommend CVPS as a good place to work. This is critical to our success. Strong, open relationships bring positive results that directly affect our costs, service quality and financial performance.

ENSURING SEAMLESS SERVICE

For customers, increasing value can be seen in our service quality standards. Virtually every objective measure of our company's service is improving. From outages to phone answering, from meter reading to repairs, our employees excelled in 2004.

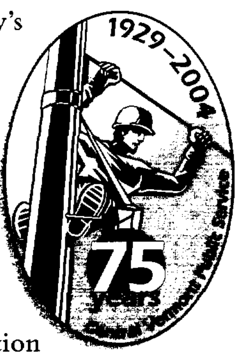
The company met or exceeded each of the 17 tough standards for work performance jointly developed with regulators. Surveys of our customer satisfaction have steadily increased. Given the high levels we've reached, continuing to improve won't be easy – but we will.

An estimated one-third of our workforce will retire over the next five years, but we're already preparing for that loss of experience. We have undertaken comprehensive succession planning to ensure a seamless transition of knowledge and skills.

Our solution is to "prehire" replacements for impending retirements of employees whose jobs demand a high level of training, such as line workers. This temporary but necessary step assures that highly skilled employees will be ready to fill the gaps when retirements occur. Succession planning has reduced our net vacancies related to retirements to nearly zero. This is imperative if we are to continually improve system reliability and customer service.

In addition to trained employees, seamless service demands sophisticated capital management. The company's new Asset Management Plan charts specific capital replacement and maintenance strategies for Transmission, Substation, Distribution, Meter and Generation asset areas, based on their specific operating performance. This comprehensive, long-term tool refines our ability to achieve the desired level of service and reliability while mitigating risk. Day-in, day-out reliability is very important, but our customer service goes beyond what

THIS IS OUR 75TH ANNUAL REPORT FOR CENTRAL VERMONT PUBLIC SERVICE CORPORATION.



From 1929 to 2004, this company's employees have energized Vermont. We work to grow investor value in harmony with our natural environment. We continue to improve, to demand more of ourselves, and to provide the best electric service possible at the lowest cost attainable.

2004 was emblematic of our tradition of energy-driven accomplishment. We earned successes that help assure our company's financial stability, protect and enhance our legacy of seamless service, and build opportunity for disciplined, environmentally sound, growth.

ENSURING FINANCIAL STABILITY

In 2004 we made great progress on ensuring our financial stability. Our $75 million second mortgage bond refinancing, completed in August, was greatly oversubscribed. The refinancing enabled us to secure a 300-basis-point interest rate decrease from the previous issue. This result exceeded our expectations, and will help reduce costs.

Such strong creditor interest in the company is well founded. In an Edison Electric Institute ranking of small capital utilities, those valued under $500 million, CVPS ranked second in the nation for total return. Shareholders earned a return of 185.3 percent for the five years ending Dec. 31, 2004.

Reducing power costs has been a key to maintaining this high level of performance. In November, we made two significant forward sales of excess energy, which are expected to stabilize net power costs over the next few years. These creative and well-executed transactions decreased net power cost volatility. Near the end of 2003 we sold forward excess energy available during the first quarter of 2004 and purchased replacement power to cover multiple planned outages in April to hedge against wholesale market-price volatility.

Vermont Yankee Nuclear Power Station's planned April plant reconfigurations and a subsequent unplanned 19-day shutdown this past summer led us to proceed cautiously and delay additional forward sales of excess power until the fourth quarter of 2004. One of the newly developed forward contracts provides for sale of excess energy only when VY is operating. These sales took advantage of stronger forward market conditions and provide for the resale of power made available from the settlement with the state of New Hampshire that resulted in the sale of the assets of our subsidiary, Connecticut Valley Electric Company (CVEC).

The CVEC sale, closed Jan. 1, 2004, ended years of litigation in New Hampshire with a positive outcome for our customers and investors. Thanks to a strong wholesale market and good power supply management, we have been able to offset other cost increases, while more than compensating for cancellation of the power supply contract between CVPS and CVEC.

The combined efforts of all of our employees enabled the company to avoid requesting a rate increase for nearly four years, despite inflation. To protect our ability to maintain reliable service and our financial stability, we asked the Vermont Public Service Board in July for a modest rate increase to be effective in April 2005. While we knew we would eventually need to ask for a rate increase, the timing of our request was in response to a 2004 rate investigation opened by the board. We expect a decision in March 2005.

Investor interest and confidence reflects our demonstrated commitment to honest and ethical conduct. Institutional Shareholder Services in

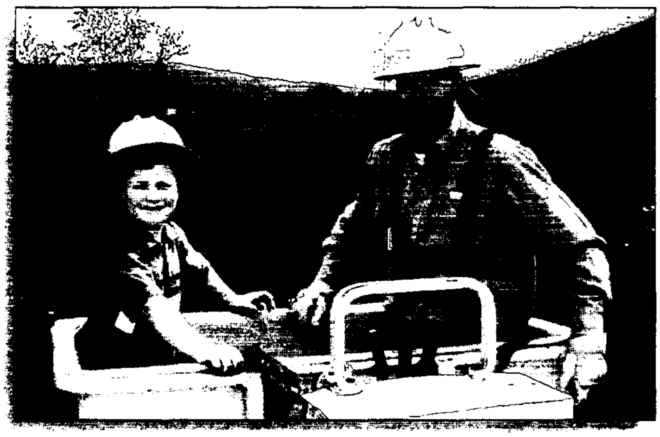
strain of heavy loads. In December 2004, we made an initial equity investment of $7 million in planned work of Vermont Electric Power Company, the state's transmission system operator. Additional VELCO investments totaling $30 million to $35 million are planned through 2007. This investment will help ensure long-term system reliability.

On a more global front, subsidiary Catamount Energy continues to focus on wind development in the United States and United Kingdom. Construction of Sweetwater 2, the second phase of our first U.S. wind project in Texas, was recently completed. Phase 3 is expected to be on line later this year. Catamount also entered a joint development agreement with Marubeni Power International to develop wind energy projects throughout New England, New York, and Pennsylvania.

Catamount continues to divest its non-wind assets, completing the sale of its Rupert and Glenns Ferry co-generation plants in Idaho in 2004, as well as the sale of its interest in the Thetford, England poultry litter plant. Catamount's U.S. portfolio stands at 234 megawatts in operation with net ownership of 84 megawatts, and over 400 megawatts in the development pipeline. The U.K. portfolio consists of over 300 megawatts under development, with the first project closing anticipated in 2006. These projects will meet power demands with clean, renewable energy and provide long-term, growing value for shareholders.

75th Anniversary Celebrations

What better way to celebrate our 75th Anniversary than to share it with the communities we serve? Employees volunteered their weekend time to mark this important milestone in the company's history with four Celebration & Safety Day events. With free admission and fare, the events featured exhibits and displays chronicling our past, energy efficiency information from Efficiency Vermont, and safety demonstrations by our line workers. Local and state fire, rescue and police agencies provided safety presentations and were able to recruit new volunteers. The celebrations gave us an opportunity to give back to them for all the help they've provided over the years.



Lineman Supervisor Louis Lacroix gives a lift to fellow lineman Mark Greenan's son, Patrick, at the St. Johnsbury 75th Anniversary and Safety Day Celebration.

KNOWLEDGE OF PAST, HOPE FOR THE FUTURE

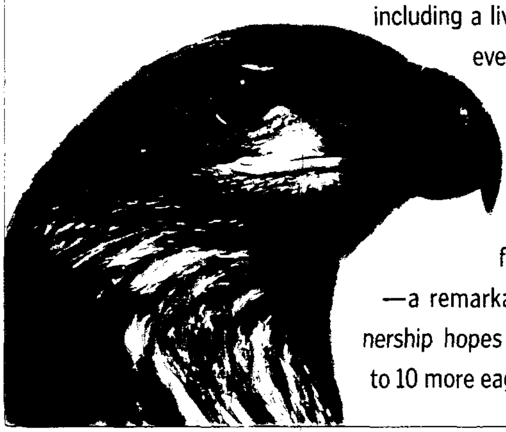
As noted historian Stephen Ambrose observed, "Our past is a source of knowledge, and the future is a source of hope. Love of the past implies faith in the future." Our company enjoys a storied past since its founding on Aug. 20, 1929, when eight local companies merged to become CVPS. CVPS began with fewer than 20,000 customers scattered across rural towns, valleys and mountains. Over the years, more than 100 companies merged into what is now the state's largest electric utility. Today, CVPS serves 149,000 customers, though still averaging just 19 customers per mile of line, spread across 12 of Vermont's 14 counties.

Albert Cree, whose roles as president, chairman and chief executive officer of the company spanned from the mid-'30s to the early '70s, earned national recognition for his leadership in extending service throughout Vermont. The company was a pioneer in the wind business, developing the nation's first utility-scale wind turbine to feed power onto an electric grid in 1941. CVPS was also a pioneer in utility communications. Decades before cell service and microwave phones, CVPS was the first electric utility in New England to install two-way radios in its service trucks in 1946, a decision believed to have saved countless lives when employees were able to warn officials of impending flooding in Rutland County in 1947. In 1975, the company was the first in the nation to install a ripple control load management system. The company and other partners in 1999 helped establish the first energy efficiency utility in the country. This pioneering spirit continues today with our CVPS Cow Power™ program.

As Central Vermont Public Service celebrates 75 years of service to Vermont, we face historic opportunities and challenges in the electric industry. We must secure clean and affordable energy to replace existing supplies that are due to expire in the next decade. We must continue to find new ways to ensure

Vermont Bald Eagle Restoration Initiative

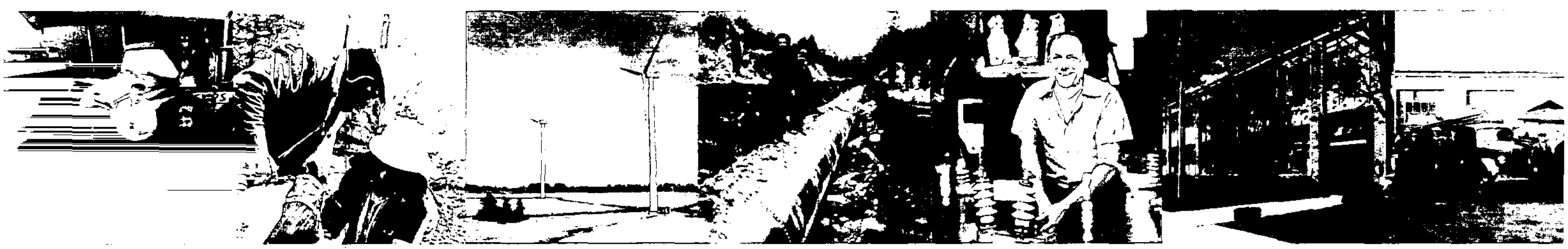
Following success in helping restore endangered ospreys to Vermont's skies, CVPS began to focus on bald eagles. The Vermont Bald Eagle Restoration Initiative was created in 2004 to help restore a breeding bald eagle population to Vermont, and CVPS is a full partner with the U.S. Fish and Wildlife Service, the Vermont Department of Fish and Wildlife, Outreach for Earth Stewardship, and the National Wildlife Federation. The company provided equipment, volunteer labor, materials for construction of eaglet boxes, and website development, including a live eagle cam. The company even hosts the project website at www.cvps.com/eagles. Volunteers' commitment to round-the-clock care was critical to successfully fledging eight chicks in 2004—a remarkable achievement. The partnership hopes to raise and release eight to 10 more eaglets in 2005 and 2006.



high-quality, reliable electric service. And we must regulate utility costs and rates in a manner that balances the interests of energy customers and investors. These three issues will largely define the industry—and the service we provide—in the years to come.

Our anniversary is an opportunity to acknowledge that the company owes its success to its employees and investors. This linkage was reaffirmed in 2004, as employees raised our service levels to new heights, and investors continued to show their confidence in the company and its people.

In 2005 and beyond, we will continue to raise our service standards. We will continue to give our employees the tools to succeed. And we will continue to provide a home for investors who value steady, environmentally sound, economic performance.



Award-winning Employee Wellness Program

Health and wellness is a financial concern to the company, to be sure, but we also know few issues emotionally affect each of us and our families so directly. CVPS is working hard with employees to improve our collective health. The goal of the company's Wellness Program is to improve employee health and productivity, and reduce the rate of growth in health care costs—a true win-win situation.

The company conducted a free health risk assessment for employees, identifying cardiovascular disease, weight/inactivity and stress as the most pressing health issues in our workforce. In response, we directed follow-up calls to the 75 most-at-risk employees based on their HRA results. Vending machines now contain more healthful snacks. We purchased and distributed health tools such as blood pressure monitors, body composition analyzers and hand sanitizers to help employees get and stay healthy. Most importantly, we provided our valuable employees with information, with encouraging results. Many dramatically changed their lives. Others have taken simple steps to improve their health—with big dividends.

Employee successes helped CVPS earn recognition as one of two Vermont companies to garner the "Gold Rising Star Award" from Governor Jim Douglas and the Vermont Governor's Council on Physical Fitness and Sports. The award lauds the company for "helping employees achieve better health" through the "most creative ways".

CVPS employees (from left) Gayle Ballou and Mary Eaton accept the "Gold Rising Star Award" from Vermont Governor Jim Douglas.

In this section we discuss the general financial condition and results of operations for Central Vermont Public Service Corporation (the "Company" or "we" or "our" or "us") and its subsidiaries. Certain factors that may impact future operations are also discussed. Our discussion and analysis is based on, and should be read in conjunction with, the accompanying Consolidated Financial Statements.

EXECUTIVE OVERVIEW

Our consolidated 2004 earnings were $23.8 million, or $1.90 per diluted share of common stock, compared to 2003 earnings of $19.8 million, or $1.53 per diluted share of common stock, and 2002 earnings of $19.8 million, or $1.53 per diluted share of common stock. In 2004, discontinued operations of Connecticut Valley Electric Company Inc. ("Connecticut Valley") contributed $12.3 million, or $1.00 per diluted share of common stock, to consolidated earnings. This reflects a $12.3 million after-tax gain related to the January 1, 2004 sale of Connecticut Valley's plant assets and franchise. In 2003, discontinued operations of Connecticut Valley contributed $1.4 million, or $.12 per diluted share of common stock, and it contributed $1.5 million, or $.13 per diluted share of common stock, in 2002. The primary drivers of consolidated earnings for the past three years are discussed in detail in Results of Operations below.

For accounting purposes, components of the Connecticut Valley transaction in 2004 are recorded in both continuing and discontinued operations in the consolidated statement of income. The gain on the asset sale, net of tax, totaled $12.3 million, but we recorded a loss on power costs, net of tax, of $8.4 million relating to termination of the power contract between us and Connecticut Valley. The loss is recorded as purchased power expense in the consolidated statement of income. When the two accounting transactions are combined to assess the total impact of the transaction, the result is a gain of $3.9 million, or $.31 per diluted share of common stock.

Key financial initiatives for the Company in 2004 included:

- Our request for a retail rate increase, discussed in Vermont Retail Rates;
- Refinancing Second Mortgage Bonds that matured on August 1, 2004, discussed in Liquidity and Capital Resources;
- Our continued investments in Vermont Electric Power Corporation, discussed in Liquidity and Capital Resources;
- Catamount's continued investments in wind energy projects and the sale of certain of its investments in non-wind energy projects, discussed in Diversification; and
- January 1, 2004 sale of substantially all of Connecticut Valley's plant assets and its franchise, discussed in Discontinued Operations.

FORWARD-LOOKING STATEMENTS

Statements contained in this report that are not historical fact are forward-looking statements intended to qualify for the safe-harbors from liability established by the Private Securities Litigation Reform Act of 1995. Whenever used in this report, the words "estimate," "expect," "believe," or similar expressions are intended to identify such forward-looking statements. Forward-looking statements involve estimates, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Actual results will depend upon, among other things:

- the actions of regulatory bodies, including the pending rate investigation and rate case before the Vermont Public Service Board;
- performance of the Vermont Yankee nuclear power plant;
- effects of and changes in weather and economic conditions;
- volatility in wholesale power markets;
- ability to maintain our current credit ratings;
- performance of our unregulated businesses; and
- other considerations such as the operations of ISO-New England, changes in the cost or availability of capital, authoritative accounting guidance and the effect of the volatility in the equity markets on pension benefit and other costs.

We cannot predict the outcome of any of these matters; accordingly, there can be no assurance that such indicated results will be realized. We undertake no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise.

COMPANY OVERVIEW

We are a Vermont-based electric utility that transmits, distributes and sells electricity and invests in renewable and independent power projects. We are regulated by the Vermont Public Service Board ("PSB"), the Connecticut Department of Public Utility and Control and the Federal Energy Regulatory Commission ("FERC"), with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. On January 1, 2004, our wholly owned regulated subsidiary, Connecticut Valley, sold its plant assets and franchise to Public Service Company of New Hampshire ("PSNH"). Prior to the sale, Connecticut Valley distributed and sold electricity in New Hampshire, and its activities were regulated by the New Hampshire Public Utilities Commission ("NHPUC"). Our wholly owned unregulated subsidiaries include: Catamount Energy Corporation ("Catamount"), which invests primarily in wind energy projects in the United States and United Kingdom; and Eversant Corporation ("Eversant"), which operates a rental water heater business through its subsidiary, SmartEnergy Water Heating Services, Inc.

The Vermont utility operation is our core business. As a regulated electric utility we have an exclusive right to serve customers in our service territory, which can generally be expected to result in relatively stable revenue streams. However, the ability to increase our customer base is limited to growth within the service territory, which has been relatively flat for several years. Given the nature of our customer base, weather and economic conditions are factors that can significantly affect our retail sales revenue. We currently have sufficient power resources to meet our forecasted load requirements, mostly through long-term power contracts. We sell any excess power we have in the wholesale markets administered by ISO-New England or to third parties in New England. Such sales help to mitigate overall power costs; but wholesale power market volatility can affect these mitigation efforts.

Our retail rates are set by the PSB after considering recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). While Vermont does not have a fuel or power adjustment clause, it is customary for the PSB to approve deferral of extraordinary costs incurred that might normally be expensed by unregulated businesses in order to match these expenses with future revenues.

Vermont regulatory issues remain our top priority. On July 15, 2004, we made two separate filings with the PSB: 1) a cost of service filing in the PSB's rate investigation; and 2) a request for a 5.01 percent rate increase. We also continue to monitor several State initiatives, one of which could, over time, shift utility regulation away from cost-based regulation.

In 2004, we refinanced our $75 million Second Mortgage Bonds, which matured on August 1, 2004, by issuing $75 million of First Mortgage Bonds. The lower interest rates resulting from the refinancing will reduce annual interest expense by about $2 million on a pre-tax basis. During 2004, we invested $7 million toward VELCO's planned transmission upgrade projects. Investments are made in Catamount on a project level basis upon review and approval of the Company's Management and Board of Directors.

The Vermont utility continues to generate sufficient cash flow to support ongoing operations. However, the outcome of the current rate case could negatively impact the utility's ongoing cash flow. While Catamount has sufficient cash flow to cover its operating expenses, additional project investments will require financing or additional funding by the Company. Catamount is also seeking investors and partners to co-invest in the development, ownership and acquisition of projects. See Liquidity and Capital Resources below for more detail regarding cash flow, investment opportunities and the bond refinancing.

VERMONT RETAIL RATES

Our current retail rates are based on a June 26, 2001 PSB Order approving a settlement with the DPS, which included a 3.95 percent rate increase effective July 1, 2001. As part of the settlement, we also agreed to a $9 million write-off ($5.3 million after-tax) of regulatory assets and a rate freeze through January 1, 2003. The order also ended uncertainty over Hydro-Quebec cost recovery by providing full cost recovery, made the January 1, 1999 temporary rates permanent, allowed the Vermont utility a return on common equity of 11 percent for the year ending June 30, 2002 (capped through January 1, 2004) and created new service quality standards. Lastly, the rate order requires us to return up to $16 million to ratepayers if there is a merger, acquisition or asset sale that requires PSB approval.

In April 2003, we filed cost of service studies for rate years 2003 and 2004, in accordance with the PSB's approval of the Vermont Yankee sale. The purpose was to determine whether a rate decrease was warranted in either year as a result of the sale of the Vermont Yankee plant. In July 2003, we agreed to a Memorandum of Understanding ("MOU") with the DPS regarding that filing. The MOU concluded that: 1) a rate decrease was not warranted; 2) we would decrease our allowed return on common equity from 11 percent to 10.5 percent effective July 1, 2003; 3) any earnings over the allowed cap of 10.5 percent would be applied to reduce deferred charges on the balance sheet; 4) we would file a fully allocated cost of service plan and a proposed rate redesign; and 5) we would work cooperatively with the DPS to develop and propose an alternative regulation plan.

Hearings on the MOU were conducted by the PSB in December 2003, and the PSB issued an Order on January 27, 2004 providing conditional approval for the MOU. It included the following significant modifications: 1) that the allowed return on common equity be reduced to 10.25 percent; 2) starting January 1, 2004 we would begin new amortizations of deferred charges on the balance sheet at December 31, 2003 of about $2.5 million annually; and 3) that we would file with the PSB a proposal to apply the $21 million payment we received in connection with the Connecticut Valley sale to write down deferred charges.

On February 3, 2004, we filed a Request for Reconsideration and Clarification, and in March 2004 participated in a workshop to review the filing. On April 7, 2004, the PSB denied our request. While the PSB agreed to remove the third modification, absent our acceptance of the remaining modifications, the PSB concluded that it would open a rate investigation. Consequently, the PSB issued an Order Opening Investigation and Notice of Prehearing Conference in Docket No. 6946 to investigate current rates.

On July 15, 2004, we filed a cost of service study in the rate investigation that demonstrated a rate deficiency of 2.4 percent, and recommended that rates should not be decreased retroactively to April 1, 2004. Also on July 15, 2004, we filed a request with the PSB for a 5.01 percent rate increase, expected to be effective April 1, 2005, and requested that the two cases be consolidated. On September 8, 2004, the PSB consolidated the two cases and confirmed a schedule for proceedings through 2004, with a final order in March 2005.

On October 1, 2004, the DPS filed its testimony with the PSB related to the rate investigation and our request for a rate increase. The DPS's major findings and recommendations included: 1) a rate refund to ratepayers retroactive to April 1, 2004 of 4.65 percent or $12 million; and 2) a rate reduction of 5.93 percent or almost $16 million on an annual basis effective with service rendered April 1, 2005. On October 1, 2004, AARP, an intervener in the case, filed testimony that supported a rate increase of up to 3.5 percent effective April 1, 2005. Technical hearings with the PSB began in early November 2004. Hearings and filings continued through February 2005.

In filings with the PSB on February 11 and 16, 2005, the DPS suggested: 1) a rate refund or credit to our ratepayers retroactive to April 1, 2004 of about 6 percent or $16 million; and 2) a rate reduction of about 7 percent or $19 million effective with service rendered April 1, 2005. While supporting the DPS position, AARP proposed the following modifications: 1) allow a 10 percent return on equity (the DPS recommended 8.75 percent); 2) amortize deferred debits over a six-year period (the DPS recommended a three-year period); and 3) exclude the costs associated with or resulting from the Connecticut Valley asset sale from our cost of service.

On February 18, 2005, the PSB approved our request for an Accounting Order that, among other things, allowed for deferral of certain 2004 utility earnings. The approved Accounting Order permitted us to record in other regulatory liabilities any earnings achieved by the utility in excess of the 11 percent return on equity. The earnings to be deferred were calculated by the same method we used for determining and reporting earnings for 2001, 2002 and 2003 under the mandated earnings cap of 11 percent per our July 2001 PSB-approved rate order. In 2004, utility earnings above the 11 percent return on equity amounted to $3.8 million pre-tax. We recorded this pre-tax amount as a regulatory liability, which will be accounted for as determined by the PSB in its final order. The issuance of the Accounting Order does not create any expectations, set any precedent, or in any other way impair the PSB's ability to rule on the contested issues in our rate case.

The DPS opposed our request for an Accounting Order and expressed concern that PSB approval of the Accounting Order would create the perception that regulators supported our proposed 11 percent return on equity and the method for calculating the earnings cap for the 2001 to 2003 period. The DPS suggested alternative methods to mitigate the financial impacts of a potential adverse decision. Those alternatives were not accepted by the PSB. However, the PSB's approval of the Accounting Order made clear that the 11 percent return on equity and the method for calculating overearnings for the period of 2001 to 2003 are in dispute in the rate proceedings and that the Accounting Order does not decide these issues.

The last PSB hearing was held on February 18 and the parties filed reply briefs on February 28, 2005. Our February 28, 2005 reply brief demonstrates that a reduction in rates for the period April 1, 2004 through March 31, 2005 would not be just or reasonable. Instead a modest increase (about 2.9 percent) in our rates beginning April 1, 2005 is justified. We based our conclusion on the terms of the power cost settlement reached with the DPS and application of the $3.8 million deferred 2004 earnings to reduce deferred charges eligible for recovery in rates. Both of these items require approval by the PSB. A final decision from the PSB is expected on March 25, 2005. We cannot predict the outcome of the rate case at this time.

ENERGY INITIATIVES IN VERMONT

The State of Vermont continues to examine changes to the provision of electric service absent introduction of retail choice. The following discussion highlights initiatives of potential significance.

Renewable Portfolio Standard In 2003 and 2004 several bills were introduced in the Vermont General Assembly to establish a Renewable Portfolio Standard ("RPS") requirement. The introduction of an RPS could require that we purchase certain amounts of our energy supply requirement from new renewable sources while maintaining existing renewable power content. Although none of those bills were enacted into law, there remains an interest in RPS, and several proposals have been introduced in the 2005 legislative session. These proposals are similar to a proposal in the PSB's 2004 report to the Vermont General Assembly. Based on activity in the current legislative session, we expect that a mandatory RPS, in some form, will be approved.

Renewable Pricing Programs Beginning in 2003, the Vermont General Assembly authorized the establishment of utility-sponsored renewable pricing programs to permit customers to voluntarily elect to purchase all or part of their electric energy from renewable sources, or cause the purchase and retirement of tradable renewable energy credits on the participating customers' behalf. In either case, the purpose of such pricing programs is to increase the utility's reliance on renewable sources of energy beyond those the utility would otherwise be required to provide under its PSB-approved Integrated Resource Plan. Our first renewable pricing program, "CVPS Cow Power™," was approved by the PSB on July 30, 2004. The program promotes the production of renewable energy from cow manure from certain Vermont farms, and was made available to customers for energy use starting September 1, 2004. Pricing for the program is in the form of a premium relative to the tariff that would otherwise apply. The premium is cost-based so that it reasonably reflects the difference between acquiring the renewable energy and our alternative cost of power. The program also requires that any costs of power in excess of our alternative cost of power be borne by those customers participating in the program. By year end, about 900 customers had signed up for CVPS Cow Power™.

Alternative Forms of Regulation In 2003, the Vermont General Assembly authorized alternative forms of regulation for electric utilities that, besides other criteria, establish a reasonably balanced system of risks and rewards to encourage utilities to operate as efficiently as possible. The PSB may only approve an alternative regulation plan if it finds that the plan will not adversely affect our eligibility for rate-regulated accounting in accordance with accounting principles generally accepted in the United States of America ("GAAP") and reasonably preserves the availability of equity and debt capital resources to us on favorable terms and conditions. At this time, we have not sought authorization to implement an alternate form of regulation.

BUSINESS RISKS

Regulatory Risk On July 15, 2004, we made two separate filings with the PSB: 1) a cost of service in the PSB's rate investigation; and 2) a request for a 5.01 percent rate increase. These matters are discussed in more detail above.

Historically, electric utility rates in Vermont have been based on a utility's costs of service. As a result, electric utilities are subject to certain accounting standards that apply only to regulated businesses. Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71") allows regulated entities, such as the Company, in appropriate circumstances, to establish regulatory assets and liabilities, and thereby defer the income statement impact of certain costs and revenues that are expected to be realized in future rates. The Company currently complies with the provisions of SFAS No. 71 for its regulated Vermont service territory and FERC-regulated wholesale businesses. If we determine the Company no longer meets the criteria under SFAS No. 71, the accounting impact would be an extraordinary charge to operations of about $38.9 million on a pre-tax basis as of December 31, 2004, assuming no stranded cost recovery would be allowed through a rate mechanism.

Although not currently under consideration, if retail competition were implemented in our Vermont service territory, we are unable to predict the impact on our revenues, our ability to retain existing customers with respect to their power supply purchases and attract new customers or the margins that will be realized on retail sales of electricity, if any such sales are sought.

Wholesale Power Market Risk Our material power supply contracts and arrangements are principally with Hydro-Quebec and Vermont Yankee Nuclear Power Corporation ("VYNPC"). These contracts support the majority of our total annual energy (mWh) purchases. Our exposure to market price volatility is limited for power supply purchases given that our long-term power forecast reflects energy amounts in excess of that required to meet load requirements. However, if one or both of these sources becomes unavailable for an extended period of time, we would be subject to wholesale power price volatility and that amount could be material. Additionally, we rely on the sale of our excess power to help mitigate overall net power costs and price risk. The volatility of wholesale power market prices can impact these mitigation efforts.

We also continue to monitor, and adapt to, changes to New England wholesale power markets and open access transmission systems. These are discussed in more detail in Power Supply Matters below.

Inflation The annual rate of inflation, as measured by the Consumer Price Index, was 2.7 percent for 2004, 2.3 percent for 2003 and 1.6 percent for 2002. Our revenues are based on rate regulation that generally recognizes only historical costs; therefore, inflation continues to have an impact on most aspects of the business.

Unregulated Business Catamount is wholly focused on the development, ownership and asset management of wind energy projects. Catamount's future success is dependent on continued acceptance of wind power as an energy source by large producers, utilities and other purchasers of electricity. In addition, many potential customers believe that wind energy is an unpredictable and inconsistent resource, is uneconomic compared to other sources of power and does not produce stable voltage and frequency. There is no guarantee of wind power acceptance by potential customers as an energy source. The following highlights the wind-related risks that we believe are most critical to Catamount.

- *Wind Resource and Weather Pattern Risks* – Generation of electricity by wind energy projects is highly dependent upon wind conditions at the site. Although wind energy projects are developed with careful review of available historic wind and weather patterns at a particular site, there is no assurance that Catamount can accurately forecast future long-term wind resources at any one site. In addition, average wind speeds and resources can vary widely in any year, resulting in significant annual revenue variability.
- *Power Purchase Agreement Risk* – Catamount will only invest in wind power projects that have power purchase agreements in place with acceptable third parties. The creditworthiness of such acceptable third parties varies and can result in risk to Catamount. Additionally, competitive bidding generally has reduced the price utilities pay independent power producers, which, in turn, reduces the profitability of many independent power projects.
- *Wind Turbine Generator Technology Risk* – Wind turbine generators ("WTGs") of the size Catamount intends to utilize have only been commercially available for three or four years. Long-term reliability of this equipment has yet to be proven. Wind turbine technology is rapidly changing with WTGs' growth in size and rated output every year. Problems with key components in newer turbine models without long track records could result in unexpected availability losses, increased and unbudgeted maintenance and repair costs, and lack of electric production affecting revenue generations. Wind energy projects typically consist of many WTGs of one particular make and model. Therefore, any failure of a key component could result in serial failures of such component throughout the wind energy project, resulting in significantly diminished revenues and materially increased maintenance and repair costs.
- *Dependence on Governmental Policies* – The wind energy industry is

highly dependent upon governmental policies and laws enacted to stimulate growth of clean renewable energy through tax credits and other incentive plans, including mandatory purchasing requirements by local utilities of renewable energy, including wind energy. While the trend worldwide is to increase the use of renewable energy sources, there is no assurance that any particular governmental policy or tax credit or incentive program will be continued in any jurisdiction where Catamount conducts business.

- *Credit Risk* – Recent events, including uncertainties concerning operations of wholesale markets and the demise of major wholesale power marketing companies, have increased credit concerns in the energy industry specifically with unregulated energy companies. Obtaining or renewing corporate credit facilities is challenging and there is no guarantee credit will either be extended or renewed. Catamount terminated its credit facility in May 2004. Catamount solicits, as needed, proposals from selected financial institutions for corporate and/or development credit facilities that will meet its business needs. Catamount cannot predict whether it will be able to ultimately solicit and enter into an appropriately priced corporate and/or development credit facility.
- *Capital Requirements* – Catamount will require additional capital to pursue its business plan. Catamount is seeking investors and partners to co-invest in the development, ownership and acquisition of projects. There can be no assurance that Catamount will be successful in securing a partner or obtaining additional funding from us.

Also see Quantitative and Qualitative Disclosures About Market Risk for additional information related to market risk associated with our regulated utility business.

DISCONTINUED OPERATIONS

On January 1, 2004, Connecticut Valley completed the sale of substantially all of its plant assets and its franchise to PSNH. The sale, including termination of the power contract between us and Connecticut Valley, resolved all Connecticut Valley restructuring litigation in New Hampshire and our stranded cost litigation at FERC.

Cash proceeds from the sale amounted to about $30 million, with $9 million representing the net book value of Connecticut Valley's plant assets plus certain other adjustments, and $21 million as described below. In return, PSNH acquired Connecticut Valley's franchise, poles, wires, substations and other facilities, and several independent power obligations.

As a condition of the sale, Connecticut Valley paid us $21 million to terminate its long-term power contract. In accordance with SFAS No. 5, *Accounting for Contingencies* ("SFAS No. 5"), in the first quarter of 2004, we recorded a $14.4 million pre-tax loss accrual related to termination of the power contract. The loss accrual represented Management's best estimate of the difference between expected future sales revenue, in the wholesale market, for the purchased power that was formerly sold to Connecticut Valley and the cost of purchased power obligations. See discussion of Reserve for Loss on Power Contract in Critical Accounting Policies below.

For accounting purposes, components of the sale transaction are recorded in both continuing and discontinued operations in the Consolidated Income Statement. In 2004, income from discontinued operations included a gain on disposal of discontinued operations of about $21 million, pre-tax, or $12.3 million, after-tax, reflecting the $30 million payment from PSNH, net of various other adjustments. In addition to the gain on disposal, we recorded a loss on power costs, net of tax, of $8.4 million relating to termination of the power contract with Connecticut Valley as described above. The loss is included in Purchased Power on the Consolidated Statement of Income. When the two accounting transactions are combined to assess the total impact of the sale, the result is a gain of $3.9 million recorded in 2004.

On January 1, 2004, Connecticut Valley also paid in full a $3.8 million inter-company promissory note that was payable to us. There are no remaining significant business activities related to Connecticut Valley. Summarized results of operations of the discontinued operations are as follows (in thousands):

	For the years ended December 31 2004	2003	2002
Operating revenues	$23	$19,728	$20,242
Operating expenses			
Purchased power	-	14,725	15,283
Other operating expenses	43	2,049	1,989
Income tax (benefit) expense	(7)	1,232	1,224
Total operating expenses	36	18,006	18,496
Operating (loss) income	(13)	1,722	1,746
Other expense, net	(1)	(276)	(203)
Net (loss) income, net of tax	(14)	1,446	1,543
Gain from disposal, net of $8,706 tax	12,354	-	-
Income from discontinued operations, net of tax	**$12,340**	$1,446	$1,543

Purchased Power in the table above includes about $10.4 million in 2003 and $10.9 million in 2002 related to the purchase of power from the Company, under Connecticut Valley's long-term contract with the Company. These amounts are included in Operating Revenue on the Consolidated Statements of Income. Accounts Receivable from Connecticut Valley were of a nominal amount in 2004 and $1.8 million in 2003.

The major classes of assets and liabilities reported as discontinued operations on the Consolidated Balance Sheets are as follows (in thousands):

	2004	2003
Assets		
Net utility plant	$-	$9,251
Other current assets	-	41
Total assets of discontinued operations	$-	$9,292
Liabilities		
Accounts payable	$-	$1,749
Short-term debt (a)	-	3,750
Total liabilities of discontinued operations	$-	$5,499

(a) Related to an inter-company Note that was paid on January 1, 2004.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2004, we had cash and cash equivalents of $11.7 million and working capital of $67.7 million. During 2004, cash and cash equivalents decreased by $12.1 million. The decrease resulted from the following: 1) $52.1 million used by investing activities mostly for Catamount investments, construction expenditures, investment in VELCO and investments in available-for-sale securities as described below, partly offset by sales of projects from Catamount's portfolio; 2) $15.7 million used in financing activities primarily related to dividends paid on common and preferred stock and retirement of long-term debt and preferred stock; 3) $25.6 million provided by operating activities; and 4) $30.1 million provided by discontinued operations.

At December 31, 2003, we had cash and cash equivalents of $23.8 million and working capital of $68.6 million. During 2003, cash and cash equivalents decreased $16.9 million. The decrease resulted from the following: 1) $35.1 million used by investing activities for available-for-sale securities, construction expenditures, partially offset by the Vermont Yankee sale proceeds received in

2003; 2) $27.3 million used in financing activities mostly related to retirement of long-term debt and dividends paid on common and preferred stock and $10.6 million for restricted cash used to reduce non-utility long-term debt and redeemable preferred stock; and 3) $46.6 million provided by operating activities.

In the first quarter of 2004, we invested proceeds received from the Connecticut Valley sale and other cash on hand in available-for-sale securities with various maturities. At December 31, 2004, these investments included $19.3 million with maturities from 90 days up to one year and $21.9 million with maturities greater than one year.

We are considering investment alternatives and plan to continue investing additional funds in Vermont Electric Power Corporation, Inc.'s ("VELCO") planned transmission upgrades. Our investments in VELCO will contribute toward increasing VELCO's common equity from about 10 percent to 25 percent of its total capitalization. On August 17, 2004, FERC approved our joint filing with Green Mountain Power Corporation ("GMP") for authorization to purchase stock to be issued by VELCO in 2004 and 2005 in connection with financing its planned transmission upgrades. We invested about $7 million in December 2004 and intend to invest about $5.7 million in the latter part of 2005. VELCO will require additional equity capital beyond 2005 in order to finance all of the proposed transmission upgrades and we will consider additional investments in VELCO. In total, our investments in VELCO, including our December 2004 investment, could amount to about $30 million to $35 million through 2007.

Catamount has sufficient cash flow to cover its ongoing operating expenses, but additional project investments will require financing or additional funding from us. Catamount is also seeking investors and partners to co-invest in the development, ownership and acquisition of projects.

We believe that cash on hand and cash flow from operations will be sufficient to fund our business for the foreseeable future, although without a rate increase, Vermont utility cash flow from operations will decrease in 2005 when compared to 2004. Material risks to cash flow from operations include: adverse rate case outcome; loss of retail sales revenue from unusual weather; slower-than-anticipated load growth and unfavorable economic conditions; and increases in net power costs largely due to lower-than-anticipated margins on sales revenue from excess power.

Capital Commitments and Contractual Obligations

The Vermont utility is a capital-intensive operation, as it requires annual construction expenditures to maintain the distribution system. Our capital expenditure plan is expected to range from $60 million to $70 million for the three-year period between 2005 and 2007. Our significant contractual obligations as of December 31, 2004 are summarized in the table below.

CONTRACTUAL OBLIGATIONS	Total	Payments Due by Period (in millions) Less than 1 year	1 - 3 years	3 - 5 years	After 5 years
Long-term debt – utility	**$126.8**	-	-	$8.5	$118.3
Interest on long-term debt – utility (a)	**114.6**	$7.3	$14.6	14.4	78.3
Redeemable preferred stock	**8.0**	1.0	2.0	2.0	3.0
Purchased power contracts (b)	**1,295.9**	134.3	280.8	289.7	591.1
Nuclear decommissioning and other closure costs (c)	**22.6**	5.4	8.0	6.3	2.9
Capital leases	**11.8**	1.7	2.8	2.2	5.1
Operating vehicle lease (a)	**4.9**	1.1	1.9	1.3	.6
Total Contractual Obligations	**$1,584.6**	$150.8	$310.1	$324.4	$799.3

(a) Based on interest rates as of December 31, 2004.
(b) Includes power contract commitments with Hydro-Quebec, VYNPC and various independent power producers. See Power Supply Matters below for more information related to these contracts.
(c) Includes estimated decommissioning and all other closure costs related to Maine Yankee, Connecticut Yankee and Yankee Atomic. See Power Supply Matters below for more information regarding these plants.

Pension and Postretirement Benefits

See Note 10 to the Consolidated Financial Statements for expected cash flows related to Pension and Postretirement Benefits.

Financing

Utility On July 30, 2004, we issued $20 million of 5 percent First Mortgage Bonds, due in 2011, and $55 million of 5.72 percent First Mortgage Bonds, due in 2019. The proceeds were used to repay in full our $75 million Second Mortgage Bonds, at a rate of 8.125 percent, that matured on August 1, 2004. The refinancing and lower interest rates will reduce annual interest expense by about $2 million on a pre-tax basis.

The First Mortgage Bonds are callable at our option at any time upon payment of a make-whole premium, calculated as the excess of the present value of the remaining scheduled payments to bondholders, discounted at a rate that is 0.5 percent higher than the comparable U.S. Treasury Bond yield, over the early redemption amount.

Currently, the Vermont Industrial Development Authority Bonds and the Connecticut Development Authority Bonds are callable at par at the option of the Company or bondholders on each monthly interest payment date, or at the option of the bondholders on any business day. We have always been able to remarket any bonds submitted for prepayment by the bondholders. The New Hampshire Industrial Development Authority Bonds are no longer callable at our option or at the bondholders' option, except in special circumstances involving unenforceability of the indenture or a change in the usability of the project.

None of our debt financing documents contain cross-default provisions to affiliates outside of the consolidated entity. Certain of our debt financing documents contain cross default provisions to our wholly owned subsidiaries, East Barnet, CV Realty and Custom Investment Corporation. These cross-default provisions generally relate to an inability to pay debts or debt acceleration, inappropriate affiliate transactions or the levy of significant judgments or attachments against our property. Currently, we are not in default under any of our debt financing documents.

Based on outstanding debt at December 31, 2004, no principal payments are due on long-term debt from 2005 through 2007. At December 31, 2004, substantially all utility property and plant were subject to liens under the First Mortgage Bond indenture. Also, the First Mortgage Bond indenture restricts financial support to Catamount and other unregulated subsidiaries at $17.5 million plus 20 percent of annual net income starting January 2004 and prevents any guarantee of Catamount's or other unregulated subsidiaries' obligations. In return, the First Mortgage Bond indenture eliminates the risk of cross default by Catamount and other unregulated subsidiaries. At December 31, 2004, we were in compliance with all debt covenants related to our various debt agreements, Articles of Association and letters of credit; these agreements contain financial and non-financial covenants.

Dividend restrictions: The First Mortgage Bond indenture and the Company's Articles of Association contain certain restrictions on the payment of cash dividends on capital stock. Under the most restrictive of such provisions, approximately $99 million of retained earnings was not subject to dividend restriction at December 31, 2004.

Non-Utility In January 2004, Catamount paid off a $2.5 million balance on its term loan, and in February 2004, Catamount notified the lender of its intent to terminate the credit facility. Effective May 16, 2004, the credit facility was officially terminated. Catamount's office building mortgage matured on April 15, 2004, and Catamount paid the outstanding balance in full.

Catamount solicits, as needed, proposals from selected financial institutions for corporate and/or development credit facilities that will meet its business needs. Catamount cannot predict whether it will be able to ultimately enter into an appropriately priced corporate and/or development credit facility.

As part of its windfarm development efforts, in August 2004, Catamount entered into a construction lending arrangement for about $27.3 million for a wind project located in the United States. At December 31, 2004, Catamount advanced $22.6 million for construction of the project. On February 11, 2005, the construction loan was paid off and Catamount made an equity investment in the wind project referred to as Sweetwater 2.

In November 2004, Catamount entered into an agreement with a third-party developer for the purchase of wind turbines for a joint development project. Pursuant to the agreement, Catamount made a total of $5.9 million of payments to the turbine supplier in the fourth quarter of 2004. The turbine supply agreement calls for payments of $5.9 million in March 2005 and $14.8 million in September 2005, with the remaining contract amount of $32.5 million due based on milestones established in the agreement. Catamount expects third-party construction financing for the wind project that the turbine agreement is associated with to be in place in the second quarter of 2005. Once the construction financing is in place, Catamount would be relieved of making the September 2005 and remaining payments to the turbine supplier. The turbine supply agreement allows for termination in full up to 30 days prior to the delivery of the first turbines. After that date, Catamount can terminate future turbines (partial termination) 30 days prior to scheduled delivery. In the event of a termination of the turbine supply agreement in whole or in part for the joint development project, the third-party developer or Catamount has up to 18 months from the termination date to utilize the turbines and receive reimbursement of 85 percent of the turbine down-payments.

Off-balance sheet arrangements

Letters of Credit: We renewed $16.9 million of unsecured letters of credit issued by a financial institution to November 30, 2005. These letters of credit support three series of Industrial Development Revenue Bonds, totaling $16.3 million. At December 31, 2004 and 2003, there were no amounts outstanding under these letters of credit.

Operating Leases: We lease our vehicles and related equipment under one operating lease agreement. The leases are mutually cancelable one year from each individual lease inception. We have the ability to lease vehicles and related equipment up to an aggregate unamortized balance of $10 million, of which about $4.4 million was outstanding for the years ended 2004 and 2003.

Under the terms of the vehicle operating lease, we have guaranteed a residual value to the lessor in the event the leased items are sold. The guarantee provides for reimbursement of up to 87 percent of the unamortized value of the lease portfolio. Under the guarantee, if the entire lease portfolio had a fair value of zero at December 31, 2004, we would have been responsible for a maximum reimbursement of $3.9 million and at December 31, 2003, we would have been responsible for a maximum reimbursement of $3.8 million. We had a liability of $0.1 million at December 31, 2004 representing our obligation under the guarantee based on the fair market value of the entire portfolio.

Other operating lease commitments are considered minimal, as most are cancelable after one year from inception. Total rental expense, including the operating lease agreement described above, included in the determination of net income, amounted to about $5.2 million in 2004, $4.4 million in 2003 and $4.5 million in 2002.

Power Supply Commitments: We have material power supply commitments that are discussed in detail in Note 13 – Commitments and Contingencies.

Equity Investments: We own an equity interest in VELCO in which we are required to pay a portion of VELCO's operating costs based on our network load percentage and to contribute additional capital if VELCO's transmission rates do not provide for full cost recovery. We own an equity interest in VYNPC in which we are obligated to pay a portion of VYNPC's operating costs based on our entitlement percentage. See Note 2 – Investments in Affiliates for additional information related to these equity investments.

Other: We do not use off-balance sheet financing arrangements, such as securitization of receivables, or obtain access to assets through special purpose entities.

Credit Ratings

On November 16, 2004, Standard & Poor's ("S&P") affirmed our corporate credit rating at 'BBB-', and reported the rating outlook as stable. S&P indicated that the affirmation was based upon an average business profile and a somewhat below-average financial profile. Our financial profile is pressured by adjustments made by S&P related to some of our long-term purchased power contracts. Our business profile is characterized by a diverse customer mix, stable demand growth and low operating risk. These strengths are offset by significant regulatory uncertainty and our continued commitment to non-regulated businesses, including wind-power projects in the United States and United Kingdom. S&P's stable outlook was based upon expectations that our regulatory environment will not deteriorate and that future financial support of unregulated businesses will be measured.

On December 14, 2004, Fitch Ratings ("Fitch") upgraded our preferred stock rating to 'BBB-' from 'BB+'. Fitch also affirmed our first mortgage bond rating at 'BBB+' and reported the rating outlook as stable. Fitch indicated that the higher ratings reflect the Company's strengthening credit measures and lower business risk related to the 2001 rate order, which provided full recovery of Hydro-Quebec purchased power agreement costs. Another factor was the sale of Vermont Yankee, eliminating the Company's nuclear operating risk.

Our credit is currently investment grade. Credit ratings should not be considered a recommendation to purchase stock. Current credit ratings are as follows:

	Standard & Poor's (1)	Fitch (1)
Corporate Credit Rating	BBB-	N/A
First Mortgage Bonds	BBB+	BBB+
Preferred Stock	BB	BBB-

(1) Outlook: Stable

Capitalization Our capitalization for the past two years is as follows:

	Amount (in millions)		Percent	
	2004	2003	2004	2003
Common stock equity	$225	$211	60%	57%
Preferred stock *	16	18	4	5
Long-term debt *	127	129	34	35
Capital lease obligations*	8	9	2	3
	$376	$367	100%	100%

* includes current portion

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our financial statements are prepared in accordance with GAAP, requiring us to make estimates and judgments that affect reported amounts of assets and liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements. Our most critical accounting policies are described below.

Regulation We prepare our financial statements in accordance with SFAS No. 71 for our regulated Vermont service territory and FERC-regulated wholesale business. We are regulated by the PSB, the Connecticut Department of Public Utility and Control and the FERC, with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. Under SFAS No. 71, we account for certain transactions in accordance with permitted regulatory treatment. Regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered in future revenues. In order for a company to report under SFAS No. 71, the company's rates must be designed to recover its costs of providing service and the company must be able to collect those rates from customers. If rate recovery of these costs becomes unlikely or uncertain, whether due to competition or regulatory action, this accounting standard would no longer apply to our regulated operations. Criteria that could give rise to the discontinuance of SFAS No. 71 include: 1) increasing competition that restricts the ability to establish prices to recover specific costs, and 2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. We periodically review these criteria to ensure that the continuing application of SFAS No. 71 is appropriate. If we determine the Company no longer meets the criteria under SFAS No. 71, the accounting impact would be an extraordinary charge to operations of about $38.9 million on a pre-tax basis as of December 31, 2004, assuming no stranded cost recovery would be allowed through a rate mechanism. Based on a current evaluation of the factors and conditions expected to impact future cost recovery, we believe future recovery of our regulatory assets in the State of Vermont for our retail and wholesale businesses is probable.

Discontinued Operations The assets and liabilities of Connecticut Valley are classified as held for sale in the Consolidated Balance Sheets in accordance with SFAS No. 144. In addition, as required by SFAS No. 144, the results of operations related to Connecticut Valley are reported as discontinued operations, and prior periods have been restated to conform to this presentation. For presentation purposes, certain of the Company's common corporate costs, which were previously allocated to Connecticut Valley, have been reallocated back to continuing operations to reflect the sale's impact on continuing operations. These common costs amounted to about $0.2 million in 2004, $1.3 million in 2003 and $1.4 million in 2002, on an after-tax basis. We began to present Connecticut Valley as discontinued operations in the second quarter of 2003 based on the NHPUC's approval of the sale of Connecticut Valley's plant assets and franchise to PSNH. Prior to the second quarter of 2003, Connecticut Valley was reported as a separate segment.

Unregulated Business Results of operations of our unregulated subsidiaries are included in the Other Income and Deductions section of the Consolidated Statements of Income. Catamount's policy is to expense all screening, feasibility and development expenditures associated with determining viability of investments in new projects. Catamount's project costs incurred subsequent to obtaining financial viability are recognized as assets subject to depreciation or amortization. Project viability is obtained when it becomes probable that costs incurred will generate future economic benefits sufficient to recover these costs.

Catamount evaluates the carrying value of its investments on a quarterly basis, or when events and circumstances warrant. The carrying value is considered impaired when the anticipated fair value, based on undiscounted cash flows, is less than the carrying value of each investment. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the investment. In 2004, Catamount determined that its investments in wind projects in Germany were impaired by about $0.2 million based on their current market value, and its Appomattox investment was impaired by about $0.1 million. In 2003, Catamount determined that its investments in Rupert and Glenns Ferry were impaired by amounts that were not significant, and in 2002, Catamount recorded after-tax asset impairment charges of $2.1 million related to certain of its investments. These asset impairments were based on underlying purchase and sale contracts. See Diversification below for additional information.

Revenues Electricity sales to customers are based on monthly meter readings. Estimated unbilled revenues are recorded at the end of each monthly accounting period. In order to determine unbilled revenues, we make various estimates including: 1) energy generated, purchased and resold; 2) losses of energy over transmission and distribution lines; 3) kilowatt-hour usage by retail customer mix — residential, commercial and industrial; and 4) average retail customer pricing rates. We use these estimated amounts to calculate the amount of revenue that has been earned, but not billed, due to the timing of billing cycles used for retail customers.

Income Taxes In accordance with SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109"), we recognize tax assets and liabilities for the cumulative effect of all temporary differences between financial statement carrying amounts and the tax basis of assets and liabilities. Investment tax credits associated with utility plant are deferred and amortized ratably to income over the lives of the related properties. A valuation allowance is recorded to reduce the carrying amounts of deferred tax assets if management determines it is more likely than not such tax assets will not be realized. See Income Tax Issues below for additional information.

Reserve for Loss on Power Contract In accordance with the requirements of SFAS No. 5, we recorded a $14.4 million pre-tax loss accrual related to termination of our long-term power contract with Connecticut Valley in 2004. The contract was terminated as a condition of the Connecticut Valley sale. The loss accrual represented Management's best estimate of the difference between expected future sales revenue, in the wholesale market, for the purchased power that was formerly sold to Connecticut Valley and the cost of purchased power obligations. The estimated life of the power contracts that were in place to supply power to Connecticut Valley extends through 2015.

The loss accrual was estimated based on assumptions about future power prices, the reallocation of power from the state-appointed purchasing agent ("VEPPI") and future load growth. Management will continue to review this estimate at the end of each reporting period and will increase the reserve if the revised estimate exceeds the recorded loss accrual. Additionally, the loss accrual is being amortized on a straight-line basis, as required by GAAP, through 2015. In 2004, we recorded $1.2 million of amortization. The loss accrual and amortization are included in Purchased Power on the

Consolidated Statement of Income in the amount of $13.2 million for the period ended December 31, 2004.

Derivative Financial Instruments We account for various power contracts as derivatives under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted. In April 2003, the Financial Accounting Standards Board ("FASB") issued SFAS No. 149, *Amendment of Statement 133 Derivative Instruments and Hedging Activities*, effective for contracts entered into or modified after June 30, 2003, which amends and clarifies accounting for derivative instruments (collectively "SFAS No. 133"). These statements require that derivatives be recorded on the Consolidated Balance Sheets at fair value. Adoption and application of these statements did not impact our results of operation. At December 31, 2004, we had two power contract derivatives; one valued at quoted market prices and one based on modeling techniques, as described below.

Our long-term contracts for the purchase of power from VYNPC and Independent Power Producers do not meet the definition of a derivative under the requirements of SFAS No. 133 because delivery of power under these contracts is contingent on plant output. Additionally, our long-term power contract with Hydro-Quebec does not meet the definition of a derivative because there is no defined notional amount. See discussion of Power Supply Matters below for additional information related to these contracts.

We have a long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice (Hydro-Quebec Sellback #3). This contract has been determined to be a derivative and is being accounted for under SFAS No. 133. The derivative's year-end estimated fair value was an unrealized loss of $5.7 million in 2004 and an unrealized loss of $1.2 million in 2003. The change in value for 2004 versus 2003 reflects higher forecasted market prices during the contract term. The estimated fair value of this derivative is valued using a binomial tree model and quoted market data when available along with appropriate valuation methodologies.

In November 2004, we entered into two forward sale contracts, one through October 2006 and one through December 2008. The sole purpose of entering into these contracts is to manage price risk from power supply resources used to serve our customers. We enter into forward sale contracts when we forecast excess supply, and to minimize the net costs and risk of serving our customers. Both of these forward sale contracts require the physical delivery of power, but one is contingent upon Vermont Yankee plant output. We have assessed these two contracts and determined that one is a derivative under SFAS No. 133, and the other, due to the unit contingent nature of the contract, is not a derivative. The derivative contract is for delivery of about 15 MW per hour, or a total of 522,544 mWh for the contract term, which extends from November 17, 2004 through December 31, 2008. At December 31, 2004, this contract had an estimated fair value of a $0.4 million unrealized gain. We used over-the-counter quotations or broker quotes at December 31, 2004 to determine the fair value of this contract.

In December 2003, we entered into a forward sale contract for about 148,400 mWh for the period beginning January 1 and ending March 31, 2004, and a forward purchase contract for about 27,100 mWh for the month of April 2004. We entered into these contracts to minimize the net costs and risks of serving customers, including replacement power related to the Vermont Yankee plant's April 2004 scheduled refueling outage. We determined that both contracts did not meet the normal purchase and sale exclusion under SFAS No. 133. At December 31, 2003, the forward sale contract had an estimated fair value of a $0.4 million unrealized gain, and the forward purchase contract had an estimated fair value of a $0.1 million unrealized loss. We used over-the-counter quotations or broker quotes at December 31, 2003 to determine the fair value of these contracts. These derivative contracts were settled by December 31, 2004, and are included in Operating Revenue or Purchased Power on the Consolidated Statement of Income for 2004.

We record derivative contracts on the Consolidated Balance Sheets at fair value. Based on a PSB approved Accounting Order, the changes in fair value are recorded as deferred charges or deferred credits on the Consolidated Balance Sheets depending on whether the fair value is an unrealized loss or gain.

Decommissioning Cost Estimates Accounting for decommissioning costs of nuclear power plants involves significant estimates related to decommissioning costs to be incurred many years in the future. Primary drivers of changes to these estimates include, but are not limited to, increases in projected costs of spent fuel storage, security and liability and property insurance. We own, through equity investments, 2 percent of Maine Yankee, 2 percent of Connecticut Yankee and 3.5 percent of Yankee Atomic. All three plants are completely shut down and are conducting decommissioning activities. We are responsible for paying our equity ownership percentage of decommissioning costs and all other costs for these plants.

As of December 31, 2004, based on the most recent estimates provided, our share of remaining costs to decommission these nuclear units is about $5.8 million for Maine Yankee, $12.6 million for Connecticut Yankee and $4.2 million for Yankee Atomic. These estimates are recorded in the accompanying Consolidated Balance Sheet as nuclear decommissioning liabilities (current and non-current) with a corresponding regulatory asset or other deferred charge. We will adjust associated regulatory assets, other deferred charges and nuclear decommissioning liabilities when revised estimates are provided.

Based on the current regulatory process, we believe our proportionate shares of Maine Yankee, Connecticut Yankee and Yankee Atomic decommissioning costs will be recovered through rates. See Power Supply Matters – Nuclear Generating Companies below for more information.

We are also responsible for our 1.7303 joint-ownership percentage of Millstone Unit #3 decommissioning costs, and we have an external trust to fund our share of decommissioning costs. Contributions to the Trust Fund have been suspended based on the lead owner's representation to various regulatory bodies that the Trust Fund, for its share of the plant, exceeded the Nuclear Regulatory Commission's minimum calculation required. We could choose to renew funding at our discretion as long as the minimum requirement is met or exceeded. Currently, we are recovering these costs in rates. Prior to January 1, 2003, these amounts were applied to reduce certain regulatory assets. Since January 1, 2003, funds collected through retail rates are being recorded as a regulatory liability, which is being addressed in our current rate proceeding.

Pension and Postretirement Benefits We record pension and other postretirement benefit costs in accordance with SFAS No. 87, *Employers' Accounting for Pensions*, and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*. Assumptions are made regarding the valuation of benefit obligations and performance of plan assets. Delayed recognition of differences between actual results and those assumed is a required principle of these standards. This approach allows for systematic recognition of changes in benefit obligations and plan performance over the working lives of the employees who benefit under the plans. The following assumptions are reviewed annually, for a September 30 measurement date:

- Discount Rate – The discount rate is used to record the value of benefits, which are based on future projections, in terms of today's dollars. The selection methodology used in determining the discount rate includes portfolios of "Aa" bonds; all are United States issues and non-callable (or callable with make-whole features) and each issue is at least $50 million. As of September 30, 2004, the discount rate remained at 6 percent.
- Expected Return on Plan Assets ("ROA") – We project the future ROA based principally on historical returns by asset category and

expectations for future returns, based in part on simulated capital market performance over the next 10 years. The projected future value of assets reduces the benefit obligation a company will record. At September 30, 2003, the ROA was 8.25 percent. This rate was used to determine the annual expense for 2004 and the same rate will be used to determine the 2005 expense.

- Rate of Compensation Increase – We project employees' annual pay increases, which are used to project employees' pension benefits at retirement. As of September 30, 2004, the rate of compensation increase remained at 3.75 percent.
- Health Care Cost Trend – We project expected increases in the cost of health care. For measurement purposes, we assumed an 11 percent annual rate of increase in the per capita cost of covered health care benefits for pre-65 claims, and a 10.5 percent increase for post-65 claims, for fiscal 2005. These assumptions were based on expected higher health care costs.
- Amortization of Gains/(Losses) – We can select the method by which gains or losses are recognized in financial results. These gains or losses are created when actual results differ from estimated results based on the above assumptions. We recognize these gains and losses ratably over a five-year period.

Pension costs and cash funding requirements are expected to increase in future years. As of December 31, 2004, the market value of pension plan trust assets was $64.2 million, including $44.3 million in marketable equity securities and $19.9 million in debt securities. Pension plan trust assets were $61.3 million at December 31, 2003, including $42.5 million in marketable equity securities and $18.8 million in debt securities.

Favorable market returns of about $6.6 million in 2004 and about $12.1 million in 2003 helped to offset the adverse effect of sharp declines in the capital markets in 2001 and 2002. Annual pension cost increased by $0.7 million in 2004. Of that amount, $0.6 million is reflected in results of operations and the remaining amount is capitalized.

Postretirement costs also increased by $0.8 million for 2004 due to higher-than-expected medical claims experience. Of that amount, $0.7 million is reflected in results of operations and the remaining amount was capitalized.

Pension and Postretirement Assumption Sensitivity Analysis Fluctuations in market returns may result in increased or decreased pension costs in future periods. The table below shows how a 25-basis-point change in discount rate and expected return on assets would affect pension costs. Any additional decreases in the discount rate would increase the charge to equity by the same amount as the Accumulated Benefit Obligation (ABO).

Pension and Postretirement Assumption Sensitivity Analysis (pre-tax dollars in thousands):

			As of September 30, 2004		
	Effect on 2005 Cost Increase/(decrease)		Effect on ABO Increase/(decrease)		Effect on Charge to Equity Increase/(decrease)
Actuarial Assumption	Pension	Postretirement	Pension	Postretirement	Pension
Discount Rate:					
25-basis-point decrease	$170	$50	$3,076	$600	$1,854
25-basis-point increase	$(170)	$(50)	$(2,960)	$(600)	-
Expected return on assets:					
25-basis-point decrease	$170	$15	-	-	-
25-basis-point increase	$(170)	$(15)	-	-	-

See Note 10 to the Consolidated Financial Statements for additional information related to Pension and Postretirement Benefits.

RESULTS OF OPERATIONS

The following is a detailed discussion of the Company's results of operations for the past three years. This should be read in conjunction with the consolidated financial statements and accompanying notes included in this report.

Consolidated Summary

Consolidated 2004 earnings were $23.8 million, or $1.93 per basic and $1.90 per diluted share of common stock. Consolidated 2003 earnings were $19.8 million, or $1.57 per basic and $1.53 per diluted share of common stock, while consolidated 2002 earnings were $19.8 million, or $1.56 per basic and $1.53 per diluted share of common stock.

In 2004 discontinued operations of Connecticut Valley contributed $12.3 million, or $1.02 per basic and $1.00 per diluted share of common stock, to consolidated earnings. This reflects a $12.3 million after-tax gain on disposal of discontinued operations related to the January 1, 2004 sale of Connecticut Valley's plant assets and franchise. In 2003, discontinued operations of Connecticut Valley contributed $1.4 million, or $.12 per basic and diluted share of common stock, to consolidated earnings, and it contributed $1.5 million, or $.13 per basic and diluted share of common stock, in 2002.

For accounting purposes, components of the Connecticut Valley transaction in 2004 are recorded in both continuing and discontinued operations in the Consolidated Statement of Income. The gain on the asset sale, net of tax, totaled $12.3 million, but we recorded a loss on power costs, net of tax, of $8.4 million relating to termination of the power contract between us and Connecticut Valley. The loss is recorded as Purchased Power in the Consolidated Statement of Income. When the two accounting transactions are combined to assess the total impact of the transaction, the result is a gain of $3.9 million, or $.31 per diluted share of common stock.

The following table provides a reconciliation of 2004 and 2003 diluted earnings per share.

2003 Earnings per diluted share	**$1.53**
Year-over-Year Effects on Earnings:	
Catamount higher earnings	.23
Higher retail and firm sales	.18
IRS tax settlement received in the second quarter of 2004	.09
Higher resale sales	.09
Lower purchased power costs – excluding SFAS No. 5 loss accrual	.08
Higher other operating revenue	.05
Other	.02
Vermont utility allowed rate of return at 11 percent	(.06)
Discontinued operations – 2003	(.12)
Power contract termination related to Connecticut Valley	(.50)
Subtotal	**.06**
Net impact of CVEC sale:	
Gain on discontinued operations	1.00
SFAS No. 5 loss accrual – termination of power contract	(.69)
Subtotal	**.31**
2004 Earnings per diluted share	**$1.90**

The following table provides a reconciliation of 2003 and 2002 diluted earnings per share.

2002 Earnings per diluted share	**$1.53**
Year-over-Year Effects on Earnings:	
Higher resale sales	.43
Federal income tax provision in 2003	.19
Higher retail sales and other operating revenue	.17
Change in cash surrender value of insurance policies	.16
Eversant income in 2003 versus a loss in 2002	.08
Vermont Yankee transaction cost in 2002	.05
Other	.04
Discontinued operations	(.01)
Reversal of environmental reserve in 2002	(.09)
Vermont utility mandated earnings cap	(.09)
Lower equity in earnings	(.16)
Catamount losses (excluding 2003 tax benefit) versus earnings in 2002	(.26)
Higher net power costs	(.51)
Sub-total	**.00**
2003 Earnings per diluted share	**$1.53**

Consolidated Income Statement Discussion

The following includes a more detailed discussion of the components of our Consolidated Income Statements and related year-over-year variances. This discussion follows the order of the Consolidated Income Statements.

Operating revenues The majority of our operating revenues are generated through retail sales from the regulated Vermont utility business. Other resale sales are related to the sale of excess power from our owned and purchased power supply portfolio. Operating revenues and related mWh sales are summarized below:

	mWh Sales			Revenues (in thousands)		
	2004	2003	2002	**2004**	2003	2002
Retail sales:						
Residential	**955,261**	948,278	915,030	**$126,680**	$125,402	$121,420
Commercial	**861,916**	848,413	858,537	**104,153**	102,758	103,073
Industrial	**419,090**	396,081	407,335	**34,755**	33,716	34,206
Other	**5,410**	5,391	5,441	**1,606**	1,599	1,608
Total retail sales	**2,241,677**	2,198,163	2,186,343	**267,194**	263,475	260,307
Resale sales:						
Firm (1)	**4,560**	5,002	2,392	**259**	179	137
RS-2 power contract (2)	**-**	122,685	124,483	**-**	10,409	10,948
Other	**548,325**	567,921	442,187	**26,507**	24,587	15,806
Total resale sales	**552,885**	695,608	569,062	**26,766**	35,175	26,891
Other revenues	**-**	-	-	**8,240**	7,364	7,192
Total	**2,794,562**	2,893,771	2,755,405	**$302,200**	$306,014	$294,390

(1) Based on FERC filed tariffs

(2) The wholesale power contract between the Company and Connecticut Valley was terminated on January 1, 2004. See Discontinued Operations above

The average number of retail customers is summarized below:

	2004	2003	2002
Residential	**128,665**	127,881	126,358
Commercial	**20,551**	19,922	19,481
Industrial	**37**	38	37
Other	**171**	173	175
Total number of retail customers	**149,424**	148,014	146,051

Comparative changes in Operating revenues are summarized below:

	2004 vs. 2003	2003 vs. 2002
Retail revenues:		
Change in mWh volume	**$4,524**	$2,237
Change in price (customer mix)	**(805)**	931
Subtotal	**3,719**	3,168
Firm resale sales	**80**	42
RS-2 power contract	**(10,409)**	(539)
Other resale sales	**1,920**	8,781
Other revenues	**876**	172
Increase (decrease) in Operating Revenues	**$(3,814)**	$11,624

2004 vs. 2003

Operating revenues decreased $3.8 million, or 1.3 percent, in 2004 compared to 2003 due to the following factors:

- Retail and firm sales increased $3.8 million primarily due to higher sales volume. These sales are affected by weather and economic conditions. Lower average industrial prices due to higher usage per customer partially offset the favorable effect of higher sales volume.
- The January 1, 2004 termination of the power contract with Connecticut Valley decreased resale revenue by $10.4 million, but made about 123,000 mWh available for use by the Company or for other resale sales. The effects of the contract termination are reflected as higher resale revenue or lower short-term purchases.
- Other resale revenue increased $1.9 million due to higher average market prices, partly offset by lower sales volume. The lower volume resulted from fewer mWh available for resale due to scheduled nuclear plant outages at Vermont Yankee and Millstone Unit #3 in the second quarter of 2004, and a 19-day unscheduled outage at the Vermont Yankee plant that ended July 7, 2004. The lower volume was partially offset by termination of the Connecticut Valley power contract.
- Other operating revenue increased $0.9 million primarily due to service billings related to mutual aid work in Florida. Revenue related to fees charged for use of utility poles, referred to as pole attachments, increased as a result of a field inventory completed in 2003, and transmission revenue also increased slightly.

2003 vs. 2002

Operating revenues increased $11.6 million, or 4 percent, in 2003 compared to 2002 due to the following factors:

- Retail and firm sales increased $3.2 million primarily due to a 1 percent increase in sales volume. These sales are affected by weather and economic conditions. In 2003, colder weather in the first quarter increased residential sales volume, while relatively weak economic conditions decreased sales volume for our Commercial and Industrial customers.
- Sales to Connecticut Valley under the RS-2 power contract decreased $0.5 million due to lower volume and lower unit costs under the contract.
- Other resale sales increased $8.8 million due to higher rates for contract sales and wholesale market prices in ISO-New England and more power available for resale in 2003. The higher contract rates were related to a forward sale in 2003 in which we sold about 306,000 mWh during the period February through December 2003. In 2002 most of our resale sales were made at ISO-New England market prices. We had more mWh available for resale primarily due to increased output from Vermont Yankee and Millstone, as neither plant was off-line for scheduled refueling and maintenance in 2003. Also, Vermont Yankee had a second quarter 2002 unscheduled outage for fuel rod repairs.
- Other operating revenue increased about $0.1 million.

Purchased Power

Most of our power purchases are made under long-term contracts. These contracts, power supply management and nuclear investments are described in more detail in Power Supply Matters below. The primary components of purchased power expense are as follows (in thousands):

	For the years ended December 31		
	2004	2003	2002
VYNPC (a)	**$58,704**	$65,581	$60,228
Hydro-Quebec	**56,943**	57,525	59,182
Independent Power Producers (IPPs)	**20,252**	19,115	18,137
Subtotal long-term contracts	**135,899**	142,221	137,547
Short-term purchases	**15,595**	7,440	7,820
Miscellaneous purchases	**80**	64	57
SFAS No. 5 loss accrual (net of amortizations)	**13,155**	-	-
Nuclear decommissioning costs	**2,142**	1,922	1,944
Accounting (deferrals) amortizations (b)	**(1,220)**	1,347	(4,938)
Total purchased power	**$165,651**	$152,994	$142,430

(a) Includes about $0.4 million in 2004 and in 2003 related to insurance refunds that we deferred per PSB approval. See Note 1 - Summary of Significant Accounting Policies.

(b) Accounting (deferrals) amortizations are based on permitted regulatory accounting guidance in which certain incurred costs, typically treated as expenses by unregulated entities, are deferred and expensed when recovered in future periods. Such accounting treatment allows for the matching of expenses with revenues over the period of recovery, and for purchased power are typically related to incremental replacement energy costs that result from nuclear plant outages, and for 2002 also include items related to sale of the Vermont Yankee nuclear power plant. For year-over-year comparison purposes these items are included in the variance explanations for individual sources as described below.

The related mWh purchases from these sources are summarized below:

	2004	2003	2002
VYNPC	**1,343,629**	1,547,771	1,351,872
Hydro-Quebec	**790,017**	826,104	895,595
IPPs	**172,210**	164,917	159,113
Short-term purchases	**226,782**	108,228	178,419
Miscellaneous purchases	**4,400**	2,813	2,860
Total mWh	**2,537,038**	2,649,833	2,587,859

The related unit price ($/mWh) of these purchases are summarized below:

	2004	2003	2002
VYNPC	**$43.69**	$42.37	$44.55
Hydro-Quebec	**$72.08**	$69.63	$66.08
IPPs	**$117.60**	$115.91	$113.99
Short-term purchases	**$68.77**	$68.74	$43.83
Miscellaneous purchases	**$18.18**	$22.75	$19.93

2004 vs. 2003

Purchased power expense increased $12.7 million, or 8.3 percent, in 2004 compared to 2003 as a result of the following factors:

- In the first quarter of 2004, in accordance with SFAS No. 5, we recorded a $14.4 million pre-tax loss accrual related to termination of the power contract with Connecticut Valley. The loss accrual represents Management's best estimate of the difference between expected future sales revenue, in the wholesale market, for the purchased power that was formerly sold to Connecticut Valley and the cost of purchased power to be incurred to realize those future sales. In accordance with GAAP, the loss accrual is being amortized on a straight-line basis through 2015, which represents the estimated life of our power contracts that were in place to source the Connecticut Valley power contract. In 2004, amoritizations reduced purchased power expense by $1.2 million, for a net impact of $13.2 million.

- Short-term purchases, which include purchases from ISO-New England and third parties in New England, increased $6.6 million primarily due to replacement energy for the Millstone Unit #3 refueling outage and the Vermont Yankee outages. We deferred about $1.2 million for incremental replacement energy costs related to the Millstone Unit #3 refueling outage and Vermont Yankee unscheduled outage, compared to $0.4 million of amortizations of replacement energy deferrals related to a Millstone Unit #3 2002 refueling outage. These deferrals and amortizations are included in Accounting (deferrals) amortizations in the table above.
- IPP purchases increased $1.2 million, primarily due to higher output from these facilities and higher rates. The majority of IPPs are hydro facilities and output is based on weather conditions that affect water flow.
- Nuclear decommissioning costs are related to our share of Maine Yankee, Connecticut Yankee and Yankee Atomic decommissioning costs. Our share of decommissioning costs increased $0.2 million, due to changes in FERC-approved rates in 2004. The amounts in the table above are reflected net of accounting deferrals, which are described in more detail in Power Supply Matters – Nuclear Generating Companies below.
- Vermont Yankee purchases decreased $7.9 million, excluding a 2003 refund. About $6.9 million of the decrease is primarily due to a scheduled refueling outage and a 19-day unscheduled outage in 2004 versus no plant outages in 2003. Also in 2003, Vermont Yankee received a refund related to defective fuel rods that caused an unscheduled outage in 2002. For accounting purposes our share of the refund, about $1 million, was used to decrease deferred charges related to incremental replacement energy costs resulting from the outage. The refund is included in Vermont Yankee purchases, while the offset is included in Accounting (deferrals) amortizations in the table above.
- Hydro-Quebec purchases decreased $0.6 million due to fewer deliveries under the Hydro-Quebec contract resulting from interconnection deficiencies.

2003 vs. 2002

Purchased power expense increased $10.6 million, or 7.4 percent, in 2003 compared to 2002 as a result of the following factors:

- An $11.6 million increase in Vermont Yankee-related costs primarily resulting from higher plant output in 2003, which increased purchases by about $8.2 million. Other factors that resulted in a net $3.4 million increase when comparing 2003 versus 2002 included a $2.2 million reduction in 2002 power costs due to state tax benefits realized by Vermont Yankee that were passed on to the Vermont Yankee sponsors and $5.2 million of sale-related deferrals in 2002, offset by about $4 million due to elimination of amortizations for Vermont Yankee nuclear refueling outages.
- A $1 million increase in purchases from IPPs due to higher volume and rates.
- A $1.7 million decrease in purchases from Hydro-Quebec due to reduced deliveries resulting from interconnection deficiencies.
- A $0.4 million decrease in short-term purchases, including the impacts of accounting deferrals and amortizations of replacement energy costs in 2003 and 2002. The variance when comparing 2003 versus 2002 is attributed to the following factors: 1) a $2 million increase in ISO-New England capacity charges due to credits we received in 2002 for our share of revenues from the ISO-New England capacity deficiency pool, with no comparable credits in 2003; 2) a $1.3 million decrease in short-term and spot energy purchases; 3) a $1 million decrease in installed capacity purchases due to lower rate and volume; and 4) a $0.1 million decrease in other costs.

Operating Expenses

Operating expenses represent costs incurred to support our core business. The following table provides the variances in income statement line items for Operating Expenses on the Consolidated Statements of Income for the past two years (dollars in thousands).

	2004 over/(under) 2003		2003 over/(under) 2002	
	Amount	Percent	Amount	Percent
Operation				
Purchased power (explained above)	$12,657	8.3%	$10,564	7.4%
Production and transmission	(642)	(2.5)	541	2.1
Other operation	3,997	8.6	3,278	7.5
Maintenance	19	0.1	(661)	(3.8)
Depreciation	115	0.7	(537)	(3.3)
Other taxes, principally property taxes	249	1.9	507	3.9
Taxes on income	(9,069)	(89.6)	(884)	8.0
Total operating expenses	**$7,326**	**2.6%**	$12,808	4.8%

Production and transmission: These expenses are primarily associated with generating electricity from our wholly and jointly owned units, and transmission of electricity. The $0.6 million decrease in 2004 is primarily due to lower output from jointly owned units and lower transmission costs.

Other operation: These expenses are primarily related to operating activity such as customer accounting, customer service, administrative and general and other operating costs incurred to support our core business. The $4 million increase includes about $1.3 million related to reducing the Vermont utility's earnings to achieve an 11 percent return on equity. In 2004, based on a PSB-approved Accounting Order, this amounted to a $3.8 million pre-tax expense. In 2003, per the July 2001 PSB-approved rate order, this amounted to a $2.5 million pre-tax expense. In both years, we recorded related regulatory liabilities for these amounts. See Vermont Retail Rates discussion above for additional information.

The remaining $2.7 million increase resulted from higher employee-related costs (pension and medical), higher pole attachment expenses that are offset in Operating Revenue above, higher professional services costs related to Sarbanes-Oxley project readiness, the rate case and general legal expenses, and higher bad debt expense related to a second quarter 2004 customer bankruptcy. These increased costs are partially offset by the favorable impact of an insurance settlement received in the second quarter of 2004 and the favorable impact of conservation and load management amortizations that ended in 2003.

The $3.3 million increase for 2003 versus 2002 is primarily related to the Vermont utility's mandated earnings cap, which resulted in a pre-tax expense of $2.5 million in 2003 to achieve the mandated earnings cap. Other factors affecting 2003 versus 2002 included a $1.7 million reversal of environmental reserves in 2002, which results in an unfavorable variance when comparing 2003 versus 2002, and higher employee-related costs, offset by internal cost cutting efforts, and lower bad debt reserve adjustments in 2003 compared to 2002 due to several customer bankruptcies in 2002.

Maintenance: These expenses are primarily related to costs associated with maintaining our electric distribution system. There was no significant variance for 2004 versus 2003 or for 2003 versus 2002.

Depreciation: We use the straight-line remaining-life method of depreciation. There was no significant variance for 2004 versus 2003 or for 2003 versus 2002.

Other taxes, principally property taxes: This is primarily related to property taxes and payroll taxes. There was no significant variance for 2004 versus 2003 or for 2003 versus 2002.

Taxes on Income: Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences and changes in valuation allowances for the periods. The effective tax rate was 3.1 percent for 2004, 32 percent for 2003 and 37.8 percent for 2002. The effective tax rate decreased significantly in 2004 primarily due to tax benefits associated with the sale of certain of Catamount's equity investments in 2004. The effective tax rate for 2003 decreased when compared to 2002 primarily due to a decrease in the valuation allowance. See Income Tax Matters below and Note 11 to the Consolidated Financial Statements for additional information related to Income Taxes.

During 2004, we received three income tax refunds totaling $0.9 million (exclusive of interest). One refund related to an appeal of an overpayment from a prior federal income tax audit for the tax years 1982 through 1984. The proceeds from the settlement included a federal income tax refund of $0.5 million. The other two refunds related to an appeal of federal and state income tax overpayments for 2000. The proceeds from the settlements included a federal income tax refund of $0.3 million and a state refund of $0.1 million. We also decreased the estimate for tax contingencies by $0.3 million due to a reduction in potential tax liabilities.

On June 7, 2004, the State of Vermont enacted legislation that reduced the state income tax rate from 9.75 percent to 8.9 percent effective January 1, 2006, and from 8.9 percent to 8.5 percent effective January 1, 2007. Deferred tax assets and liabilities were adjusted in 2004 to reflect the enacted income tax rate change. This rate change reduced regulatory tax assets by about $1.4 million, and increased income tax expense by about $0.2 million. The decrease in regulatory assets was primarily caused by a decrease in operating deferred tax liabilities. The increase in tax expense was primarily caused by a reduction in non-operating deferred tax assets.

In 2004, taxes on income also included a $5.3 million benefit related to the loss accrual resulting from the termination of the power contract with Connecticut Valley as described in Discontinued Operations above.

Other Income and Deductions

These items are related to the non-operating activities of the utility business and the operating and non-operating activities of our non-regulated businesses. The following table provides the variances in income statement line items for Other Income and Deductions on the Consolidated Statements of Income for the past two years (dollars in thousands).

	2004 over/(under) 2003		2003 over/(under) 2002	
	Amount	Percent	Amount	Percent
Equity in earnings of affiliates	**$(576)**	**(32.0)%**	$(2,108)	(53.9)%
Equity in earnings of non-utility investments	**(2,142)**	**(33.7)**	(5,288)	(45.4)
Gain on sale of non-utility investments	**2,518**	**100.0**	-	-
Allowance for equity funds during construction	**62**	**71.2**	16	22.5
Other income	**1,634**	**22.7**	397	5.8
Other deductions	**1,600**	**14.7**	6,027	35.7
Benefit (provision) for income taxes	**(777)**	**(52.9)**	1,552	1,892.7
Total other income and deductions	**$2,319**	**38.1%**	$596	10.9%

Equity in earnings of affiliates: These are related to our equity investments, primarily VELCO and VYNPC. The $0.6 million decrease is primarily related to lower VYNPC interest income. VYNPC's interest income was higher in 2003 due to sale proceeds that were not disbursed until October 2003. The $2.1 million decrease for 2003 versus 2002 was primarily related to state tax benefits realized by Vermont Yankee in 2002 as a result of the sale of the plant. These tax benefits were passed through to the plant owners, partly in the form of higher equity in earnings, with the remaining through lower purchased power expense. The July 2002 sale of the Vermont Yankee plant has reduced our ongoing equity in earnings from that investment.

Equity in earnings of non-utility investments: These are related to Catamount's equity investments in non-regulated independent power projects. The $2.1 million decrease is primarily due to lower earnings from its investments in Glenns Ferry, Rupert, Rumford and Catamount Energy Limited. The $5.3 million decrease for 2003 versus 2002 was primarily due to the October 2002 sale of its Heartlands investments, lower earnings from its Rumford investment due to an accelerated depreciation adjustment and lower earnings from its investments in Appomattox and Ryegate. See Diversification below.

Gain on sale of non-utility investments: In 2004, Catamount completed the sale of its Glenns Ferry and Rupert investments and the sale of its Fibrothetford note receivable and equity investment. These asset sales amounted to a pre-tax gain of about $2.5 million in 2004. There were no asset sales in 2003, and in 2002 asset sales approximated book value, therefore there were no associated gains or losses. See Diversification below.

Allowance for equity funds used during construction: This is the cost of equity financing during construction projects. It is capitalized as part of major utility plant projects when costs applicable to such construction work in progress have not been included in rate base through ratemaking proceedings.

Other income: These income items include interest and dividend income, interest on temporary investments and non-utility notes receivable, Catamount's operating revenue, regulatory asset carrying costs, amortization of contributions in aid of construction and various miscellaneous other income items.

The $1.6 million increase is primarily due to higher interest income on temporary investments and available-for-sale securities, resulting from investment of cash proceeds from the Connecticut Valley sale and other cash on hand in early 2004. Other factors include higher interest and dividend income primarily related to interest received as part of an IRS tax settlement and higher non-utility revenue due to fees associated with Catamount's United Kingdom development efforts, offset by lower miscellaneous other income.

The $0.4 million increase for 2003 versus 2002 is primarily related to higher interest on non-utility notes receivable, higher non-operating rental income, higher regulatory asset carrying costs and higher miscellaneous other income, offset by lower non-utility revenue due to realized development revenue in 2002 upon the sale of one of Catamount's investments.

Other Deductions: These deductions include Catamount's operating expenses, asset impairment charges, supplemental retirement benefits and insurance, including changes in the cash surrender value of life insurance policies, and miscellaneous other deductions.

The $1.6 million decrease in 2004 is primarily related to lower Catamount operating expenses due to lower business development and other consulting expenses. Business development expenses were lower as a result of entering into development arrangements with third parties in 2004. Other consulting expenses were lower primarily due to the expensing in 2003 of previously capitalized costs related to the private equity placement efforts.

The $6 million decrease for 2003 versus 2002 was primarily related to lower life insurance expense resulting from a significant increase in the cash surrender value of certain life insurance policies due to financial market results, and various one-time items in 2002, which result in a favorable variance when comparing 2003 versus 2002. These one-time items included $2.7 million pre-tax asset impairment charges in 2002 related to Catamount's investments that were sold in the fourth quarter of 2002, a one-time payment of $1 million to the non-Vermont owners related to closing the Vermont Yankee sale, and lower Eversant operating expense due to discontinuance of its efforts to pursue unregulated business opportunities.

Benefit (provision) for income taxes: Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences and changes in valuation allowances for the periods. The increase for 2004 is primarily due to higher Catamount earnings related to the sales of investment interests. In the third quarter of 2003 there was also a $2.3 million reduction in income tax valuation allowances associated with previously recorded equity losses from asset impairments. In 2003, the consolidated federal income tax provision reflected a benefit due to realization of capital gains on the Connecticut Valley sale, which afforded Catamount the opportunity to reduce tax valuation allowances. Also see Income Tax Matters below.

Interest Expense

Interest expense includes interest on long-term debt and other interest of the utility business and our unregulated businesses, and allowance for borrowed funds during construction. The following table provides the variances in income statement line items for Interest Expense on the Consolidated Statements of Income for the past two years (dollars in thousands).

	2004 over/(under) 2003		2003 over/(under) 2002	
	Amount	Percent	Amount	Percent
Interest on long-term debt	$(2,306)	(20.5)%	$(1,295)	(10.6)%
Other interest	444	81.1	579	1,853.0
Allowance for borrowed funds during construction	(19)	(50.0)	(3)	(8.6)
Total interest expense	**$(1,881)**	**(16.0)%**	$(719)	(5.8)%

Interest on long-term debt: The $2.3 million decrease in 2004 includes $1.3 million resulting from lower long-term debt and $1 million resulting from lower interest rates due to the August 2004 bond refinancing. The $1.3 million decrease for 2003 versus 2002 is primarily related to lower long-term debt. See Financing above for additional information.

Other interest expense: The $0.4 million increase is primarily related to the reclassification of dividends on mandatorily redeemable preferred stock to interest expense as described in Dividends on preferred stock below, and increased carrying costs on regulatory liabilities. This was partially offset by the IRS tax settlement described above. The $0.6 million decrease for 2003 versus 2002 is primarily related to Eversant's 2002 settlement of an IRS audit resulting in the reversal of a related interest expense accrual previously recorded in the fourth quarter of 2001.

Allowance for borrowed funds during construction: This is the cost of debt financing during construction projects that we capitalize as part of the cost of major utility plant projects when costs applicable to such construction work in progress have not been included in rate base through the ratemaking process. There was no significant variance in these expenses for 2004 versus 2003 or 2003 versus 2002.

Discontinued Operations

On January 1, 2004, Connecticut Valley completed the sale of substantially all of its plant assets and its franchise to PSNH. See Discontinued Operations.

Dividends on preferred stock

Preferred stock dividends decreased by $0.8 million in 2004 primarily related to SFAS No. 150, *Accounting for Certain Financial Instruments with the Characteristics of Both Liabilities and Equity* ("SFAS No. 150"). This statement established standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity. We implemented the income statement impacts of SFAS No. 150 in 2004, and as a result about $0.7 million of dividends on the 8.3 percent series mandatorily redeemable preferred stock were reclassified from Preferred Stock Dividend Requirements to Interest Expense.

POWER SUPPLY MATTERS

Sources of Energy Our power supply portfolio includes a mix of base load, dispatchable and energy-constrained schedulable resources. A breakdown of energy sources is shown below:

	2004	2003	2002
Nuclear generating companies	**46%**	50%	46%
Canadian hydro contract	**27**	27	30
Company-owned hydro and thermal	**6**	6	6
Jointly owned units	**7**	8	7
Independent power producers	**6**	5	5
Other	**8**	4	6
	100%	100%	100%

Our joint-ownership interests include 1.73 percent in Unit #3 of the Millstone Nuclear Power Station, 20 percent in Joseph C. McNeil, a 53-MW wood-, gas- and oil-fired unit, and 1.78 percent joint-ownership in Wyman #4, a 619-MW oil-fired unit. Our wholly owned units include 20 hydroelectric generating units, two oil-fired gas turbines and one diesel peaking unit with a combined nameplate capability of 73.6 MW.

We have a long-term power contract with Hydro-Quebec and a long-term power contract for purchase of about 35 percent of Vermont Yankee plant output. Combined, these contracts contributed about 84 percent of our total energy (mWh) purchases in 2004, compared to 90 percent in 2003 and 87 percent in 2002. We are also required to purchase power from various Independent Power Producers ("IPPs") under long-term contracts. These contracts are discussed in more detail below.

Power Contract Commitments

Hydro-Quebec We purchase varying amounts of power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract and related contracts negotiated between us and Hydro-Quebec that altered the terms and conditions of the original contract by reducing the overall power requirements and related costs. Our purchases under these contracts extend through 2016. There are specific contractual provisions that provide that in the event any VJO member fails to meet its obligation under the contract with Hydro-Quebec, the remaining VJO participants, including the Company, must "step-up" to the defaulting party's share on a pro rata basis. As of December 31, 2004, our obligation is about 46 percent of the total VJO Power Contract, which translates to about $663 million, on a nominal basis, over the contract term. See Note 13 to the Consolidated Financial Statements for further discussion of this contract.

In January 2004, Hydro-Quebec notified the VJO that, due to interconnection deficiencies, it would not be able to reschedule energy not delivered during the 2002 – 2003 and 2003 – 2004 contract years. We continue to work with Hydro-Quebec to minimize future interconnection deficiencies through various scheduling modifications and use of interconnection facilities. Our estimated cost of energy and capacity under the existing contracts with Hydro-Quebec are $58.5 million in 2005, $62.1 million in 2006, $62.3 million in 2007, $63.1 million in 2008 and $64 million in 2009.

VYNPC We have a 35 percent entitlement in Vermont Yankee plant output sold by Entergy ("ENVY") to VYNPC, through a long-term power purchase contract with VYNPC. One remaining secondary purchaser continues to receive a small percentage of our entitlement, reducing our entitlement to about 34.83 percent. The long-term contracts between VYNPC and the entitlement holders and between VYNPC and ENVY became effective on July 31, 2002, the same day that the Vermont Yankee nuclear plant was sold to ENVY. We no longer bear the operating costs and risks associated with running the plant or the costs and risks associated with the eventual decommissioning of the plant. ENVY has no obligation to supply energy to VYNPC over the amount the plant is producing, so entitlement holders receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating.

The PPA through which VYNPC purchases power from ENVY and in turn sells to its sponsors includes prices that generally range from 3.9 cents to 4.5 cents per kilowatt-hour through March 2012. Effective November 2005, the contract prices are subject to a "low-market adjuster" that protects us and our power consumers if power market prices drop significantly. The low-market adjuster is a mechanism in which the PPA base contract price for each billing month is compared to a 12-month average (ending in same billing month) of hourly market prices as defined in the PPA. If the 12-month average market price is less than 95 percent of the base PPA contract price, then 105 percent of the 12-month average market price will be used for the billing month. The low-market adjusted price cannot exceed the base PPA contract price. If the market prices rise, however, contract prices are not adjusted upward. In addition to PPA charges, VYNPC's billings to the sponsors include certain of its residual costs of service through a FERC tariff to the VYNPC sponsors. The PPA is expected to result in decreased costs over the life of the PPA when compared to the projected cost of continued ownership of the plant.

Purchases from VYNPC amounted to about $58.3 million in 2004, $65.2 million in 2003 and $60.2 million in 2002, and are included in Purchased Power on the Consolidated Statements of Income. Accounts Payable to VYNPC amounted to $5.8 million at December 31, 2004 and $4.6 million at December 31, 2003. Future VYNPC purchases are expected to be $57.1 million in 2005, $61.1 million in 2006, $58.0 million in 2007, $59.7 million in 2008 and $65.8 million in 2009.

In 2003, ENVY sought PSB approval to increase generation at the Vermont Yankee plant by 110 megawatts. Our purchases from VYNPC will not be affected by increased generation but our entitlement percentage of plant output will decrease about 29 percent. On March 15, 2004, the PSB approved the proposal, but its approval was conditioned on ENVY providing an outage protection indemnification ("Ratepayer Protection Proposal" or "RPP") for us and GMP in case the uprate causes temporary reductions in output that reduce our value of the PPA. Our maximum right to indemnification under the RPP is about $2.8 million, and will be in place for three years to cover any uprate-related reductions in output.

Plant output has been reduced since the April 2004 scheduled refueling outage, and will continue until ENVY receives NRC approval for the uprate. Our 182 MW entitlement was reduced by an average of about 4 MW during this period. The financial effect of such a reduction will be covered under the terms of the RPP. In 2004, ENVY made a payment of an undisputed amount under the RPP and we are seeking agreement with ENVY on a final payment.

On June 18, 2004, an incident that caused a fire at the Vermont Yankee plant's transformer caused the plant to shut down for about 19 days. We deferred about $0.8 million of incremental replacement energy costs incurred as a result of the outage, per the PSB's preliminary approval of our request for an Accounting Order. The Final Accounting Order is being addressed as part of our rate case. We believe the plant went off line due to problems associated with uprate-related improvements made by ENVY, and have sought about $0.8 million from ENVY to cover the incremental replacement energy costs resulting from the outage. ENVY contends that the problem would have occurred regardless of the uprate. We engaged in discussions with ENVY relating to settlement of this dispute in accordance with the RPP. Having failed to reach a settlement with ENVY, we petitioned the PSB for resolution. On February 18, 2005, the PSB held a prehearing conference and set a schedule that provides for resolution in the third quarter of 2005. We and ENVY agreed to remain in settlement discussions relating to this matter.

In April 2004, in response to an NRC inspection conducted during the Vermont Yankee plant's scheduled refueling outage, ENVY reported that two short spent fuel rod segments were not in what ENVY believed to be their documented location in the spent fuel pool. According to ENVY, in 1979 the rods were placed in a special stainless steel container in the spent fuel pool. After initial document review and visual inspection of the spent fuel pool, ENVY did not locate the fuel rod segments. On May 5, 2004, ENVY notified VYNPC that based on the terms of the Purchase and Sale Agreement dated August 1, 2001, and facts at the time, it was their view that costs associated with the spent fuel rod segment inspection effort were the responsibility of VYNPC. On May 20, 2004, VYNPC responded that based on the information at the time there was no basis for ENVY's claim. Subsequently, ENVY's continuing documentation review led to the discovery of the fuel rod segments in a container in the spent fuel pool. The NRC has begun its own investigation into ENVY's accounting for these segments. We cannot predict the outcome of this matter at this time.

Nuclear industry practice typically is to maintain the capacity to off-load the entire active nuclear fuel core into the spent fuel pool as a safety measure; this is called maintaining full core discharge capability. ENVY anticipated that to maintain full core discharge capability, dry cask storage of spent nuclear fuel will be needed at the Vermont Yankee plant by late 2008 based on current operations or as early as 2007 if the NRC does grant permission to uprate the plant output. ENVY requires enabling legislation from the Vermont State Legislature and PSB approval for dry cask storage.

Independent Power Producers ("IPPs") We purchase power from a number of IPPs who own qualifying facilities under the Public Utility Regulatory Policies Act of 1978. These qualifying facilities produce energy primarily using hydroelectric and biomass generation. Most of the power comes through a state-appointed purchasing agent, VEPP Inc. ("VEPPI"), which assigns power to all Vermont utilities under PSB rules. In 2004, IPP purchases accounted for 6.8 percent of the Company's total mWh purchased and 12.2 percent of purchased power expense. Purchases from IPPs are expected to be $18.7 million in 2005, $18.2 million in 2006, $19.1 million in 2007, $19.3 million in 2008 and $17.8 million in 2009. These amounts reflect annual savings of about $0.4 million related to the IPP settlement that is described in Note 13 to the Consolidated Financial Statements.

Power Supply Management We engage in short-term purchases and sales in the wholesale markets administered by the New England Independent System Operator ("ISO-New England") and with other third parties, primarily in New England, to minimize net power costs and risks to our customers. We enter into forward purchase contracts when additional supply is needed, such as for a Vermont Yankee nuclear plant refueling outage. We enter into forward sale contracts when we forecast excess supply and to minimize the net cost and risks of serving customers. On an hourly basis, power is sold or bought through ISO-New England to balance our resource output and load requirements, through the normal settlement process. On a monthly basis, we aggregate the hourly sales and purchases through ISO-New England and record them as Operating Revenue or Purchased Power, respectively.

Our long-term power forecast shows that energy purchase and production amounts exceed our load requirements. This is partly attributed to the January 1, 2004 termination of the power contract with Connecticut Valley, which made an annual average of about 15 MW previously used to source the contract available for load requirements or for resale. Because of this general increase, in November 2004, we entered two separate forward sale transactions, one through October 2006 and one through December 2008. Both contracts require physical delivery of power, but one is contingent upon Vermont Yankee plant output. We have assessed these two forward sale contracts and determined that one is a derivative under SFAS No. 133, and the other, due to the unit contingent nature of the transaction, is not a derivative. Our accounting for derivative power contracts is described in more detail in Critical Accounting Policies and Estimates above.

Based on existing commitments and contracts, we expect that net purchased power and production fuel costs will average about $122 million to $132 million per year for the years 2005 through 2009. These projections are dependent, in part, upon wholesale power market prices. Increases in the wholesale price should generally reduce our net power costs, while decreases should generally increase net costs.

We continue to monitor, and adapt to, changes to New England wholesale power markets and open access transmission systems. In March 2003, ISO-New England implemented Standard Market Design ("SMD"), a significant step to restructuring the wholesale energy markets in the Northeast. We use both the day-ahead and real-time markets in ISO-New England. The day-ahead energy market has generally seen slightly higher energy prices and lower price volatility than the real-time energy market. Operating reserve prices and their volatility have also generally been lower in the day-ahead market. We apply continuous improvement management techniques in managing our power supply resources and load obligations in SMD to minimize the net cost of power supply and related risks.

Beginning May 1, 2004, we began to settle our power accounts with ISO-New England on a standalone (direct) basis. Up until this time, all Vermont utilities were settled at ISO-New England, and VELCO then performed the settlement within Vermont. With changes in power markets and NEPOOL/ISO rules and procedures, many of the benefits of a single Vermont settlement have disappeared, and direct settlement now provides advantages to us in terms of efficiency and cost savings.

Transmission-related matters We operate our transmission system under an open-access tariff, pursuant to FERC Order No. 888. In 1999, FERC began work to amend regulations and facilitate formation of Regional Transmission Organizations ("RTOs"), and in 2001, FERC issued Order No. 2000 for that purpose. Since that time, we have participated in numerous related proceedings, including discussions to create an Open Access Transmission Tariff and Transmission Owners Agreement to govern the provision of transmission services.

In July 2002, FERC issued a Standard Market Design Notice of Proposed Rulemaking to establish nationwide rules for power markets and RTOs. The rulemaking was designed to separate governance and operation of the transmission system from generation companies and other market participants and facilitate power markets with common rules.

On October 31, 2003, ISO-New England and the transmission-owning entities in New England, including us, filed a joint proposal with FERC to create an RTO for New England. That filing received conditional approval from FERC, and the RTO parties have reached agreement in principle to resolve certain outstanding issues with NEPOOL. The parties have requested that FERC expedite its decision processes on remaining issues, in particular, the rate of return that will be permitted on transmission investments.

On March 24, 2004, FERC conditionally approved the RTO filing. The RTO parties submitted a compliance filing to FERC in December 2004. In the filing, the Highgate facilities are classified as PTF with a five-year phase-in of Regional Network Service ("RNS") reimbursement treatment. At the end of the phase-in period, our net costs will be based on our load ratio rather than our ownership share of the facilities. This change is expected to significantly decrease our costs for RNS service related to that facility. Apart from the new RTO, we expect other transmission costs will increase due to growth in new transmission facilities in New England. The RTO began operations on February 1, 2005. Our share of savings related to the Highgate facilities are expected to be about $0.6 million in 2005, $1.0 million in 2006, $1.4 million in 2007, $1.7 million in 2008 and $2.1 million in 2009. At this time, we are not able to predict the impact of other transmission costs related to the RTO.

Transmission plays a significant role in the competitive wholesale market. At this time, much of the cost of New England's existing and new high-voltage transmission system (115 kV looped facilities) is shared by all New England utilities. VELCO is planning several significant upgrades, which have been approved by NEPOOL for shared cost treatment. Vermont has traditionally had higher-than-average transmission costs. The current approach provides cost and reliability benefits in providing service to our customers, because our load share is a small fraction of New England's load, and the facilities upgrades VELCO is planning improve the reliability and efficiency of the transmission network. We will pay a share of such projects elsewhere in New England, but the net economic effect is expected to be beneficial. Also, better reliability elsewhere in the region benefits Vermont's reliability because of the highly integrated nature of New England's high-voltage network. If other future transmission facilities do not qualify for cost sharing, those costs will be charged only to the requesting entity and our share of such costs will be affected by FERC-approved cost-allocation rules contained in VELCO's and our tariffs and agreements.

VELCO bills us on a monthly basis for transmission and administrative costs associated with power and transmission services; these billings include various credits such as those from ISO-New England under the NEPOOL Open Access Transmission Tariff ("NOATT"). Such billings amounted to $6.3 million in 2004, $12.0 million in 2003 and $12.6 million in 2002, and are reflected as production and transmission expenses in the accompanying Consolidated Statements of Income. Prior to May 2004, VELCO also billed us for our share of NOATT charges, which are now billed directly to us from ISO-New England. Of the amounts billed to us by VELCO, about $5.3 million in 2004, $10.7 million in 2003 and $11.7 million in 2002 are included in VELCO's revenues. Accounts payable to VELCO amounted to $4.8 million at December 31, 2004 and $6.2 million at December 31, 2003.

Wholly Owned Generating Units We own and operate 20 hydroelectric generating units, two oil-fired gas turbines and one diesel peaking unit with a combined nameplate capability of 73.6 MW.

We are in the process of relicensing or preparing to license six separate hydroelectric projects under the Federal Power Act. These projects, some of which are grouped together under a single license, represent about 24.5 MW, or 54.8 percent, of our total hydroelectric nameplate capacity. The FERC is expected to impose conditions designed to address impacts on fish and the environment. We cannot predict the specific impact of any conditions, but capital expenditures and operating costs are expected to increase in the short term and net generation from these projects will likely decrease.

Peterson Dam In January 2003, we, the Vermont Agency of Natural Resources ("Agency"), Vermont Natural Resources Council and other parties reached an agreement to allow us to relicense the four dams we own and operate on the Lamoille River. According to the agreement, we will receive a water quality certificate from the State, which is needed for FERC to relicense the facilities for 30 years. The agreement also stipulates that subject to various conditions, we must begin decommissioning Peterson Dam in about 20 years. The agreement requires PSB approval of full rate recovery related to decommissioning the Peterson Dam, including recovery of replacement power costs when the dam is out of service. In July 2003, the Agency published its draft water quality certificate and in October 2003, pursuant to the schedule set forth in the agreement, we filed a petition with the PSB for approval of the rate recovery mechanisms. In April 2004, the PSB issued an order adopting a schedule intended to permit a final order in the fourth quarter of 2004. In the second quarter of 2004, at a public hearing, many residents of the Town of Milton opposed the dam's removal. The PSB held two additional public meetings in September 2004, and testimony was given in support of and opposition to removal of the power station. The case has continued to progress through the regulatory process, with some delay, and final technical hearings are now scheduled for March and April 2005. A final order is now expected in 2005. We cannot predict the outcome of this matter.

Nuclear Generating Companies We are one of several sponsor companies with ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic, and are responsible for paying our ownership percentage of decommissioning and all other costs for each plant. We also have a 1.7303 percent joint-ownership interest in Millstone Unit #3. Our obligations related to that plant are described in more detail in Note 13 – Commitments and Contingencies.

The Maine Yankee, Connecticut Yankee and Yankee Atomic nuclear plants have been shut down and are undergoing decommissioning. Information related to decommissioning and closure costs, including our share of estimated future payments for each plant, are as follows (dollars in millions):

	Date of Study	Total Expenditures (a)	Remaining Obligation (b)	Revenue Requirements (c)	Company Share (d)
Maine Yankee	2003	$485.4	$173.0	$292.1	$5.8
Connecticut Yankee	2003	$639.5	$362.6	$630.0	$12.6
Yankee Atomic	2003	$479.7	$160.9	$119.3	$4.2

(a) Total cumulative decommissioning expenditures incurred through 2004, net of proceeds received from various legal matters settled prior to December 31, 2004.

(b) Estimated remaining decommissioning costs in 2004 dollars for the period 2005 through 2023 for Maine Yankee and Connecticut Yankee and through 2022 for Yankee Atomic.

(c) Estimated future payments required by Sponsor companies to recover estimated decommissioning and all other costs for 2005 and forward, in nominal dollars. For Maine Yankee and Connecticut Yankee includes collections for required contributions to spent fuel funds as described below. Yankee Atomic has already collected and paid these required contributions.

(d) Represents our share of revenue requirements based on ownership percentage in each plant.

Maine Yankee, Connecticut Yankee and Yankee Atomic are seeking recovery of fuel storage-related costs stemming from the default of the United States Department of Energy ("DOE") under the 1983 fuel disposal contracts that were mandated by the United States Congress under the High Level Waste Act. All three are parties to a lawsuit against the DOE seeking damages based on the DOE's default. The trial on determination of damages began on July 12 and ended August 31, 2004. Closing arguments were held in January 2005 and final post-trial briefs were filed in February 2005. A decision is expected by the end of 2005; however, an appeal by at least one of the parties is likely. None of the plants have included any allowance for potential recovery of these claims in their FERC-filed cost estimates.

Our share of Maine Yankee, Connecticut Yankee and Yankee Atomic estimated costs are reflected on the Consolidated Balance Sheets as regulatory assets or other deferred charges, and nuclear decommissioning liabilities (current and non-current). These amounts are adjusted when revised estimates are provided by the companies. At December 31, 2004, we had regulatory assets of about $5.8 million related to Maine Yankee and $2.1 million related to Connecticut Yankee. These estimated costs are being collected from our customers through existing retail rate tariffs. At December 31, 2004, we also had other deferred charges related to incremental dismantling costs of about $10.5 million for Connecticut Yankee and $7.2 million for Yankee Atomic. These amounts include payments of about $0.1 million to Connecticut Yankee and $3.0 million to Yankee Atomic, representing our share of the respective companies' collection of incremental costs as of December 31, 2004. These incremental dismantling costs are not being recovered through existing retail rate tariffs, and are being deferred based on an October 2003 PSB-approved Accounting Order for treatment of these incremental costs as deferred charges, to be addressed in our pending rate proceeding.

Maine Yankee, Connecticut Yankee and Yankee Atomic collect decommissioning and closure costs through wholesale FERC-approved rates charged under power agreements with several New England utilities, including us. Historically, our share of these costs has been recovered from retail customers through PSB-approved rates. Based on the regulatory process, Management believes its share of decommissioning and closure costs for each plant will continue to be recovered through the regulatory process. Although Management believes that the decommissioning and closure costs will ultimately be recovered from its customers, there is a risk that the FERC may not allow full recovery of Connecticut Yankee's incremental increased costs in wholesale rates. If FERC does not allow these costs to be recovered in wholesale rates, we anticipate that the PSB would disallow these costs for recovery in retail rates as well. See discussion below for additional information related to Maine Yankee, Connecticut Yankee and Yankee Atomic.

Maine Yankee: We have a 2 percent ownership interest in Maine Yankee. Billings from Maine Yankee amounted to about $1.3 million in 2004, $1.1 million in 2003 and $1.1 million in 2002, and are included in Purchased Power on the Consolidated Statements of Income. Accounts Payable to Maine Yankee for 2004 and 2003 were of a nominal amount.

In October 2003, Maine Yankee filed a FERC rate proceeding for collection of estimated decommissioning and long-term spent fuel storage costs. In July 2004, Maine Yankee and various other parties agreed to an Offer of Settlement resolving all issues raised by the rate case participants. On September 16, 2004, FERC approved the settlement, which provides for recovery of all of Maine Yankee's forecasted costs of providing service through a formula rate contained in its power contracts through October 31, 2008 and replenishment of the DOE Spent Fuel Obligation through collections from November 2008 through October 2010.

From January 1 through October 31, 2004, Maine Yankee's billings to sponsor companies were based on its FERC filing subject to refund. Beginning November 1, 2004, Maine Yankee's billings have been based on the FERC-approved settlement, reduced for excess collections that occurred prior to the effective date.

Connecticut Yankee: We have a 2 percent ownership interest in Connecticut Yankee. Billings from Connecticut Yankee amounted to $0.9 million for 2004, $0.9 million for 2003 and $0.9 million for 2002, and are included in Purchased Power on the Consolidated Statements of Income. Accounts Payable to Connecticut Yankee for 2004 and 2003 were of a nominal amount. Costs currently billed by Connecticut Yankee are based on its most recent FERC-filed rates, which became effective February 1, 2005, for collection through 2010, subject to refund, and pending a final order by FERC. Prior to February 1, 2005, costs were billed by Connecticut Yankee based on its FERC-approved rates that became effective September 1, 2000, for collection through 2007.

Connecticut Yankee is currently involved in litigation related to a contract dispute. Also in 2004, Connecticut Yankee filed a rate application with FERC. These matters are discussed in more detail below.

Bechtel Litigation: Connecticut Yankee is involved in a contract dispute with Bechtel Power Corporation ("Bechtel"), which resulted in termination of the decommissioning services contract between Connecticut Yankee and Bechtel. The lawsuit has been assigned to the Complex Litigation Docket and has been set for a jury trial beginning May 4, 2006. Connecticut Yankee also notified Bechtel's surety of its intention to file a claim under the performance bond.

On June 18, 2004, Bechtel filed a Pre-Judgment Remedy Application ("PJR") requesting a $93 million garnishment of the Decommissioning Trust ("Trust"), Connecticut Yankee shareholder payments to the Trust and any proceeds from the fuel disposal contract litigation pending between Connecticut Yankee and the DOE, as well as attachment of any Connecticut Yankee assets, including the Haddam Neck real property. On July 16, 2004, Connecticut Yankee filed its Objection to the PJR. On July 20, 2004, the Court allowed the Connecticut Department of Public Utility Control ("CT DPUC") to intervene in the PJR proceeding for the limited purpose of objecting to Bechtel's requested garnishment of the Trust and related payments. The Court held hearings on these matters in August and October 2004. On October 29, 2004, Bechtel and Connecticut Yankee entered into an agreement that made additional hearings unnecessary. Bechtel agreed to withdraw its request for an attachment of the Decommissioning Trust Fund and related payments, in return for potential attachment of Connecticut Yankee's real property in Connecticut with a book value of $7.9 million and the escrowing of $41.7 million the sponsors are scheduled to pay to Connecticut Yankee through June 30, 2007. This agreement is subject to approval of the Court and would not be implemented until the Court found that such assets were subject to attachment. Connecticut Yankee intends to contest the attachability of such assets. The agreement does not materially change the legal positions in this litigation. The CT DPUC did not object to the agreement.

FERC Rate Case Filing: In December 2003, Connecticut Yankee's Board of Directors endorsed an updated estimate ("2003 Estimate") of the costs for the plant's decommissioning project. This updated estimate reflects the fact that Connecticut Yankee is now directly managing the work (self-performing) to complete decommissioning of the plant following the default termination of Bechtel. The 2003 Estimate of approximately $831.3 million covers the time period 2000 – 2023 and represents an aggregate increase of approximately $395 million in 2003 dollars over the costs estimate in its 2000 FERC rate case settlement, which covered the same time period. The new cost estimate includes the cost of providing service under the formula rate contained in its FERC tariff, including decommissioning costs, as well as the replenishment of the Spent Fuel Trust Fund, which has been combined with the Decommissioning Trust Fund.

On June 10, 2004, the CT DPUC and the OCC filed a petition ("Petition") with FERC seeking a declaratory order that Connecticut Yankee can recover all decommissioning costs from its sponsor companies, but that those purchasers may not recover in their retail rates any costs that FERC might determine to be imprudently incurred. Connecticut Yankee and its sponsor companies, including the Company, have responded in opposition to the Petition, indicating that the order sought by the CT DPUC would violate the Federal Power Act and decisions of the United States Supreme Court, other federal and state courts, and FERC. The NHPUC filed an intervention notice in support of the Petition. Bechtel has filed an amicus brief and intervention notice in support of the Petition.

On July 1, 2004, Connecticut Yankee filed the 2003 Estimate with the FERC as part of its rate application ("Filing") seeking additional funding to complete the decommissioning project and for storage of spent fuel through 2023. The Filing requested that new rates become effective January 1, 2005. The Filing includes proposed increased decommissioning charges, based on the 2003 Estimate, as well as new annual charges for pension expense and costs of funding post-employment benefits other than pensions. The proposed annual decommissioning collection represents a significant increase in annual charges to the sponsor companies, including us, as compared to the existing FERC rates.

On July 6, 2004, FERC issued a notice of the Filing indicating that intervention and protest filings would be due by July 22; however, that date was extended to July 30, at the request of the CT DPUC. Four non-utility interventions have been filed at the FERC by the CT DPUC, the Connecticut Office of Consumer Counsel ("OCC"), Bechtel and the Massachusetts Attorney General. On August 30, 2004, FERC issued an order: 1) accepting for filing the new charges proposed by Connecticut Yankee; 2) suspending these revised charges until February 1, 2005; 3) establishing Administrative Law Judge hearing procedures and schedules; 4) denying the request of the CT DPUC and OCC for both an accelerated hearing schedule and for a bond or other security for potential refunds; 5) denying the declaratory ruling sought by the CT DPUC and OCC; and 6) granting motions to intervene for Bechtel and other applying parties.On September 7, 2004, a FERC administrative law judge was appointed to the case.

On February 22, 2005, the CT DPUC filed testimony with FERC. In its filed testimony, the CT DPUC argues that about $215 million to $225 million of Connecticut Yankee's requested increase is due to Connecticut Yankee's imprudence in managing the decommissioning project while Bechtel was the contractor. Therefore, the CT DPUC recommends a total disallowance of $225 million to $234 million. The current schedule provides for the hearings to start June 1, 2005. Connecticut Yankee anticipates that the process of resolving the matters in the Filing is likely to be contentious and lengthy.

Our estimated aggregate obligation related to Connecticut Yankee is about $12.6 million. We continue to believe that FERC will approve recovery of these increased costs in wholesale rates based on the nature of costs and previous rulings at other nuclear companies. Once approved by FERC, we believe it is unlikely that the PSB would not allow these FERC-approved costs to be recovered in retail rates. If FERC adopts the CT DPUC's recommendations described above, our share of the proposed disallowance would be about $4.7 million. The timing, amount and outcome of the Bechtel litigation and FERC rate case filing cannot be predicted at this time.

Yankee Atomic: We have a 3.5 percent ownership interest in Yankee Atomic. Billings from Yankee Atomic amounted to $1.9 million for 2004 and $1.1 million for 2003, and are included in Purchased Power on the Consolidated Statements of Income. Accounts Payable to Yankee Atomic for 2004 and 2003 were of a nominal amount. Billings from Yankee Atomic ended in July 2000 based on Yankee Atomic's determination that it had collected sufficient funds to complete the decommissioning effort. We are not currently collecting Yankee Atomic costs in retail rates.

In April 2003, Yankee Atomic filed with FERC, based on updated cost estimates, for new rates to collect these costs from sponsor companies. FERC approved the resumption of billings starting June 2003 for a recovery period through 2010, subject to refund. On August 6, 2003, Yankee Atomic filed a Settlement Agreement that resolved all issues raised by the parties. Beginning April 2004 and each year following, the new rates are subject to an annual adjustment based on the prior calendar year's data if the decommissioning trust fund market performance is 10 percent greater or 10 percent less than the assumptions used to calculate the schedule of decommissioning charges. As such, a reduction was applied to filed-rates beginning with April 2004 billings.

DIVERSIFICATION

Catamount Resources Corporation was formed to hold our subsidiaries that invest in unregulated businesses including Catamount and Eversant.

Catamount

As of December 31, 2004, Catamount has interests in six operating independent power projects located in Rumford, Maine; East Ryegate, Vermont; Hopewell, Virginia; Nolan County, Texas; Thuringen, Germany and Mecklenburg-Vorpommern, Germany.

Catamount is wholly focused on development, ownership and asset management of wind energy projects. Wind energy is competitive with other forms of electric generation and has low production costs compared to other renewable energy sources. Environmental and energy security concerns in the United States and United Kingdom support growth in the wind sector. Depending on prices, capital and other requirements, Catamount will entertain offers for the purchase of certain of its wind electric generating assets and any of its remaining non-wind electric generating assets. Additionally, Catamount is seeking investors and partners to co-invest with Catamount in the development, ownership and acquisition of projects, which will be financed by equity and non-recourse debt. Management cannot predict the timing or outcome of potential future asset sales or whether this strategy will be successful.

Catamount has projects under development in the United States and United Kingdom. In July 2003, Catamount established Catamount Cymru Cyf., an English and Wales private limited company to develop a project located in Wales. In January 2004, Catamount Energy Limited and Catamount Cymru Cyf. issued stock to a third party Norwegian investor thereby diluting Catamount's interest to 50 percent. The issuance resulted in no gain or loss.

In 2004, Catamount entered into a joint development arrangement with Marubeni Power International, Inc. The arrangement represents an exclusive agreement for wind energy development throughout New England, New York and Pennsylvania.

In 2003, Catamount ceased "greenfield" development in Germany to focus development efforts in the United States and United Kingdom.

Catamount Results Catamount's 2004 earnings totaled $3.6 million, including $2.9 million of net income tax benefits and $1.5 million of after-tax gains associated with the sales of the Fibrothetford, Rupert and Glenns Ferry investment interests. Also included was a fee associated with Catamount's United Kingdom development effort. Catamount's 2003 earnings were $0.7 million, including a $2.3 million reduction of income tax valuation allowances associated with previously recorded equity losses resulting from asset impairment for the Fibrothetford, Rupert and Glenns Ferry investments. The 2003 reduction in income tax valuation allowances resulted in a benefit to the consolidated federal income tax provision due to management's best estimate that the Company would receive capital gains treatment on the Connecticut Valley sale. Catamount's 2002 earnings totaled $1.5 million.

Catamount, or its wholly owned subsidiaries, provide certain management, accounting and other services to certain entities in which Catamount holds an equity interest. The fees are designed to recover actual costs or are agreed upon by other equity investors in these entities. All fees are billed monthly with the exception of one that is billed annually. Additionally, all fees are payable monthly except for one in which fees are payable upon receipt of dividends from its wholly owned subsidiaries. Catamount's revenues, included in Other Income on the Consolidated Statements of Income, included billings of $0.6 million in 2004, $0.5 million in 2003 and $0.6 million in 2002. Accounts Receivable for these billings amounted to $0.6 million in 2004, of which $0.5 million has been reserved for 2004, and $0.2 million in 2003. Also included in Catamount's 2004 Accounts Receivable are fees of about $0.5 million from a windfarm under construction in which Catamount has an ownership interest.

Information regarding certain of Catamount's investments follows.

Appomattox In October 2004, the partnership's long-term lease with the steam host ended. The partnership is finalizing its business operations and in December 2004, most of the project's remaining cash was distributed to the partners. In December 2004, Catamount recorded a nominal impairment associated with its general partner interest in the partnership.

Glenns Ferry and Rupert On July 1, 2004, Catamount completed the sale of its investment interests in Glenns Ferry and Rupert to a third party. The sale resulted in an after-tax gain of about $0.6 million and an additional $0.2 million of income tax benefits associated with the sale. As described above, in the third quarter of 2003, Catamount recorded a $0.6 million benefit related to the reduction of income tax valuation allowances associated with its investments in Glenns Ferry and Rupert.

Sweetwater 1 In December 2003, Catamount acquired an equity interest of $6.2 million in Sweetwater Wind 1 LLC, a 37.5-MW wind farm in Nolan County, Texas. Sweetwater Wind 1 LLC commenced commercial operations on December 23, 2003.

Sweetwater 2 In February 2005, Catamount acquired an equity interest of $15.4 million in Sweetwater Wind 2 LLC, a 91.5-MW wind farm in Nolan County, Texas. Sweetwater Wind 2 LLC commenced commercial operations on February 11, 2005.

Fibrothetford Limited In September 2004, Catamount entered into separate Sales and Purchase Agreements with a third party for the sale of its Fibrothetford note receivable and its equity investment. The note receivable was sold in September 2004, resulting in an after-tax gain of $0.6 million. Its equity investment was sold in October 2004, resulting in an after-tax gain of about $0.3 million. Both the sale of the note receivable and equity investment resulted in additional income tax benefits of $0.2 million and $2.5 million, respectively. As described above, in the third quarter of 2003, Catamount recorded a $1.7 million benefit related to the reduction of income tax valuation allowances associated with its investments in Fibrothetford.

In December 2002, Catamount had a Sale and Purchase Agreement with a third party for the sale of its Fibrothetford investment interests. In July 2003, the buyer suspended the sale and in December 2003, Catamount terminated that Sale and Purchase Agreement.

To the extent required, continuing equity losses were applied as a reduction to Catamount's note receivable balance from Fibrothetford. In 2004 and 2003, Catamount reserved approximately $1.7 million and $2 million, respectively, against interest income on the note receivable.

DK Burgerwindpark Eckolstadt and DK Windpark Kavelstorf GmbH&Co. KG (collectively "Eurowind") In December 2004, Catamount recorded an after-tax impairment of $0.2 million related to its Eurowind investments. The impairment reflects Management's best estimate of the current market value of these investments.

Heartlands Power Limited ("Heartlands") In the third quarter of 2002 Catamount recorded an after-tax investment impairment charge to earnings of $1.3 million related to the pending sale of its equity investments in Heartlands. On October 30, 2002, Catamount sold its 50 percent interest in Heartlands. The proceeds from the sales approximated the net book value of its investment.

Gauley River Catamount entered into a Purchase and Sale Agreement, dated June 30, 2002, with a third party, for sale of its Gauley River investment interests. In the third quarter of 2002, Catamount recorded a $0.8 million after-tax impairment charge to earnings based on funding certain escrow accounts as a condition of the Purchase and Sale Agreement. The sale was consummated on December 5, 2002 and the proceeds from the sale approximated net book value of its Gauley River investment interests.

Eversant

As of December 31, 2004, Eversant had a $1.4 million equity investment, representing a 12 percent ownership interest in The Home Service Store Inc. ("HSS"). HSS has established a network of affiliate contractors who perform home maintenance repair and improvements for its members. Eversant accounts for this investment on the cost basis.

Eversant's wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. ("SEWHS"), engages in the sale or rental of electric water heaters in Vermont and New Hampshire. SEWHS had earnings of $0.4 million in 2004, $0.5 million in 2003 and $0.3 million in 2002.

Overall, Eversant's earnings were $0.4 million in 2004 and $0.5 million in 2003, versus a net loss of $0.5 million in 2002. In early 2002, we discontinued Eversant's efforts to pursue unregulated business opportunities except for SEWHS.

INCOME TAX MATTERS

We account for income taxes in accordance with SFAS No. 109, which requires recognition of deferred tax assets and liabilities for the future tax effects of temporary differences between carrying amounts and the tax basis of assets and liabilities. Under this method, deferred income taxes result from applying the statutory rates to the differences between the book and tax basis of asset and liabilities.

Valuation Allowances SFAS No. 109 prohibits the recognition of all or a portion of deferred income tax benefits if it is more likely than not that the deferred tax asset will not be realized. For the periods ended 2004 and 2003, the valuation allowances recorded were $0.9 million and $0.8 million respectively for certain losses related to Catamount's foreign investments. Management added $0.1 million to the valuation allowances for certain foreign losses incurred in 2004 related to Catamount's foreign investments after it determined that it is more likely than not that a current or future income tax benefit would not be realized.

For 2003, the valuation allowances were decreased by $3.4 million. Management determined that the Connecticut Valley sale agreement was more likely than not to occur, which afforded the Company the opportunity to realize capital gains on the sale. The capital gains treatment allowed for a $2.3 million reduction of certain tax valuation allowances at Catamount. The valuation allowances were also reduced by $1.9 million due to the reclassification of an equity method of accounting adjustment related to the financial statements from one of Catamount's foreign projects. The valuation allowances were increased by $0.8 million for certain foreign losses related to Catamount's foreign investments. Management determined that it was more likely than not that a current or future income tax benefit would not be realized.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 1 to the accompanying Consolidated Financial Statements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We consider our most significant risks to be 1) regulatory risk as it relates to timely and full recovery of costs to serve our customers, and 2) wholesale power market risks given that we rely on two long-term contracts that support about 75 percent of our load requirements. Due to cost-based-rate regulation, the Vermont utility business has limited exposure to market volatility in interest rates. For a discussion of regulatory risk and the risks associated with our unregulated business, Catamount, see Vermont Retail Rates and Business Risk. Below is a discussion of the primary market-related risks associated with our core business.

Wholesale Power Market Risk Our most significant power supply contracts are with Hydro-Quebec and Vermont Yankee Nuclear Power Corporation. Combined, these contracts amounted to about 84 percent of our total energy (mWh) purchases in 2004. The contracts are described in more detail in Power Supply Matters above.

Summarized information regarding these contracts follows.

		2004		2003	
	Expires	mWh	$/mWh	mWh	$/mWh
Hydro-Quebec (a)	2016	**790,017**	**$72.08**	826,104	$69.63
VYNPC (b)	2012	**1,343,629**	**$43.69**	1,547,771	$42.37

(a) Under the terms of the Hydro-Quebec contract, there is a defined energy rate that escalates at general inflation based on the U.S. Gross National Product Implicit Price Deflator ("GNPIPD") and capacity rates are constant with the potential for small reductions if interest rates decrease below average values set in prior years.
(b) Under the terms of the contract with VYNPC the energy price generally ranges from 3.9 cents to 4.5 cents per kilowatt-hour through 2012. Effective November 2005, the contract prices are subject to a "low-market adjuster" mechanism as described in Power Supply Matters.

We have other power contracts that we account for under the guidance of SFAS No. 133. Summarized information related to unrealized gains and losses on energy-related derivatives is shown in the table below (in thousands):

	Unrealized Gain	Unrealized Loss
Contracts beginning of year	$444	$1,296
Contracts realized or settled	(444)	(71)
New contract	385	-
Changes in fair value	-	4,510
Contracts at year end	$385	$5,735
Source	Over-the-counter quotations	Quoted market data & valuation methodologies

Changes in fair value of these derivatives are recorded as deferred charges or deferred credits on the Consolidated Balance Sheets depending on whether the fair value is an unrealized loss or gain, with an offsetting amount recorded as a decrease or increase in the related derivative asset or liability. See Critical Accounting Policies and Estimates for a discussion of derivative financial instruments.

Pension Interest rate changes could also impact calculations related to estimated pension and other benefit liabilities, affecting pension and other benefit expenses and potentially requiring contributions to the trusts. See Critical Accounting Policies and Estimates, and Note 10 to the Consolidated Financial Statements for additional information related to Pension and Postretirement Benefits.

Equity Market Risk As of December 31, 2004, our pension trust held marketable equity securities in the amount of $44.3 million and our Millstone Unit #3 decommissioning trust held marketable equity securities of $3.5 million. We also maintain a variety of insurance policies in a Rabbi Trust with a current value of $6 million to support various supplemental retirement and deferred compensation plans. The current values of certain policies are affected by changes in the equity market.

Credit Risk We have $16.9 million of letters of credit expiring on November 30, 2005. These letters of credit support three series of Industrial Development Revenue Bonds, totaling $16.3 million.

Based on outstanding debt at December 31, 2004, no payments are due on long-term debt for 2005 through 2007. The 8.3 percent Dividend Series Preferred Stock is redeemable at par through a mandatory sinking fund of $1 million annually. In the fourth quarters of 2004 and 2003, we recorded $2 million in Restricted Cash related to December 2004 and December 2003 payments to the Transfer Agent for the annual $1 million mandatory sinking fund payments and a $1 million optional payment for each year. The payments to the Preferred Shareholders were made effective January 1, 2005 and January 1, 2004.

The covenants covering our First Mortgage Bonds contain limiting restrictions if those bonds receive a debt rating below BBB- from rating agencies. The current ratings of the bonds are BBB+ (stable) from Standard & Poor's and BBB+ (stable) from Fitch. The limiting characteristics include, but are not limited to, certain restrictions on investments in unregulated subsidiaries, the incurrence of indebtedness and the payment of dividends. These restrictions are dependent on meeting both a Fixed Charge Coverage and a Cumulative Cash Flow test, and we are currently in compliance with both calculations.

Interest Rate Risk As of December 31, 2004, we had $16.3 million of Industrial Development Revenue bonds outstanding, of which $10.8 million have an interest rate that floats monthly with the short-term credit markets and $5.5 million that floats every five years with comparable credit markets. All other utility debt has a fixed rate. There are no interest lock or swap agreements in place.

The table below provides information about interest rates on our long-term debt and Industrial Development Revenue bonds.

	Expected Maturity Date						
Liabilities	**2005**	2006	2007	2008	2009	Thereafter	Total
Long-Term Debt:							
Fixed Rate ($)	**$7.1**	$7.1	$7.1	$7.1	$6.9	$77.3	$112.6
Average Fixed Interest Rate (%)	**6.39%**	6.39%	6.39%	6.38%	6.39%	7.17%	
Variable Rate ($)	**$0.2**	$0.2	$0.2	$0.2	$0.2	$1.0	$2.0
Average Variable Rate (%)	**1.85%**	1.85%	1.85%	1.85%	1.85%	1.86%	

We also have temporary cash investments and available-for-sale securities that are subject to interest rate volatility. These are described in more detail in Note 8 - Financial Instruments and Investment Securities.

Selected Financial Data

(in thousands, except per share amounts)	2004	2003	2002	2001	2000
Operating revenues	**$302,200**	$306,014	$294,390	$292,900	$333,926
Income from continuing operations	**$11,415**	$18,355	$18,224	$754	$18,043
Income from discontinued operations	**$12,340**	$1,446	$1,543	$1,653	-
Net income	**$23,755**	$19,801	$19,767	$2,407	$18,043
Earnings available for common stock	**$23,387**	$18,603	$18,239	$711	$16,264
Consolidated return on average common stock equity	**10.7%**	9.2%	9.6%	0.4%	8.6%
Common Stock Data					
Basic:					
Earnings (loss) per share from continuing operations	**$.91**	$1.45	$1.43	$(.08)	$1.42
Earnings from discontinued operations	**$1.02**	$.12	$.13	$.14	-
Earnings per share	**$1.93**	$1.57	$1.56	$.06	$1.42
Diluted:					
Earnings (loss) per share from continuing operations	**$.90**	$1.41	$1.40	$(.08)	$1.41
Earnings from discontinued operations	**$1.00**	.12	.13	.14	-
Earnings per share	**$1.90**	$1.53	$1.53	$.06	$1.41
Cash dividends paid per share of common stock	**$.92**	$.88	$.88	$.88	$.88
Book value per share of common stock	**$18.49**	$17.57	$16.83	$15.81	$16.57
Net cash provided by operating activities of continuing operations	**$25,589**	$46,577	$42,446	$30,216	$60,867
Dividends paid	**$12,174**	$11,640	$12,222	$11,433	$11,888
Construction and plant expenditures	**$20,174**	$14,959	$13,885	$16,148	$14,968
Conservation and load management expenditures	**$91**	$104	$236	$504	$1,136
At End of Year					
Long-term debt (1)	**$126,750**	$126,750	$137,908	$159,771	$152,975
Capital lease obligations (1)	**$7,094**	$8,115	$11,762	$12,897	$13,978
Redeemable preferred stock (1)	**$6,000**	$8,000	$10,000	$15,000	$16,000
Total capitalization	**$373,361**	$362,170	$365,332	$379,236	$381,704
Total assets	**$546,763**	$528,664	$540,849	$531,164	$539,838

(1) Excluding current portion

The management of Central Vermont Public Service Corporation is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934. The Company's internal control over financial reporting is a process designed under the supervision of the Company's principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and of the preparation and fair presentation of the Company's financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America.

As of December 31, 2004, management assessed the effectiveness of the Company's internal control over financial reporting based on the framework established in "Internal Control-Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management did not identify any material weakness in the Company's internal control over financial reporting, and has concluded that the Company's internal control over financial reporting was effective as of December 31, 2004.

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.

Deloitte & Touche LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this annual report, has issued an attestation report on management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. The report, which expresses unqualified opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, is included on page 23 of this Annual Report under the heading "Report of Independent Registered Public Accounting Firm."

Robert H. Young
President and
Chief Executive Officer

Jean Gibson
Senior Vice President, Chief
Financial Officer and Treasurer

To the Board of Directors and Stockholders of Central Vermont Public Service Corporation:

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

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2004 of the Company and our report dated March 7, 2005 expressed an unqualified opinion on those financial statements and includes an explanatory paragraph regarding the sale by the Company's wholly owned subsidiary, Connecticut Valley Electric Company, of substantially all of its plant assets and its franchise to Public Service Company of New Hampshire on January 1, 2004.

Deloitte & Touche LLP

Deloitte & Touche, LLP
Boston, Massachusetts
March 14, 2005

To the Board of Directors and Stockholders of Central Vermont Public Service Corporation:

We have audited the accompanying consolidated balance sheets of Central Vermont Public Service Corporation and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of income, comprehensive income, changes in common stock equity and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Central Vermont Public Service 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.

As discussed in Note 4 to the consolidated financial statements, Connecticut Valley Electric Company, a wholly owned subsidiary of the Company, completed the sale of substantially all of its plant assets and its franchise to Public Service Company of New Hampshire on January 1, 2004. The gain on sale and results of Connecticut Valley Electric Company's operations prior to the sale are included in income from discontinued operations in the accompanying consolidated financial statements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 7, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Deloitte & Touche, LLP
Boston, Massachusetts
March 14, 2005

(in thousands, except per share amounts)	Years Ended December 31 2004	2003	2002
Operating Revenues	**$302,200**	$306,014	$294,390
Operating Expenses			
Operation			
Purchased power	**165,651**	152,994	142,430
Production and transmission	**25,389**	26,031	25,490
Other operation	**50,729**	46,732	43,454
Maintenance	**16,835**	16,816	17,477
Depreciation	**16,045**	15,930	16,467
Other taxes, principally property taxes	**13,616**	13,367	12,860
Taxes on income	**1,056**	10,125	11,009
Total operating expenses	**289,321**	281,995	269,187
Operating Income	**12,879**	24,019	25,203
Other Income and Deductions			
Equity in earnings of affiliates	**1,225**	1,801	3,909
Equity in earnings of non-utility investments	**4,220**	6,362	11,650
Gain on sale of non-utility investments	**2,518**	-	-
Allowance for equity funds during construction	**149**	87	71
Other income	**8,845**	7,211	6,814
Other deductions	**(9,255)**	(10,855)	(16,882)
Benefit (provision) for income taxes	**693**	1,470	(82)
Total other income and deductions	**8,395**	6,076	5,480
Total Operating and Other Income	**21,274**	30,095	30,683
Interest Expense			
Interest on long-term debt	**8,925**	11,231	12,526
Other interest	**991**	547	(32)
Allowance for borrowed funds during construction	**(57)**	(38)	(35)
Total interest expense	**9,859**	11,740	12,459
Income from continuing operations	**11,415**	18,355	18,224
Income from discontinued operations, net of tax (including gain on disposal of $12,354 in 2004)	**12,340**	1,446	1,543
Net Income	**23,755**	19,801	19,767
Dividends on preferred stock	**368**	1,198	1,528
Earnings Available for Common Stock	**$23,387**	$18,603	$18,239
Per Common Share Data:			
Basic			
Earnings from continuing operations	**$0.91**	$1.45	$1.43
Earnings from discontinued operations	**1.02**	.12	.13
Earnings per share	**$1.93**	$1.57	$1.56
Diluted			
Earnings from continuing operations	**$0.90**	$1.41	$1.40
Earnings from discontinued operations	**1.00**	.12	.13
Earnings per share	**$1.90**	$1.53	$1.53
Average shares of common stock outstanding – basic	**12,118,048**	11,878,255	11,660,369
Average shares of common stock outstanding – diluted	**12,301,187**	12,126,993	11,942,822
Dividends paid per share of common stock	**$.92**	$.88	$.88

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

(in thousands)	2004	2003	2002
		Years Ended December 31	
Net Income	**$23,755**	$19,801	$19,767
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments	**(445)**	456	800
Unrealized loss on investments	**(228)**	(44)	-
Non-qualified benefit obligations	**58**	(77)	(27)
	(615)	335	773
Comprehensive income	**$23,140**	$20,136	$20,540

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

(in thousands)	2004	2003	2002
		Years Ended December 31	
Cash Flows Provided (Used) By:			
Operating Activities			
Net Income	**$23,755**	$19,801	$19,767
Deduct: Income from discontinued operations - net of income taxes	**(12,340)**	(1,446)	(1,543)
Income from continuing operations	**11,415**	18,355	18,224
Adjustments to reconcile net income to net cash provided by operating activities			
Equity in earnings of affiliates	**(1,225)**	(1,801)	(3,909)
Dividends received from affiliates	**1,229**	2,441	4,040
Equity in earnings from non-utility investments	**(4,220)**	(6,362)	(11,603)
Distribution of earnings from non-utility investments	**10,952**	12,915	10,639
Depreciation	**16,045**	15,930	16,467
Gain on sale of non-utility investments	**(2,518)**	-	-
Vermont Utility mandated earnings cap	**3,823**	2,475	681
Asset impairment charges, including tax valuation allowance	**258**	142	2,774
Amortization of capital leases	**1,021**	1,020	1,019
Deferred income taxes and investment tax credits	**(3,457)**	(2,657)	3,058
Reversal of deferred income tax valuation allowance	**-**	(2,293)	-
Net (deferral) amortization of nuclear replacement energy and maintenance costs	**(538)**	653	3,683
Amortization of conservation and load management costs	**207**	1,461	2,217
Reserve for loss on power contract (SFAS No. 5 loss accrual)	**14,351**	-	-
Amortization of SFAS No. 5 loss accrual	**(1,196)**	-	-
Vermont Yankee replacement energy deferral	**(834)**	-	-
Decrease in accounts receivable and unbilled revenues	**(1,791)**	874	561
(Decrease) increase in accounts payable	**(168)**	(440)	61
(Decrease) increase in accrued income taxes	**(9,286)**	(755)	877
(Increase) decrease in other current assets	**(2,508)**	(4,538)	2,919
Increase in notes receivable - non-utility affiliates	**(6,523)**	-	-
Increase (decrease) in other current liabilities	**1,744**	1,338	1,945
Unrealized (gain) loss on investments	**228**	-	-
Increase in pension and benefit obligations	**3,069**	3,154	768
Change in environmental reserve	**-**	(1,088)	(1,844)
Deferred Vermont Yankee fuel rod costs	**(300)**	982	(3,854)
Deferred Vermont Yankee sale costs	**(563)**	-	(8,197)
(Increase) decrease in other long-term assets	**(2,295)**	3,120	3,077
Increase (decrease) in other long-term liabilities and other	**(1,331)**	1,651	(1,157)
Net cash provided by operating activities of continuing operations	**25,589**	46,577	42,446
Investing Activities			
Construction and plant expenditures	**(20,174)**	(14,959)	(13,885)
Conservation and load management expenditures	**(91)**	(104)	(236)
Return of capital	**220**	14,040	336
Proceeds from sale of non-utility assets	**5,106**	-	13,335
Non-utility investments	**(23,112)**	(6,377)	(253)
Utility investments	**(7,008)**	(177)	(449)
Investments in available-for-sale securities	**(343,749)**	(171,249)	(108,374)
Proceeds from sale of available-for-sale securities	**336,645**	143,974	106,174
Other investments	**83**	(290)	(258)
Net cash used for investing activities of continuing operations	**(52,080)**	**(35,142)**	**(3,610)**
Financing Activities			
Proceeds from exercise of stock options	**670**	2,348	416
Proceeds from dividend reinvestment program	**1,923**	1,794	1,309
Retirement of preferred stock	**(2,000)**	-	(6,000)
Retirement of long-term debt	**(77,660)**	(29,381)	(8,208)
Decrease (increase) in restricted cash	**-**	10,560	(12,560)
Proceeds from issuance of long-term debt	**75,000**	-	-
Debt issuance costs & other	**(442)**	-	-
Common and preferred dividends paid	**(12,174)**	(11,640)	(12,222)
Reduction in capital lease obligations	**(1,021)**	(1,020)	(1,019)
Net cash used for financing activities of continued operations	**(15,704)**	(27,339)	(38,284)
Effect of exchange rate changes on cash	**(19)**	(497)	118
Cash flows provided by (used for) discontinued operations	**30,164**	(531)	(557)
Net Increase (Decrease) In Cash and Cash Equivalents	**(12,050)**	(16,932)	113
Cash and Cash Equivalents at Beginning of Year	**23,772**	40,704	40,591
Cash and Cash Equivalents at End of Year	**$11,722**	$23,772	$40,704

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

(in thousands)	Years Ended December 31 2004	2003
ASSETS		
Utility Plant, at original cost	**$502,551**	$492,507
Less accumulated depreciation	**213,719**	207,474
Net utility plant	**288,832**	285,033
Construction work-in-progress	**9,657**	9,988
Nuclear fuel, net	**971**	1,016
Total utility plant	**299,460**	296,037
Investments and Other Assets		
Investments in affiliates	**16,070**	9,303
Non-utility investments	**25,670**	34,765
Non-utility property, less accumulated depreciation	**2,936**	2,236
Millstone decommissioning trust fund	**4,721**	4,340
Available-for-sale securities	**21,918**	-
Other	**6,145**	5,249
Total investments and other assets	**77,460**	55,893
Current Assets		
Cash and cash equivalents	**11,722**	23,772
Available-for-sale securities	**19,262**	34,375
Restricted cash	**2,000**	2,000
Notes receivable	**29,182**	3,750
Accounts receivable, less allowance for uncollectible accounts ($1,886 in 2004 and $1,625 in 2003)	**20,832**	19,729
Accounts receivable – affiliates, less allowance for uncollectible accounts ($484 in 2004 and $0 in 2003)	**909**	2,171
Unbilled revenues	**17,693**	17,505
Materials and supplies, at average cost	**3,435**	3,699
Prepayments	**6,326**	3,226
Other current assets	**2,213**	2,522
Assets held for sale	**-**	9,292
Total current assets	**113,574**	122,041
Deferred Charges and Other Assets		
Regulatory Assets	**13,141**	17,555
Other deferred charges – regulatory	**36,945**	30,929
Other	**6,183**	6,209
Total deferred charges and other assets	**56,269**	54,693
Total Assets	**$546,763**	$528,664

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

(in thousands)	Years Ended December 31 2004	2003
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock, $6 par value, authorized 19,000,000 shares (issued 12,193,093 and 12,020,738)	**$73,153**	$72,119
Other paid-in capital	**51,964**	51,334
Accumulated other comprehensive income	**(130)**	485
Deferred compensation – employee stockownership plans	**(36)**	(969)
Retained earnings	**100,512**	88,282
Total common stock equity	**225,463**	211,251
Preferred and preference stock	**8,054**	8,054
Preferred stock with sinking fund requirements	**6,000**	8,000
Long-term debt	**126,750**	126,750
Capital lease obligations	**7,094**	8,115
Total capitalization	**373,361**	362,170
Current Liabilities		
Current portion of preferred stock	**2,000**	2,000
Current portion of long-term debt	**-**	2,657
Accounts payable	**6,478**	6,650
Accounts payable – affiliates	**10,764**	10,985
Accrued income taxes	**573**	196
Accrued interest	**323**	2,801
Nuclear decommissioning costs	**5,436**	4,026
Other current liabilities	**20,331**	18,620
Liabilities of assets held for sale	**-**	5,499
Total current liabilities	**45,905**	53,434
Deferred Credits and Other Liabilities		
Deferred income taxes	**32,379**	36,713
Deferred investment tax credits	**4,478**	4,880
Nuclear decommissioning costs	**17,183**	22,934
Asset retirement obligations	**3,643**	3,449
Accrued pension and benefit obligations	**23,508**	20,439
Other	**46,306**	24,645
Total deferred credits and other liabilities	**127,497**	113,060
Commitments and Contingencies		
Total Capitalization and Liabilities	**$546,763**	$528,664

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

Consolidated Statements of Changes in Common Stock Equity

(dollars in thousands)	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Deferred Compensation Plan – Employee Stock Plans	Accumulated Other Comprehensive Income	Treasury Stock	Retained Earnings	Total
Balance, December 31, 2001	11,610,683	$70,715	$47,634	$(1,097)	$(623)	$(2,285)	$69,170	$183,514
Common stock issuance:								
Treasury stock (at cost) for stock compensation plans	56,754					720	165	885
Treasury stock (at cost) for dividend reinvestment plan	53,557					708	219	927
Dividend reinvestment plan	21,647	130						130
Allocation of benefits - performance and restricted plans			408	(1,016)				(608)
Amortization of benefits - performance plans				1,010				1,010
Amortization of benefits - restricted plan			72	62				134
Net income							19,767	19,767
Other comprehensive income net of taxes					773			773
Cash dividends on capital stock:								
Common - $.88 per share							(7,716)	(7,716)
Cumulative preferred (non-redeemable)							(594)	(594)
Cumulative preferred (redeemable)							(934)	(934)
Amortization of preferred stock issuance expenses			39					39
Premium on capital stock			257					257
Other adjustments			24					24
Balance, December 31, 2002	11,742,641	$70,845	$48,434	$(1,041)	$150	$(857)	$80,077	$197,608
Common stock issuance:								
Treasury stock (at cost) for stock compensation plans	64,854					857		857
Stock compensation plans	116,210	691	1,475				44	2,210
Dividend reinvestment plan	93,283	560	1,245					1,805
Allocation of benefits - performance and restricted plans			101	(824)				(723)
Amortization of benefits - performance plans				834				834
Amortization of benefits - restricted plan	3,750	23	52	62				137
Net income							19,801	19,801
Other comprehensive income net of taxes					335			335
Cash dividends on capital stock:								
Common - $.88 per share							(10,442)	(10,442)
Cumulative preferred (non-redeemable)							(368)	(368)
Cumulative preferred (redeemable)							(830)	(830)
Amortization of preferred stock issuance expenses			27					27
Other adjustments								
Balance, December 31, 2003	12,020,738	$72,119	$51,334	$(969)	$485	$-	$88,282	$211,251
Common stock issuance:								
Stock compensation plans	76,979	462	1,093					1,555
Dividend reinvestment plan	90,863	545	1,367					1,912
Allocation of benefits - performance and restricted plans			(1,927)	728				(1,199)
Amortization of benefits - performance plans				165				165
Amortization of benefits - restricted plan	4,513	27	68	40				135
Net income							23,755	23,755
Other comprehensive income net of taxes					(615)			(615)
Cash dividends on capital stock								
Common - $0.92 per share							(11,142)	(11,142)
Cumulative preferred (non-redeemable)							(368)	(368)
Amortization of preferred stock issuance expenses			20					20
Other adjustments			9				(15)	(6)
Balance, December 31, 2004	**12,193,093**	**$73,153**	**$51,964**	**$(36)**	**$(130)**	**$ -**	**$100,512**	**$225,463**

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

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

About Central Vermont Public Service Corporation Central Vermont Public Service Corporation (the "Company") is a Vermont-based electric utility that transmits, distributes and sells electricity, and invests in renewable and independent power projects. The Company's wholly owned subsidiaries include: Catamount Energy Corporation ("Catamount"), which invests primarily in wind energy projects in the United States and the United Kingdom; Eversant Corporation ("Eversant"), which operates a rental water heater business through its subsidiary, SmartEnergy Water Heating Services, Inc.; and Connecticut Valley Electric Company Inc. ("Connecticut Valley"), which distributed and sold electricity in parts of New Hampshire. On January 1, 2004, Connecticut Valley completed the sale of substantially all of its plant assets and franchise. See Note 4 - Discontinued Operations.

Consolidation Policy and Use of Estimates The consolidated financial statements include the accounts of the Company and its subsidiaries in which it has a controlling interest. Inter-company transactions have been eliminated in consolidation.

Investments in entities over which the Company does not maintain a controlling financial interest are accounted for using the equity method when the Company has the ability to exercise significant influence over their operations. Under this method, the Company records its ownership share of the net income or loss of each investment in the accompanying consolidated financial statements. Additionally, the Company has concluded that consolidation of these investments is not required under the provisions of FASB Interpretation No. 46, *Consolidation of Variable Interest Entities,* as revised ("FIN 46R").

The Company's interests in jointly owned generating and transmission facilities are accounted for on a pro-rata basis using the Company's ownership percentages and are recorded in the Company's Consolidated Balance Sheets. The Company's share of operating expenses for these facilities is included in the corresponding operating accounts on the Consolidated Statements of Income.

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP") requires Management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities, and revenues and expenses. Actual results could differ from those estimates.

Utility Regulation The Company is regulated by the Vermont Public Service Board ("PSB"), the Connecticut Department of Public Utility and Control and the Federal Energy Regulatory Commission ("FERC"), with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. The Company prepares its financial statements in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"), for its regulated Vermont service territory and FERC-regulated wholesale business. In order for a company to report under SFAS No. 71, the company's rates must be designed to recover its costs of providing service, and the company must be able to collect those rates from customers. If rate recovery of these costs becomes unlikely or uncertain, whether due to competition or regulatory action, this accounting standard would no longer apply to the Company's regulated operations. In the event the Company determines that it no longer meets the criteria for applying SFAS No. 71, the accounting impact would be an extraordinary non-cash charge to operations of an amount that would be material unless stranded cost recovery is allowed through a rate mechanism. Criteria that could give rise to the discontinuance of SFAS No. 71 include: 1) increasing competition that restricts the company's ability to establish prices to recover specific costs, and 2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. Management periodically reviews these criteria to ensure the continuing application of SFAS No. 71 is appropriate. Based on a current evaluation of the factors and conditions expected to impact future cost recovery, Management believes future recovery of its regulatory assets in the State of Vermont for its retail and wholesale businesses is probable.

Discontinued Operations The assets and liabilities of Connecticut Valley are classified as held for sale in the Consolidated Balance Sheets in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* ("SFAS No. 144"). The results of operations related to Connecticut Valley are reported as discontinued operations for all periods presented, and certain of the Company's common corporate costs, which were previously allocated to Connecticut Valley, were reallocated back to continuing operations to reflect the sale's impact on continuing operations. The Company began to present Connecticut Valley as discontinued operations in the second quarter of 2003 based on the New Hampshire Public Utility Commission's ("NHPUC") approval of the sale of Connecticut Valley's plant assets and franchise to Public Service Company of New Hampshire ("PSNH"). The sale to PSNH was completed on January 1, 2004. See Note 4 – Discontinued Operations.

Unregulated Business Results of operations of Catamount and Eversant are included in the Other Income and Deductions section of the Consolidated Statements of Income. Catamount's policy is to expense all screening, feasibility and development expenditures associated with determining viability of investments in new projects. Catamount's project costs incurred subsequent to obtaining financial viability are recognized as assets subject to depreciation or amortization. Project viability is obtained when it becomes probable that costs incurred will generate future economic benefits sufficient to recover these costs. See Note 3 – Non-Utility Investments.

Revenues Revenues that are related to the sale of electricity are generally recorded when service is rendered or electricity is distributed to customers. Electricity sales to customers are based on monthly meter readings. Estimated unbilled revenues are recorded at the end of each monthly accounting period. In order to determine unbilled revenues, the Company makes various estimates including: 1) energy generated, purchased and resold; 2) losses of energy over transmission and distribution lines; 3) kilowatt-hour usage by retail customer mix — residential, commercial and industrial; and 4) average retail customer pricing rates. Unbilled revenues at year end were \$17.7 million in 2004 and \$17.5 million in 2003.

The Company records contractual or firm wholesale sales in the month that power is delivered; these resale sales are based on long-term and short-term contracts with parties in New England. The Company also engages in short-term hourly sales in the wholesale markets administered by the New England Independent System Operator ("ISO-New England"). Such sales are transacted with ISO-New England through the normal settlement process. On a monthly basis, the Company aggregates the hourly sales and records them as Operating Revenue.

Purchased Power The Company records the annual cost of power obtained under long-term contracts as operating expenses. These contracts are considered executory in nature, since they do not convey to the Company the right to use the related property, plant or equipment. The Company engages in short-term purchases with other third parties, primarily in New England, and records those purchases as operating expenses in the month the power is delivered. The Company also engages in short-term hourly purchases in the wholesale markets administered by ISO-New England.

Such purchases are transacted with ISO-New England through the normal settlement process. On a monthly basis, the Company aggregates the hourly purchases, and records them as Purchased Power.

Capital Lease The Company records its commitments with respect to the Hydro-Quebec Phase I and II transmission facilities as capital leases. See Note 13 – Commitments and Contingencies.

Income Taxes In accordance with SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109"), the Company recognizes deferred tax assets and liabilities for the cumulative effect of all temporary differences between financial statement carrying amounts and the tax basis of existing assets and liabilities using the tax rate expected to be in effect when the differences are expected to reverse. Investment tax credits associated with utility plant are deferred and amortized ratably to income over the lives of the related properties. The Company records a valuation allowance for deferred tax assets if management determines that is more likely than not such tax assets will not be realized. See Note 11 – Income Taxes.

Net Utility Plant Utility plant is recorded at original cost. Replacements of retirement units of property are charged to utility plant. Maintenance and repairs, including replacements not qualifying as retirement units of property, are charged to maintenance expense. The original cost of units retired, net of salvage value, are charged to accumulated provision for depreciation. The primary components of utility plant include (in thousands):

	December 31 2004	2003
Electric – transmission and distribution	$381,825	$372,090
Jointly owned generation and transmission units	109,604	109,321
Property under capital leases	8,114	9,135
Completed construction	2,965	1,918
Held for future use	43	43
Utility plant, at original cost	502,551	492,507
Less accumulated depreciation	213,719	207,474
Net Utility Plant	$288,832	$285,033

Depreciation The Company uses the straight-line remaining life method of depreciation. The total composite depreciation rate was 3.23 percent of the cost of depreciable utility plant in 2004, 3.28 percent in 2003 and 3.34 percent in 2002.

Allowance for Funds Used During Construction Allowance for funds used during construction ("AFUDC") is a non-cash item that is included in the cost of utility plant and represents the cost of borrowed and equity funds used to finance construction. AFUDC rates used by the Company were 9.5 percent in 2004, 9.3 percent in 2003 and 9.3 percent in 2002. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of interest expense on the Consolidated Statements of Income. The cost of equity funds is recorded as other income on the Consolidated Statements of Income.

Regulatory Assets, Deferred Charges and Regulatory Liabilities Under SFAS No. 71, the Company accounts for certain transactions in accordance with permitted regulatory treatment such that regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered in future revenues. In the event that the Company no longer meets the criteria under SFAS No. 71 and there is not a rate mechanism to recover these costs, the Company would be required to write off related regulatory assets, certain other deferred charges and regulatory liabilities that are summarized in the table that follows (in thousands):

Net regulatory assets, deferred charges and regulatory liabilities

	December 31 2004	2003
Regulatory assets *		
Conservation and load management ("C&LM")	$408	$517
Nuclear refueling outage costs – Millstone	647	109
Income taxes	3,987	5,640
Maine Yankee nuclear power plant dismantling costs (a)	5,843	7,287
Connecticut Yankee nuclear power plant dismantling costs (a)	2,108	2,980
Unrecovered plant and regulatory study costs (b)	-	874
Other regulatory assets	148	148
Subtotal Regulatory assets	13,141	17,555
Other deferred charges – regulatory		
Vermont Yankee fuel rod maintenance deferral **	3,401	3,101
Vermont Yankee sale costs **	9,268	8,704
Vermont Yankee replacement energy deferral (c)	834	-
Yankee Atomic incremental dismantling costs (a)	7,162	7,481
Connecticut Yankee incremental dismantling costs (a)	10,545	10,347
Unrealized loss on power contract derivatives (d)	5,735	1,296
Subtotal Other deferred charges – regulatory	36,945	30,929
Other deferred credits – regulatory ***		
Millstone Unit #3 decommissioning	629	304
IPP Settlement Reimbursement and VEPPI cost mitigation	1,200	757
Vermont utility allowed rate of return at 11 percent (e)	7,345	3,220
Vermont Yankee NEIL Insurance refund (f)	-	461
Asset Retirement Obligation – Millstone Unit #3 (g)	1,078	891
Unrealized gain on power contract derivatives (d)	385	444
Other regulatory liabilities	518	602
Subtotal Other deferred credits – regulatory	11,155	6,679
Net regulatory assets, deferred charges and other deferred credits	$38,931	$41,805

* Regulatory assets are currently being recovered in rates and, with the exception of C&LM and Other regulatory assets, include an associated return.

** These items include a provision for carrying costs and are being addressed in the Company's rate case, per the approved PSB Accounting Orders that are associated with them.

*** Included in Other Deferred Credits as shown below.

a) Regulatory assets related to Connecticut Yankee and Maine Yankee represent estimated decommissioning costs that are being collected from the Company's customers through existing retail rate tariffs. The estimated incremental dismantling costs for these facilities and for Yankee Atomic that are not included in retail rates are recorded as deferred charges, based on an October 2003 PSB-approved Accounting Order. These deferred charges are being addressed in the Company's rate case. See Note 2 – Investments in Affiliates.

b) The Company had been recovering costs related to its past investment in Seabrook through its wholesale power contract with Connecticut Valley. The contract was terminated on January 1, 2004 as a result of the Connecticut Valley sale. The remaining regulatory asset was written off in the first quarter of 2004, which reduced the reported gain on the sale. See Note 4 – Discontinued Operations.

c) On July 12, 2004, the PSB approved the Company's request for a preliminary Accounting Order to defer incremental replacement power costs incurred as a result of an unscheduled outage at the Vermont Yankee plant. The plant was offline from June 18 through July 7, 2004, and as a result the Company incurred about $0.8 million of incremental replacement power costs. The PSB's approval included the following two provisions: 1) it did not allow for recovery of carrying costs; and 2) it required monthly amortization over a three-year period beginning July 1, 2004. On July 28, 2004, the PSB granted the Company's request to stay these two provisions, and the PSB will issue its Final Accounting Order as part of the Company's rate case. See Note 13- Commitments and Contingencies.

d) The Company records derivative contracts on the Consolidated Balance Sheets at fair value. Based on a PSB-approved Accounting Order, changes in fair value of these derivatives are recorded as deferred charges or deferred credits on the Consolidated Balance Sheets depending on whether the fair value is an unrealized loss or gain, with an offsetting amount recorded as a decrease or increase in the related derivative asset or liability. See discussion of Derivative Financial Instruments below.

e) On February 18, 2005, the PSB approved the Company's request for an Accounting Order that, among other things, allowed for deferral of 2004 Vermont utility earnings in excess of an 11 percent return on equity. In order to achieve the 11 percent return on equity, the Vermont utility's 2004 earnings were reduced by about $2.3 million after-tax. The Company deferred the related pre-tax amount as a regulatory liability in the amount of $3.8 million. Per a July 2001 PSB-approved rate order, Vermont utility earnings were capped at 11 percent through January 1, 2004. In order to achieve this mandated earnings cap, Vermont utility earnings were reduced by about $1.5 million pre-tax in 2003 and $0.4 million pre-tax in 2002. Per PSB-approval, the Company deferred the related pre-tax amounts of $2.5 million in 2003 and $0.7 million in 2002, as regulatory liabilities, including carrying costs. The Company will account for and use these regulatory liabilities as determined by the PSB in its final order on the rate case. See Note 12 - Retail Rates.

f) Pursuant to PSB approval of the Vermont Yankee sale, distributions from Nuclear Electric Insurance Limited ("NEIL") received by Vermont Yankee and passed to the Company and one other sponsor company must benefit ratepayers through programs to promote renewable resources. On April 7, 2004, the PSB approved the Company's plan for use of these funds, which included a $0.2 million grant to the Vermont Small Wind Solar Fund, and the remaining balance for creation of a Renewable Development Trust Fund. In December 2004, these funds were transferred to the Vermont Community Loan Fund.

g) See discussion of asset retirement obligations below.

Other Current Liabilities The Company's miscellaneous current liabilities include the following (in thousands):

	December 31	
	2004	2003
Accrued employee costs - payroll and medical	**$4,277**	$3,373
Other taxes and Energy Efficiency Utility	**2,800**	3,254
Deferred compensation plans	**2,689**	2,749
Customer deposits, prepayments and interest	**1,753**	2,021
Obligation under capital leases	**1,020**	1,020
Environmental and accident reserves	**1,503**	1,755
Accrued joint-owned expenses	**276**	302
Reserve for loss on power contract	**1,196**	-
Miscellaneous accruals	**4,817**	4,146
Total	**$20,331**	$18,620

Other Deferred Credits The Company's other deferred credits and other liabilities include the following (in thousands):

	December 31	
	2004	2003
Environmental reserve	**$5,045**	$5,983
Non-legal asset retirement obligation	**6,743**	5,226
Other deferred credits - regulatory	**11,155**	6,679
Deferred tax liabilities	**4,530**	4,451
Reserve for loss on power contract	**11,959**	-
Power contract derivatives	**5,735**	1,296
Other	**1,139**	1,010
Total	**$46,306**	$24,645

Valuation of Long-Lived Assets The Company periodically evaluates the carrying value of long-lived assets and long-lived assets to be disposed of, including its investments in nuclear generating companies, its unregulated investments, and its interests in jointly owned generating facilities, when events and circumstances warrant such a review. The carrying value of such assets is considered impaired when the anticipated undiscounted cash flow from such an asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the long-lived asset. See Note 3 – Non-Utility Investments for discussion of impairment of non-utility investments.

Asset Retirement Obligations SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143") provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of long-lived assets. It also requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. The Company adopted SFAS No. 143 on January 1, 2003 as required and it did not have a cumulative effect on earnings upon adoption.

Legal Asset Retirement Obligations The Company has legal retirement obligations associated with decommissioning related to its investments in nuclear plants. Changes to asset retirement obligations are as follows (in millions):

	2004	2003
Asset retirement obligations at January 1	**$3.4**	-
Asset retirement obligations recognized in transition	-	$3.3
Accretion	**0.2**	0.1
Asset retirement obligation at December 31	**$3.6**	$3.4

The Company has an external trust dedicated to funding its joint-ownership share of future decommissioning for Millstone Unit #3. The year-end aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled $4.7 million in 2004 and $4.3 million in 2003, and is included in Investments and Other Assets on the Consolidated Balance Sheets. The year-end difference between the balance in the external trusts and the asset retirement obligation that is recorded in Deferred Credits and Other Liabilities on the Consolidated Balance Sheets amounted to about $1.1 million for 2004 and $0.9 million for 2003.

Other Asset Retirement Obligations The Company's regulated operations collect removal costs in rates for certain utility plant assets that do not have associated legal asset retirement obligations. Non-legal removal costs of about $6.7 million in 2004 and $5.2 million in 2003 have been reclassified from Accumulated Depreciation to Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

Reserve for Loss on Power Contract In accordance with the requirements of SFAS No. 5, *Accounting for Contingencies* ("SFAS No. 5"), in the first quarter of 2004 the Company recorded a $14.4 million pre-tax loss accrual related to termination of its long-term power contract with Connecticut Valley. The contract was terminated as a condition of the Connecticut Valley sale. The loss accrual represented management's best estimate of the difference between expected future sales revenue, in the wholesale market, for the purchased power that was formerly sold to Connecticut Valley and the cost of purchased power obligations. The estimated life of the Company's power contracts that were in place to supply power to Connecticut Valley extends through 2015.

The loss accrual was estimated based on assumptions about future power prices, the reallocation of power from the state-appointed purchasing agent ("VEPPI") and future load growth. Management will review this estimate at the end of each reporting period and will increase the reserve if the revised estimate exceeds the recorded loss accrual. Additionally, the loss accrual will be amortized on a straight-line basis, as required by GAAP, through 2015. In 2004, the Company recorded $1.2 million of amortization. The loss accrual and amortization are included in Purchased Power on the Consolidated Statement of Income in the amount of $13.2 million.

Other Income The pre-tax components of Other Income are as follows (in thousands):

	For the years ended December 31		
	2004	2003	2002
Interest on non-utility notes receivable	**$1,893**	$1,969	$1,493
Non-utility revenue	**1,702**	716	1,953
Interest on temporary investments	**1,436**	540	700
Other interest and dividends	**1,194**	496	763
Regulatory asset carrying costs	**864**	857	342
Amortization of contributions in aid of construction	**829**	795	765
Non-operating rental income	**783**	901	602
Miscellaneous other income	**144**	937	196
Total	**$8,845**	$7,211	$6,814

Other Deductions The pre-tax components of Other Deductions are as follows (in thousands):

	For the years ended December 31		
	2004	2003	2002
Non-utility bad debt expense	**$2,395**	$2,250	$1,627
Non-utility other operating expense	**4,356**	4,017	4,462
Non-utility business development and consulting expense	**860**	2,707	2,729
Asset impairment charges	**203**	42	2,740
Intangible assets amortization	**329**	284	159
Supplemental retirement benefits and insurance	**247**	274	2,122
Other taxes	**190**	306	366
Non-utility expenses	**85**	173	997
Vermont Yankee – one-time payment	**-**	-	955
Miscellaneous other deductions	**590**	802	725
Total	**$9,255**	$10,855	$16,882

Earnings Per Share Basic earnings per share ("EPS") are calculated by dividing net income, after deductions for preferred dividends, by the weighted-average common shares outstanding for the period. SFAS No. 128, *Earnings Per Share*, requires the disclosure of diluted EPS, which is similar to the calculation of basic EPS except that the weighted-average common shares is increased by the number of potential dilutive common shares. Diluted EPS reflects the impact of the issuance of common shares for all potential dilutive common shares outstanding during the period. See Note 5 – Reconciliation of Net Income and Average Shares of Common Stock for additional information.

Stock-Based Compensation The Company applies Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB 25"), and related Interpretations in accounting for its stock option plans. In accordance with SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of SFAS No. 123*, the following table illustrates the effect on net income and EPS as if the fair value method had been applied to all outstanding and unvested awards in each period. The fair value of options at date of grant was estimated using the Black-Scholes option-pricing model for 2004 and 2003 and the binomial option-pricing model for 2002. The Company changed its option-pricing model in 2003 due to the added ease of calculation of the Black-Scholes model. The change in methodology did not materially alter the results of the computation.

(in thousands, except per share amounts)	December 31		
	2004	2003	2002
Income available for common stock, as reported	**$23,387**	$18,603	$18,239
Deduct: Total stock-based employee compensation expense *	**244**	163	147
Pro forma income available for common stock	**$23,143**	$18,440	$18,092
Earnings per share:			
Basic – as reported	**$1.93**	$1.57	$1.56
Basic – pro forma	**$1.91**	$1.55	$1.55
Diluted – as reported	**$1.90**	$1.53	$1.53
Diluted – pro forma	**$1.88**	$1.52	$1.51

* Fair value-based method for all awards, net of related tax effects.

Environmental Liabilities The Company is engaged in various operations and activities that subject it to inspection and supervision by both federal and state regulatory authorities including the United States Environmental Protection Agency. The Company's policy is to accrue a liability for those sites where costs for remediation, monitoring and other future activities are probable and can be reasonably estimated. See Note 13 – Commitments and Contingencies.

Derivative Financial Instruments The Company accounts for various power contracts as derivatives under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended and interpreted. In April 2003, the Financial Accounting Standards Board ("FASB") issued SFAS No. 149, *Amendment of Statement 133 Derivative Instruments and Hedging Activities,* effective for contracts entered or modified after June 30, 2003, which amends and clarifies accounting for derivative instruments under SFAS No. 133 (collectively "SFAS No. 133"). These statements require that derivatives be recorded on the balance sheets at fair value. Adoption and application of these statements did not impact the Company's results of operations.

The Company's long-term contracts for the purchase of power from Vermont Yankee and Independent Power Producers do not meet the definition of a derivative under the requirements of SFAS No. 133 because delivery of power under these contracts is contingent on plant output. Additionally, the long-term power contract with Hydro-Quebec does not meet the definition of a derivative because there is no defined notional amount.

The Company has a long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice (Hydro-Quebec Sellback #3). This contract has been determined to be a derivative under SFAS No. 133. The derivative's year-end estimated fair value was an unrealized loss of $5.7 million in 2004 and an unrealized loss of $1.2 million in 2003. The estimated fair value of this derivative is valued using a binomial tree model, and quoted market data when available along with appropriate valuation methodologies.

In November 2004, the Company entered into two separate forward sale contracts, one through October 2006 and one through December 2008. The sole purpose of entering into these contracts is to manage price risk from power supply resources to minimize the net costs of serving the Company's customers. The Company enters into forward sale contracts when it forecasts excess supply. Both of these forward sale contracts require physical delivery of power, however one is contingent upon Vermont Yankee plant output. The Company has assessed these two contracts and determined that one is a derivative under SFAS No. 133, and the other, due to the unit contingent nature of the contract, is not a derivative. The derivative contract is for delivery of about 15 MW per hour, or a total of 522,544 mWh for the contract term, which extends from November 17, 2004 through December 31, 2008. At December 31, 2004, this contract had an estimated fair value of a $0.4 million unrealized gain. The Company utilized over-the-counter quotations or broker quotes at December 31, 2004 for determining the fair value of this contract.

In December 2003, the Company entered into a forward sale contract for about 148,400 mWh for the period beginning January 1 and ending March 31, 2004, and a forward purchase contract for about 27,100 mWh for the month of April 2004. The purpose of entering into these contracts was to minimize the net costs and risks of serving customers, including replacement power related to Vermont Yankee's April 2004 scheduled refueling outage. The Company determined that these contracts did not meet the normal purchase and sale exclusion under SFAS No. 133. At December 31, 2003, the forward sale contract had an estimated fair value of a $0.4 million unrealized gain, and the forward purchase contract had an estimated fair value of a $0.1 million unrealized loss. The Company utilized over-the-counter quotations or broker quotes at December 31, 2003 for determining the fair value of these contracts. These derivative contracts were settled by December 31, 2004, and are included in Operating Revenue or Purchased

Power on the Consolidated Statement of Income for 2004.

The Company records derivative contracts on the Consolidated Balance Sheets at fair value. Based on a PSB-approved Accounting Order, the Company records the change in fair value of these derivatives as deferred charges or deferred credits on the balance sheet, depending on whether the fair value is an unrealized loss or gain.

Foreign Currency Translation All foreign non-utility assets and liabilities are translated at the year-end currency exchange rate. Revenues and expenses are translated at average exchange rates in effect during the year. Realized gains or losses from foreign currency translations are included in earnings of the current period, and unrealized gains and losses are included in other comprehensive income.

Cash, Cash Equivalents and Restricted Cash The Company considers all liquid investments with an original maturity of three months or less when acquired to be cash and cash equivalents. Restricted cash at December 31, 2004 and 2003 was related to mandatory redeemable preferred stock and included $1 million for the mandatory sinking fund payment and $1 million for the optional sinking fund payment for each year.

Available-for-Sale Securities The Company records available-for-sale securities (short-term and long-term) at fair value. In 2004, the Company began to classify investments in auction rate securities as short-term available-for-sale securities. These amounts were previously recorded in cash and cash equivalents in the consolidated financial statements. The reclassification resulted in changes in the Consolidated Balance Sheets and Consolidated Statements of Cash Flows for the years ended December 31, 2003 and 2002. See Note 8 - Financial Instruments and Investment Securities for additional information.

Supplemental Cash Flow Information Supplemental Cash Flow information is as follows (in thousands):

	For the years ended December 31		
	2004	2003	2002
Cash paid during the year for:			
Interest	**$11,207**	$11,086	$12,657
Income taxes (net of refunds)	**$15,233**	$14,978	$10,773

Auction rate securities Purchases of auction rate securities and proceeds from sale of auction rate securities are included in available-for-sale securities on the Consolidated Statements of Cash Flows.

Non-cash Operating, Investing and Financing Activities For additional information regarding non-cash activities, see Note 9 - Stock Award Plans, Note 12 - Retail Rates, Note 13 - Commitments and Contingencies and discussion of Regulatory Assets above.

Concentration Risk Financial instruments that potentially expose the Company to concentrations of credit risk consist primarily of cash, cash equivalents, available-for-sale securities, notes receivable and accounts receivable.

The Company maintains a significant portion of its invested cash with numerous creditworthy issuers placed through major financial institutions. The Company's available-for-sale securities (current and non current) are invested in auction rate securities and in a bond portfolio managed by one investment manager. Auction rate securities generally have a credit quality of AAA. The bond portfolio is comprised of U.S. government obligations, U.S. government agency obligations and high-quality corporate bonds. At December 31, 2004, the average credit quality of the bond portfolio was AA, and is subject to gains and losses primarily in response to interest rate changes. The remaining invested cash consists of high-quality money market funds and cash equivalents.

The Company's accounts receivables are not collateralized. As of December 31, 2004, about 15 to 20 percent of total accounts receivable are with wholesale entities engaged in the energy industry. This industry concentration could affect the Company's overall exposure to credit risk, positively or negatively, since customers may be similarly affected by changes in economic, industry or other conditions. The Company believes the credit risk posed by industry concentration is offset by the diversification and creditworthiness of its retail electric customer base of residential, commercial and industrial customers.

Our material power supply contracts and arrangements are principally with Hydro-Quebec and Vermont Yankee Nuclear Power Corporation. These contracts supported about 84 percent of our total energy (mWh) purchases in 2004. These supplier concentrations could have a material impact on the Company's power costs, if one or both of these sources were unavailable over an extended period of time.

Catamount had notes receivable of $29.2 million at December 31, 2004, including two separate notes for wind project development sites located in Nolan County, Texas. The first is a $22.6 million construction note for a wind project under construction, referred to as Sweetwater 2, and is collateralized by the wind project's assets. The second is a $6.6 million note receivable associated with the future development at the site, and is collateralized primarily by the remaining site land leases and related interconnection agreement. See Note 3 – Non-utility Investments.

Reclassifications The Company will record reclassifications to the financial statements of prior years when considered necessary or to conform to current-year presentation. The reclassification of auction rate securities from cash and cash equivalents to short-term available-for-sale securities resulted in a $34.4 million change to those line items on the Consolidated Balance Sheet for 2003, and changes to the Consolidated Statements of Cash Flows within the cash and cash equivalents balances and investing activities, and impacted cash flows used in investing activities by $27.3 million for 2003 and $2.2 million for 2002. There was no impact on net income, cash flow from operations, total assets or covenants as a result of this reclassification.

Recent Accounting Pronouncements

Medicare Prescription Drug, Improvement and Modernization Act of 2003 ("the Act"): In December 2003, the Act was signed into law. The Act introduces a voluntary prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care plans that provide at least an actuarially equivalent benefit to Medicare Part D. As a result, on May 19, 2004, the FASB issued FASB Staff Position ("FSP") No. FAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*, ("FSP FAS 106-2") which superseded FSP FAS 106-1, which allowed employers to voluntarily recognize the impact of the Act. Currently, SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, requires that changes in relevant law be considered in current measurement of postretirement benefit costs. The Company had elected to defer recognition of any impact under FSP FAS 106-1. FSP FAS 106-2 provides that if the effect of the Act is not considered a significant event, the measurement date for adoption of FSP FAS 106-2 is delayed until the next regular measurement date. The annual savings is estimated to be about $0.2 million and therefore, the Company has concluded that the effect is not significant. In January 2005, the US Department of Health and Human Services issued regulations that define actuarial equivalency. The Company is in the process of evaluating the impacts of the regulations.

Financial Instruments: In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with the Characteristics of Both Liabilities and Equity*. This statement establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity. This statement was effective beginning with the first interim period after June 30, 2003. The Company implemented the income statement impacts in 2004, and reclassified $0.7 million of dividends on its mandatorily redeemable preferred stock from Preferred Stock Dividend Requirements to Interest Expense in the Consolidated Statement of Income for the year ended December 31, 2004.

Variable Interest Entities: In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities* ("FIN 46"), and in December 2003 the FASB issued its revision ("FIN 46R") which addressed the requirements for consolidating certain variable interest entities ("VIEs"). This interpretation clarified application of Accounting Research Bulletin No. 51, *"Consolidated Financial Statements,"* and replaced accounting guidance relating to consolidation of certain special purpose entities. FIN 46 and FIN 46R define VIEs as entities that are unable to finance their ongoing operations without additional subordinated financing. FIN 46R requires identification of the Company's participation in VIEs and consolidation of those VIEs of which the Company is the primary beneficiary. The Company adopted FIN 46 at December 31, 2003 and FIN 46R at March 31, 2004, and determined that it did not have any VIEs. See Note 2 – Investments in Affiliates.

Investments in Debt and Equity Securities not Accounted for Using the Equity Method: In June 2004, the FASB issued EITF 03-1, *The Meanings of Other-Than-Temporary Impairment and Its Application to Certain Investments* ("EITF 03-1"), which prescribes a common approach to evaluating other-than-temporary impairment of investments in debt and equity securities not accounted for using the equity method of accounting for certain equity investments. Implementation of EITF 03-1 has been delayed, with the exception of certain disclosure requirements, by FASB Staff Position ("FSP") EITF Issue 03-1-1, until the guidance contained in proposed FSP EITF Issue 03-1-a, *Implementation Guidance for the Application of Paragraph 16 of EITF Issue No. 03-1* ("FSP EITF 03-1-a") has been finalized. The Company adopted the disclosure requirements of EITF 03-1 as of December 31, 2003, as required. The Company cannot predict the impact on its financial statements, if any, related to adoption of EITF 03-01 until a final version of the implementation guidance is available. See Note 8 – Financial Instruments and Investment Securities.

American Jobs Creation Act of 2004 ("Act"): In December 2004, FASB issued FSP FAS 109-1, *Application of FASB Statement No. 109, 'Accounting for Income Taxes,' to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004.* The Act included tax relief for domestic manufacturers (including the production, but not the delivery of electricity) by providing a tax deduction up to 9 percent (when fully phased-in in 2010) on a percentage of "qualified production activities income." The deduction for 2005 and 2006 is 3 percent, and increases to 6 percent for 2007, 2008 and 2009. The FASB staff has indicated that this tax relief should be treated as a special deduction and not as a tax rate reduction. The U.S. Treasury has issued general guidance on the calculation of the deductions, but this guidance lacks clarity as to the determination of qualified production activities as it relates to utility operations. The Company believes that the special deduction for 2005 and thereafter will not materially affect its results of operations, cash flows, or financial condition.

The Act included a one-time deduction of 85 percent of foreign earnings that are repatriated in 2004 and 2005. Due to lack of clarification of certain of the provisions of the Act, the FASB is allowing more time for companies to evaluate the impacts, before disclosing its impact. The Company believes that the foreign dividend received deduction will not materially affect its results of operations, cash flow, or financial condition.

Share-Based Payments: In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment* ("SFAS No. 123R"). This Statement is a revision of SFAS No. 123 *Accounting for Stock-Based Compensation,* and supersedes Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees,* and its related implementation guidance. SFAS No. 123R focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. The statement requires entities to recognize stock compensation expense for awards of entity instruments to employees based on the grant-date fair value of those awards (with limited exceptions). SFAS No. 123R is effective for the first interim or annual reporting period that begins after June 15, 2005. The Company is currently evaluating the two methods of adoption, modified-prospective transition method and modified-retrospective transition method, allowed by SFAS No. 123R. The Company does not expect that adoption of SFAS No. 123R will have a material impact on its financial position or results of operations.

Inventory Costs: In December 2004, FASB issued SFAS No. 151, *Inventory Costs,* ("SFAS No. 151") which clarifies the treatment of abnormal freight, handling, and waste costs associated with inventories. This statement requires that abnormal freight, handling, and waste costs be recognized as current expenses and is effective for fiscal years beginning after June 15, 2005. The Company has not determined the impact, if any, adoption of SFAS No. 151 will have on its financial position or results of operations.

NOTE 2 – INVESTMENTS IN AFFILIATES

The Company's equity method investments are as follows (in thousands):

	Ownership	December 31 2004	2003
Vermont Yankee Nuclear Power Corporation (1)	58.85%	**$2,822**	$2,810
Vermont Electric Power Company, Inc. (2):			
Common stock	47.02%	**11,296**	4,295
Preferred stock	48.03%	**316**	422
Subtotal		**11,612**	4,717
Nuclear generating companies:			
Connecticut Yankee Atomic Power Company	2.00%	**883**	943
Maine Yankee Atomic Power Company	2.00%	**714**	793
Yankee Atomic Electric Company	3.50%	**39**	40
Subtotal		**1,636**	1,776
Total Investment in Affiliates		**$16,070**	$9,303

(1) The Company's ownership percentage changed from 33.23 percent to 58.85 percent on November 7, 2003.
(2) The Company's common stock ownership (voting and non-voting) changed from 50.49 percent to 47.02 percent in December 2004.

The Company transferred its shares of Vermont Yankee to Custom Investment Corporation ("Custom"), a wholly owned passive investment subsidiary, on October 10, 2003, per PSB approval. The transfer to Custom does not affect the Company's rights and obligations related to Vermont Yankee Nuclear Power Corporation.

Vermont Yankee Nuclear Power Corporation ("VYNPC") Summarized financial information is as follows (in thousands):

Earnings	For the Years Ended December 31 2004	2003	2002
Operating revenues	$167,399	$187,123	$175,722
Operating income	$87	$668	$6,949
Net income	$538	$2,536	$9,454
Company's equity in net income	$316	$985	$3,141

Investment	December 31 2004	2003
Current assets	$24,600	$20,297
Non-current assets	126,942	131,834
Total Assets	151,542	152,131
Less:		
Current liabilities	18,290	18,426
Non-current liabilities	128,457	128,931
Net assets	$4,795	$4,774
Company's equity in net assets	$2,822	$2,810

VYNPC sold its nuclear plant to Entergy Nuclear Vermont Yankee, LLC ("ENVY") on July 31, 2002. The sale agreement included a purchased power contract ("PPA"), which VYNPC administers among the former plant owners and ENVY. Under the PPA between ENVY and VYNPC, VYNPC pays ENVY for generation at fixed rates. VYNPC, in turn, bills the PPA charges from ENVY with certain residual costs of service through a FERC tariff to the Company and the other VYNPC sponsors. VYNPC's revenues shown in the table above include sales to the Company of $58.3 million in 2004, $65.2 million in 2003 and $60.2 million in 2002. These purchases are included in Purchased Power on the Consolidated Statements of Income. Accounts payable to VYNPC amounted to $5.8 million at December 31, 2004 and $4.6 million at December 31, 2003.

In November 2003, the Company's ownership interest in VYNPC increased from 33.23 percent to 58.85 percent as a result of the repurchase of shares held by certain non-Vermont sponsors. The non-Vermont sponsors remain obligated under all agreements with VYNPC, including their power purchase obligations under the VYNPC power contract with ENVY. Although the Company owns a majority of the shares of VYNPC, the Power Contracts, Sponsor Agreement and composition of the Board of Directors, under which it operates, effectively restrict the Company's ability to exercise control over VYNPC. Additionally, the Company has concluded, based on the provisions of FIN 46R, that VYNPC is not a VIE. Therefore, its financial statements have not been consolidated into the Company's financial statements.

In 2004, the Company received $0.3 million of cash dividends from VYNPC. In 2003, the Company received $14.3 million ($13.7 million return of capital and $0.6 million cash dividends) related to the 2002 sale of the plant. The sale resulted in a gain of about $0.1 million recorded in 2003.

See Note 13 – Commitments and Contingencies, for additional information regarding the Company's long-term power contract with VYNPC.

Vermont Electric Power Company, Inc. ("VELCO") Summarized financial information is as follows (in thousands):

Earnings	For the Years Ended December 31 2004	2003	2002
Transmission revenues	$23,351	$23,107	$20,257
Operating income	$7,008	$5,533	$5,091
Net income	$1,683	$1,270	$1,094
Company's equity in net income	$822	$675	$516

Investment	December 31 2004	2003
Current assets	$22,699	$25,996
Non-current assets	122,947	100,671
Total assets	145,646	126,667
Less:		
Current liabilities	52,469	58,698
Non-current liabilities	68,528	58,569
Net assets	$24,649	$9,400
Company's equity in net assets	$11,611	$4,717

VELCO and its wholly owned subsidiary, Vermont Electric Transmission Company, Inc., own and operate an integrated transmission system in Vermont over which bulk power is delivered to all electric utilities in the State. VELCO has entered into transmission agreements with the State of Vermont and all of the Vermont electric utilities. Under these agreements, it bills all costs, including interest on debt and a fixed return on equity, to the State, utilities and others that use the system. These contracts enable VELCO to finance its facilities primarily through the sale of first mortgage bonds.

VELCO is also a participant with all of the major electric utilities in New England in the New England Power Pool, ("NEPOOL") acting for itself and as agent for the twenty-one other electric utilities in Vermont, including the Company. The generating and transmission facilities of all of the participants are coordinated on a New England-wide basis through a central dispatching agency to assure their operation and maintenance in accordance with proper standards of reliability, and to attain the maximum practicable economy for all participants through the interchange of economy and emergency power.

VELCO bills the Company on a monthly basis for transmission and administrative costs associated with power and transmission services; these billings include various credits such as those from ISO-New England under the NEPOOL Open Access Transmission Tariff ("NOATT"). Such billings amounted to $6.3 million in 2004, $12.0 million in 2003 and $12.6 million in 2002, and are reflected as production and transmission expenses in the accompanying Consolidated Statements of Income. Prior to May 2004, VELCO also billed the Company for its share of NOATT charges, which are now billed directly to the Company from ISO-New England. Of the amounts billed by VELCO, about $5.3 million in 2004, $10.7 million in 2003 and $11.7 million in 2002 are included in VELCO's revenues shown above. Accounts payable to VELCO amounted to $4.8 million at December 31, 2004 and $6.2 million at December 31, 2003.

On August 17, 2004, FERC approved a joint filing by the Company and Green Mountain Power ("GMP") for authorization to purchase stock to be issued by VELCO in 2004 and 2005 in connection with financing its planned transmission upgrades. In December 2004, the Company invested about $7 million in VELCO's voting Class B common stock, changing its common stock ownership (voting and non-voting) to 47.02 percent from 50.49 percent. In the third quarter of 2003, the Company purchased additional shares of VELCO's non-voting Class C common stock for about $0.2 million, changing its ownership from 50.65 percent to 50.49 percent. The decrease in ownership percentage reflects acquisitions of voting and non-voting common stock issued by VELCO in amounts below the Company's pro-rata ownership at the time of purchase. The 2003 acquisition resulted from FERC's August 2003 approval of a joint request by the Company and GMP for each to purchase certain shares of non-voting Class C common stock issued by VELCO to provide working capital, maintain a debt-to-equity ratio within the guidelines of VELCO's Articles of Association, and realign equity ownership as close as possible to entitlement levels of VELCO's transmission services.

VELCO operates pursuant to the terms of the 1985 Four-Party Agreement (as amended) with the Company and two other major distribution companies in Vermont. Although the Company owns a majority of the shares of VELCO, the Four-Party Agreement does not provide the Company ability to exercise control over VELCO. Additionally, the Company assessed its ownership interest in VELCO under the provisions of FIN 46R and concluded that VELCO is not a VIE. Therefore, VELCO's financial statements have not been consolidated.

In 2004, the Company received about $0.9 million in dividends from VELCO. Of that amount about $0.1 million was related to return of capital from VELCO's Class C preferred stock and $0.1 million was related to an accrual for dividends declared in December 2004 for payment in January 2005. In 2003, the Company received about $0.7 million in dividends from VELCO including about $0.1 million related to the return of capital from VELCO's Class C preferred stock.

Nuclear Generating Companies The Company is one of several sponsor companies with ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic, and is responsible for paying its ownership percentage of decommissioning and all other costs for each plant. The Company also has a 1.7303 percent joint-ownership interest in Millstone Unit #3. Its obligations related to that plant are described in more detail in Note 13 – Commitments and Contingencies. The Maine Yankee, Connecticut Yankee and Yankee Atomic nuclear plants have been shut down and are undergoing decommissioning. Information related to decommissioning and closure costs, including the Company's share of estimated future payments for each plant, are as follows (dollars in millions):

	Date of Study	Total Expenditures (a)	Remaining Obligation (b)	Revenue Requirements (c)	Company Share (d)
Maine Yankee	2003	$485.4	$173.0	$292.1	$5.8
Connecticut Yankee	2003	$639.5	$362.6	$630.0	$12.6
Yankee Atomic	2003	$479.7	$160.9	$119.3	$4.2

(a) Total cumulative decommissioning expenditures incurred through 2004, net of proceeds received from various legal matters settled prior to December 31, 2004.

(b) Estimated remaining decommissioning costs in 2004 dollars for the period 2005 through 2023 for Maine Yankee and Connecticut Yankee, and through 2022 for Yankee Atomic.

(c) Estimated future payments required by Sponsor companies to recover estimated decommissioning and all other costs for 2005 and forward, in nominal dollars. For Maine Yankee and Connecticut Yankee includes collections for required contributions to spent fuel funds as described below. Yankee Atomic has already collected and paid these required contributions.

(d) Represents the Company's share of revenue requirements based on its ownership percentage in each plant.

Maine Yankee, Connecticut Yankee and Yankee Atomic are seeking recovery of fuel storage-related costs stemming from the default of the United States Department of Energy ("DOE") under the 1983 fuel disposal contracts that were mandated by the United States Congress under the High Level Waste Act. All three are parties to a lawsuit against the DOE seeking damages based on the DOE's default. The trial on determination of damages began on July 12 and ended August 31, 2004. Closing arguments were held in January 2005 and final post-trial briefs were filed in February 2005. A decision is expected by the end of 2005; however, an appeal by at least one of the parties is likely. None of the plants has included any allowance for potential recovery of these claims in their FERC-filed cost estimates.

The Company's share of Maine Yankee, Connecticut Yankee and Yankee Atomic estimated costs are reflected on the Consolidated Balance Sheets as regulatory assets or other deferred charges, and nuclear decommissioning liabilities (current and non-current). These amounts are adjusted when revised estimates are provided by the companies. At December 31, 2004, the Company had regulatory assets of about $5.8 million related to Maine Yankee and $2.1 million related to Connecticut Yankee. These estimated costs are being collected from the Company's customers through existing retail rate tariffs. At December 31, 2004, the Company also had other deferred charges related to incremental dismantling costs of about $10.5 million for Connecticut Yankee and $7.2 million for Yankee Atomic. These amounts include payments of about $0.1 million to Connecticut Yankee and $3.0 million to Yankee Atomic, representing the Company's share of the respective companies' collection of incremental costs as of December 31, 2004. These incremental dismantling costs are not being recovered through existing retail rate tariffs, and are being deferred based on an October 2003 PSB-approved Accounting Order for treatment of these incremental costs as deferred charges, to be addressed in the Company's pending rate proceeding.

Maine Yankee, Connecticut Yankee and Yankee Atomic collect decommissioning and closure costs through wholesale FERC-approved rates charged under power agreements with several New England utilities, including the Company. Historically, the Company's share of these costs has been recovered from its retail customers through PSB-approved rates. Based on the regulatory process, management believes its share of decommissioning and closure costs for each plant will continue to be recovered through the regulatory process. Although Management believes that the decommissioning and closure costs will ultimately be recovered from its customers, there is a risk that the FERC may not allow full recovery of Connecticut Yankee's incremental increased costs in wholesale rates. If FERC does not allow these costs to be recovered in wholesale rates, the Company anticipates that the PSB would disallow these costs for recovery in retail rates as well. See discussion below for additional information related to Maine Yankee, Connecticut Yankee and Yankee Atomic.

Maine Yankee: The Company has a 2 percent ownership interest in Maine Yankee. Billings from Maine Yankee to the Company amounted to about $1.3 million in 2004, $1.1 million in 2003 and $1.1 million in 2002, and are included in Purchased Power on the Consolidated Statements of Income. Accounts Payable to Maine Yankee for 2004 and 2003 were of a nominal amount. In October 2003, Maine Yankee filed a FERC rate proceeding for collection of estimated decommissioning and long-term spent fuel storage costs. In July 2004, Maine Yankee and various other parties agreed to an Offer of Settlement resolving all issues raised by the rate case participants. On September 16, 2004, FERC approved the settlement, which provides for recovery of all of Maine Yankee's forecasted costs of providing service through a formula rate contained in its power contracts through October 31, 2008 and replenishment of the DOE Spent Fuel Obligation through collections from November 2008 through October 2010.

From January 1 through October 31, 2004, Maine Yankee's billings to sponsor companies were based on its FERC filing subject to refund. Beginning November 1, 2004, Maine Yankee's billings have been based on the FERC-approved settlement, reduced for excess collections that occurred prior to the effective date.

Connecticut Yankee: The Company has a 2 percent ownership interest in Connecticut Yankee. Billings from Connecticut Yankee to the Company amounted to $0.9 million for 2004, $0.9 million for 2003 and $0.9 million for 2002, and are included in Purchased Power on the Consolidated Statements of Income. Accounts Payable to Connecticut Yankee for 2004 and 2003 were of a nominal amount. Costs currently billed by Connecticut Yankee are based on its most recent FERC-filed rates, which became effective February 1, 2005, for collection through 2010, subject to refund, and pending a final order by FERC. Prior to February 1, 2005, costs were billed by Connecticut Yankee based on its FERC-approved rates that became effective September 1, 2000, for collection through 2007.

Connecticut Yankee is currently involved in litigation related to a contract dispute. Also in 2004, Connecticut Yankee filed a rate application with FERC. These matters are discussed in more detail below.

Bechtel Litigation: Connecticut Yankee is involved in a contract dispute with Bechtel Power Corporation ("Bechtel"), which resulted in termination of the decommissioning services contract between Connecticut Yankee and Bechtel. The lawsuit has been assigned to the Complex Litigation Docket and has been set for a jury trial beginning May 4, 2006. Connecticut Yankee also notified Bechtel's surety of its intention to file a claim under the performance bond.

On June 18, 2004, Bechtel filed a Pre-Judgment Remedy Application ("PJR") requesting a $93 million garnishment of the Decommissioning Trust ("Trust"), Connecticut Yankee shareholder payments to the Trust and any proceeds from the fuel disposal contract litigation pending between Connecticut Yankee and the DOE, as well as attachment of any Connecticut Yankee assets, including the Haddam Neck real property. On July 16, 2004, Connecticut Yankee filed its Objection to the PJR. On July 20, 2004, the Court allowed the Connecticut Department of Public Utility Control ("CT DPUC") to intervene in the PJR proceeding for the limited purpose of objecting to Bechtel's requested garnishment of the Trust and related payments. The Court held hearings on these matters in August and October 2004. On October 29, 2004, Bechtel and Connecticut Yankee entered into an agreement that made additional hearings unnecessary. Bechtel agreed to withdraw its request for an attachment of the Decommissioning Trust Fund and related payments, in return for potential attachment of Connecticut Yankee's real property in Connecticut with a book value of $7.9 million and the escrowing of $41.7 million the sponsors are scheduled to pay to Connecticut Yankee through June 30, 2007. This agreement is subject to approval of the Court and would not be implemented until the Court found that such assets were subject to attachment. Connecticut Yankee intends to contest the attachability of such assets. The agreement does not materially change the legal positions in this litigation. The CT DPUC did not object to the agreement.

FERC Rate Case Filing: In December 2003, Connecticut Yankee's Board of Directors endorsed an updated estimate ("2003 Estimate") of the costs for the plant's decommissioning project. This updated estimate reflects the fact that Connecticut Yankee is now directly managing the work (self-performing) to complete decommissioning of the plant following the default termination of Bechtel. The 2003 Estimate of approximately $831.3 million covers the time period 2000 – 2023 and represents an aggregate increase of approximately $395 million in 2003 dollars over the costs estimate in its 2000 FERC rate case settlement, which covered the same time period. The new cost estimate includes the cost of providing service under the formula rate contained in its FERC tariff, including decommissioning costs, as well as the replenishment of the Spent Fuel Trust Fund, which has been combined with the Decommissioning Trust Fund.

On June 10, 2004, the CT DPUC and the Connecticut Office of Consumer Counsel ("OCC") filed a petition ("Petition") with FERC seeking a declaratory order that Connecticut Yankee can recover all decommissioning costs from its sponsor companies, but that those purchasers may not recover in their retail rates any costs that FERC might determine to be imprudently incurred. Connecticut Yankee and its sponsor companies, including the Company, have responded in opposition to the Petition, indicating that the order sought by the CT DPUC would violate the Federal Power Act and decisions of the United States Supreme Court, other federal and state courts, and FERC. The NHPUC filed an intervention notice in support of the Petition. Bechtel has filed an amicus brief and intervention notice in support of the Petition.

On July 1, 2004, Connecticut Yankee filed the 2003 Estimate with the FERC as part of its rate application ("Filing") seeking additional funding to complete the decommissioning project and for storage of spent fuel through 2023. The Filing requested that new rates become effective January 1, 2005. The Filing includes proposed increased decommissioning charges, based on the 2003 Estimate, as well as new annual charges for pension expense and costs of funding post-employment benefits other than pensions. The proposed annual decommissioning collection represents a significant increase in annual charges to the sponsor companies, including the Company, as compared to the existing FERC rates.

On July 6, 2004, FERC issued a notice of the Filing indicating that intervention and protest filings would be due by July 22; however, that date was extended to July 30, at the request of the CT DPUC. Four non-utility interventions have been filed at the FERC by the CT DPUC, the OCC, Bechtel and the Massachusetts Attorney General. On August 30, 2004, FERC issued an order: 1) accepting for filing the new charges proposed by Connecticut Yankee; 2) suspending these revised charges until February 1, 2005; 3) establishing Administrative Law Judge hearing procedures and schedules; 4) denying the request of the CT DPUC and OCC for both an accelerated hearing schedule and for a bond or other security for potential refunds; 5) denying the declaratory ruling sought by the CT DPUC and OCC; and 6) granting motions to intervene for Bechtel and other applying parties. On September 7, 2004, a FERC administrative law judge was appointed to the case.

On February 22, 2005, the CT DPUC filed testimony with FERC. In its filed testimony, the CT DPUC argues that about $215 million to $225 million of Connecticut Yankee's requested increase is due to Connecticut Yankee's imprudence in managing the decommissioning project while Bechtel was the contractor. Therefore, the CT DPUC recommends a total disallowance of $225 million to $234 million. The current schedule provides for the hearings to start June 1, 2005. Connecticut Yankee anticipates that the process of resolving the matters in the Filing is likely to be contentious and lengthy.

The Company's estimated aggregate obligation related to Connecticut Yankee is about $12.6 million. The Company continues to believe that FERC will approve recovery of these increased costs in wholesale rates based on the nature of costs and previous rulings at other nuclear companies. Once approved by FERC, the Company believes it is unlikely that the PSB would not allow these FERC-approved costs to be recovered in retail rates. If FERC adopts the CT DPUC's recommendations described above, the Company's share of the proposed disallowance would be about $4.7 million. The timing, amount and outcome of the Bechtel litigation and FERC rate case filing cannot be predicted at this time.

Yankee Atomic: The Company has a 3.5 percent ownership interest in Yankee Atomic. Billings from Yankee Atomic to the Company amounted to $1.9 million for 2004 and $1.1 million for 2003, and are included in Purchased Power on the Consolidated Statements of Income. Accounts Payable to Yankee Atomic for 2004 and 2003 were of a nominal amount. Billings from Yankee Atomic ended in July 2000 based on Yankee Atomic's determination that it had collected sufficient funds to complete the decommissioning effort. The Company is not currently collecting Yankee Atomic costs in retail rates.

In April 2003, Yankee Atomic filed with FERC, based on updated cost estimates, for new rates to collect these costs from sponsor companies. FERC approved the resumption of billings starting June 2003 for a recovery period through 2010, subject to refund. On August 6, 2003, Yankee Atomic filed a Settlement Agreement that resolved all issues raised by the parties. Beginning April 2004 and each year following, the new rates are subject to an annual adjustment based on the prior calendar year's data if the decommissioning trust fund market performance is 10 percent greater or 10 percent less than the assumptions used to calculate the schedule of decommissioning charges. As such, a reduction was applied to filed-rates beginning with April 2004 billings.

NOTE 3 - NON-UTILITY INVESTMENTS

Catamount Catamount invests in unregulated energy generation projects primarily in the United States and United Kingdom. As of December 31, 2004, Catamount has interests in six operating independent power projects located in Rumford, Maine; East Ryegate, Vermont; Hopewell, Virginia; Nolan County, Texas; Thuringen, Germany and Mecklenburg-Vorpommern, Germany. The operating project in Hopewell, Virginia ended commercial operation in October 2004 and the partnership is finalizing its business operations.

Eversant Eversant has a $1.4 million equity investment, representing a 12 percent ownership interest in The Home Service Store, Inc. ("HSS"), as of December 31, 2004. HSS has established a network of affiliate contractors who perform home maintenance repair and improvements for HSS members. Eversant accounts for this investment on a cost basis.

Certain financial information related to these investments follows (in thousands):

Catamount Projects:	Location	Generating Capacity	Fuel	In-Service Date	Ownership	Investment December 31 2004	Investment December 31 2003	Investment Distribution 2004	Investment Distribution 2003
Rumford Cogeneration	Maine	85 MW	Coal/Wood	1990	15.1%	**$13,291**	$16,122	**$4,110**	$4,094
Ryegate Associates	Vermont	20 MW	Wood	1992	33.1%	**4,115**	4,220	**2,339**	5,341
Appomattox Cogeneration	Virginia	41 MW	Coal/Biomass/ Black liquor	1982	25.3%	**-**	2,429	**3,908**	3,409
Rupert Cogeneration Partners	Idaho	10 MW	Gas	1996	50.0%	**-**	342	**-**	71
Glenns Ferry Cogeneration	Idaho	10 MW	Gas	1996	50.0%	**-**	205	**-**	-
Sweetwater Wind 1 LLC	Texas	37.5 MW	Wind	2003	30.5%	**5,782**	6,212	**595**	-
Fibrothetford Limited	England	38.5 MW	Biomass	1998	44.7%	**-**	3,233	**-**	-
DK Burgerwindpark Eckolstadt	Germany	14.3 MW	Wind	2000	10.0%	**544**	451	**-**	-
DK Windpark Kavelstorf GmbH&Co. KG	Germany	7.2 MW	Wind	2001	10.0%	**197**	190	**-**	-
Other	Various		Wind			**380**	-	**-**	-
Subtotal Catamount projects						**24,309**	33,404	**10,952**	12,915
Eversant Investment in HSS	Various in U.S.	n/a	n/a	n/a	12.0%	**1,361**	1,361	**-**	-
Total Non-Utility Investments						**$25,670**	$34,765	**$10,952**	$12,915

Catamount Operations

Catamount is wholly focused on development, ownership and asset management of wind energy projects, and it has projects under development in the United States and United Kingdom. In January 2004, Catamount Energy Limited and Catamount Cymru Cyf. issued stock to a third-party Norwegian investor, thereby diluting Catamount's interest to 50 percent. The issuance resulted in no gain or loss. In July 2003, Catamount established Catamount Cymru Cyf., an English and Welsh private limited company, to develop a project located in Wales.

Catamount had Notes Receivable of $29.2 million, net of an allowance of $0.3 million, at December 31, 2004. The Notes Receivable includes two separate notes for wind project development sites located in Nolan County, Texas. One of the notes is a $22.6 million construction note for construction of the Sweetwater 2 wind project, and the other is a $6.6 million note associated with future development at the site. Catamount also has a $0.3 million note, which has been fully reserved, related to the sale of a development project in the United States.

Catamount's 2004 earnings totaled $3.6 million, including $2.9 million of net income tax benefits and $1.5 million of after-tax gains associated with the sales of the Fibrothetford, Rupert and Glenns Ferry investment interests. Also included was a fee associated with Catamount's United Kingdom development effort. Catamount's 2003 earnings were $0.7 million, including a $2.3 million reduction of income tax valuation allowances associated with previously recorded equity losses resulting from asset impairment for the Fibrothetford, Rupert and Glenns Ferry investments. The 2003 reduction in income tax valuation allowances resulted in a benefit to the consolidated federal income tax provision due to management's best estimate that the Company would receive capital gains treatment on the Connecticut Valley sale. Catamount's 2002 earnings totaled $1.5 million.

Catamount, or its wholly owned subsidiaries provide certain management, accounting and other services to certain entities in which Catamount holds an equity interest. The fees are designed to recover actual costs or are agreed upon by other equity investors in these entities. All fees are billed monthly with the exception of one that is billed annually. Additionally, all fees are payable monthly except for one in which fees are payable upon receipt of dividends from its wholly owned subsidiaries. Catamount's revenues, included in Other Income on the Consolidated Statements of Income, included billings of $0.6 million in 2004, $0.5 million in 2003 and $0.6 million in 2002. Accounts Receivable for these billings amounted to $0.6 million in 2004, of which $0.5 million has been reserved for 2004, and $0.2 million in 2003. Also included in Catamount's 2004 Accounts Receivable are fees of about $0.5 million from a windfarm under construction in which Catamount has an ownership interest.

Appomattox In October 2004, the partnership's long-term lease with the steam host ended. The partnership is finalizing its business operations and in December 2004 most of the project's remaining cash, was distributed to the partners. In December 2004, Catamount recorded a nominal impairment associated with its general partner interest in the partnership.

Glenns Ferry and Rupert On July 1, 2004, Catamount completed the sale of its investment interests in Glenns Ferry and Rupert to a third party. The sale resulted in an after-tax gain of about $0.6 million and an additional $0.2 million of income tax benefits associated with the sale. As described above, in the third quarter of 2003, Catamount recorded a $0.6 million benefit related to the reduction of income tax valuation allowances associated with its investments in Glenns Ferry and Rupert.

Sweetwater 1 In December 2003, Catamount acquired an equity interest of $6.2 million in Sweetwater 1, a 37.5-MW wind farm in Nolan County, Texas.

Fibrothetford Limited In September 2004, Catamount entered into separate Sales and Purchase Agreements with a third party for the sale of its Fibrothetford note receivable and equity investment. The note receivable was sold in September 2004, resulting in an after-tax gain of $0.6 million. Its equity investment was sold in October 2004, resulting in an after-tax gain of about $0.3 million. Both the sale of the note receivable and equity investment resulted in additional income tax benefits of $0.2 million and $2.5 million, respectively. As described above, in the third quarter of 2003, Catamount recorded a $1.7 million benefit related to the reduction of income tax valuation allowances associated with its investments in Fibrothetford.

To the extent required, continuing equity losses were applied as a reduction to Catamount's note receivable balance from Fibrothetford. In 2004 and 2003, Catamount reserved approximately $1.7 million and $2 million, respectively, against interest income on the note receivable.

DK Burgerwindpark Eckolstadt and DK Windpark Kavelstorf GmbH&Co. KG (collectively "Eurowind") In December 2004, Catamount recorded an after-tax impairment of $0.2 million related to its Eurowind investments. The impairment reflects Management's best estimate of the current market value of these investments.

Eversant Operations

In addition to its HSS investment described above, Eversant's wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. ("SEWHS"), engages in the sale or rental of electric water heaters in Vermont and New Hampshire. Eversant had earnings of $0.4 million in 2004 and $0.5 million in 2003, versus a net loss of $0.5 million in 2002. In early 2002, the Company decided to discontinue Eversant's efforts to pursue unregulated business opportunities except for SEWHS.

NOTE 4 - DISCONTINUED OPERATIONS

On January 1, 2004, Connecticut Valley completed the sale of substantially all of its plant assets and its franchise to PSNH. The sale, including termination of the power contract between the Company and Connecticut Valley, resolved all Connecticut Valley restructuring litigation in New Hampshire and the Company's stranded cost litigation at FERC.

Cash proceeds from the sale amounted to about $30 million, with $9 million representing the net book value of Connecticut Valley's plant assets plus certain other adjustments, and $21 million as described below. In return, PSNH acquired Connecticut Valley's franchise, poles, wires, substations and other facilities, and several independent power obligations.

As a condition of the sale, Connecticut Valley paid the Company $21 million to terminate its long-term power contract. In accordance with SFAS No. 5, in the first quarter of 2004, the Company recorded a $14.4 million pre-tax loss accrual related to termination of the power contract. The loss accrual represents Management's best estimate of the difference between expected future sales revenue, in the wholesale market, for the purchased power that was formerly sold to Connecticut Valley and the cost of purchased power obligations. See Reserve for Loss on Power Contract in Note 1 - Summary of Significant Accounting Policies for information regarding the loss accrual.

For accounting purposes, components of the sale transaction are recorded in both continuing and discontinued operations in the Consolidated Statement of Income. In 2004, income from discontinued operations included a gain on disposal of about $21 million, pre-tax, or $12.3 million, after-tax, reflecting the $30 million payment from PSNH, net of various other adjustments. In addition to the gain on disposal of discontinued operations, the Company recorded a loss on power costs, net of tax, of $8.4 million relating to termination of the power contract with Connecticut Valley. The loss is included in Purchased Power on the Consolidated Statement of Income. When the two accounting transactions are combined to assess the total impact of the sale, the result is a gain of $3.9 million recorded in 2004.

On January 1, 2004, Connecticut Valley also paid in full a $3.8 million inter-company promissory note due to the Company. There are no remaining significant business activities related to Connecticut Valley. Summarized results of operations of the discontinued operations are as follows (in thousands):

	For the years ended December 31		
	2004	2003	2002
Operating revenues	**$23**	$19,728	$20,242
Operating expenses			
Purchased power	**-**	14,725	15,283
Other operating expenses	**43**	2,049	1,989
Income tax (benefit) expense	**(7)**	1,232	1,224
Total operating expenses	**36**	18,006	18,496
Operating (loss) income	**(13)**	1,722	1,746
Other expense, net	**(1)**	(276)	(203)
Net (loss) income, net of tax	**(14)**	1,446	1,543
Gain from disposal, net of $8,706 tax	**12,354**	-	-
Income from discontinued operations, net of tax	**$12,340**	$1,446	$1,543

Purchased Power in the table above includes about $10.4 million in 2003 and $10.9 million in 2002 related to the purchase of power from the Company, under Connecticut Valley's long-term contract with the Company. These amounts are included in Operating Revenue on the Consolidated Statements of Income. Accounts Receivable from Connecticut Valley were of a nominal amount in 2004 and $1.8 million in 2003.

The major classes of assets and liabilities reported as discontinued operations on the Consolidated Balance Sheets are as follows (in thousands):

	December 31	
	2004	2003
Assets		
Net utility plant	**$ -**	$9,251
Other current assets	**-**	41
Total assets of discontinued operations	**$ -**	$9,292
Liabilities		
Accounts payable	**$ -**	$1,749
Short-term debt (a)	**-**	3,750
Total liabilities of discontinued operations	**$ -**	$5,499

(a) Related to an inter-company Note that was paid on January 1, 2004.

NOTE 5 – RECONCILIATION OF NET INCOME AND AVERAGE SHARES OF COMMON STOCK

Reconciliation of net income to net income available for common stock and average common shares outstanding basic to diluted follows ($ in thousands):

	December 31		
	2004	2003	2002
Income from continuing operations	**$11,415**	$18,355	$18,224
Income from discontinued operations, net of tax	**12,340**	1,446	1,543
Income before preferred stock dividends	**23,755**	19,801	19,767
Preferred stock dividend requirements	**368**	1,198	1,528
Income available for common stock	**$23,387**	$18,603	$18,239
Average shares of common stock outstanding – basic	**12,118,048**	11,878,255	11,660,369
Dilutive effect of stock options	**143,646**	124,791	110,614
Dilutive effect of restricted stock	**5,892**	5,892	17,870
Dilutive effect of performance plan shares	**33,601**	118,055	153,969
Average shares of common stock outstanding – diluted	**12,301,187**	12,126,993	11,942,822

Antidilutive Shares: At December 31, 2004 and 2003, all outstanding stock options were included in the computation of diluted shares because the exercise prices were lower than the average market price of the common shares. At December 31, 2002, options to purchase 129,400 shares of common stock at an average exercise price of $19.41 per share were outstanding but not included in the computation of diluted shares because the exercise prices were less than the average market price for the period ending December 31, 2002. See Note 9 – Stock Award Plans.

NOTE 6 – PREFERRED STOCK

The Company's preferred and preference stock consisted of the following (in thousands):

	2004	2003
Cumulative Preferred and Preference Stock		
Preferred stock, $100 par value, authorized 500,000 shares		
Outstanding:		
Non-redeemable		
4.15% Series; 37,856 shares	**$3,786**	$3,786
4.65% Series; 10,000 shares	**1,000**	1,000
4.75% Series; 17,682 shares	**1,768**	1,768
5.375% Series; 15,000 shares	**1,500**	1,500
Redeemable		
8.30% Series; 80,000 shares	**8,000**	10,000
Preferred stock, $25 par value, authorized 1,000,000 shares		
Outstanding – none	**-**	-
Preference stock, $1 par value, authorized 1,000,000 shares		
Outstanding – none	**-**	-
	16,054	18,054
Less current portion	**2,000**	2,000
Total cumulative preferred and preference stock	**$14,054**	$16,054

The Company's non-redeemable preferred stock and its mandatorily redeemable preferred stock are part of one class of Preferred Stock, $100 Par Value, and are of equal rank. Each series is entitled to a liquidation preference, over the holders of common stock, equal to Par Value, plus accrued and unpaid dividends, and a premium if liquidation is voluntary. In general, there are no "deemed" liquidation events. Holders of the Preferred Stock have no voting rights, except as required by Vermont law, and except that if accrued dividends on any shares of Preferred Stock have not been paid for more than two full quarters, each share will have the same voting power as Common Stock, and if accrued dividends have not been paid for four or more full quarters, the holders of the Preferred Stock have the right to elect a majority of the Company's Board of Directors.

All shares of all series of Preferred Stock are currently subject to redemption and retirement at the option of the Company upon vote of at least three-quarters of the Company's Board of Directors in accordance with the specific terms for each series and upon payment of the par value, accrued dividends and a premium to which each would be entitled in the event of voluntary liquidation, dissolution or winding up of the affairs of the Company.

The 8.3 percent Series Preferred Stock is redeemable at par through a mandatory sinking fund in the amount of $1 million per annum and, at its option, the Company may redeem at par an additional non-cumulative $1 million per annum. In the fourth quarter of 2004, the Company recorded $2 million in Restricted Cash related to a December 31, 2004 payment to the Transfer Agent for its $1 million mandatory sinking fund payment for 2005 and a $1 million optional payment. The payment to the Preferred Shareholders was made effective January 1, 2005. In the fourth quarter of 2003, the Company paid its $1 million mandatory sinking fund payment for 2004 and a $1 million optional payment.

The Company implemented the income statement impacts of SFAS No. 150 in 2004. This statement requires, among other things, that dividends associated with mandatory redeemable preferred stock be reported as interest expense. In 2004, the Company reclassified about $0.7 million of dividends on its mandatorily redeemable preferred stock from Preferred Stock Dividend Requirements to Interest Expense on the Consolidated Statement of Income.

NOTE 7 – LONG-TERM DEBT AND SINKING FUND REQUIREMENTS

The Company's long-term debt consisted of the following (in thousands):

	2004	2003
First Mortgage Bonds:		
6.27%, Series NN, due 2008	**$3,000**	$3,000
5.00%, Series SS, due 2011	**20,000**	-
5.72%, Series TT, due 2019	**55,000**	-
6.90%, Series OO, due 2023	**17,500**	17,500
8.91%, Series JJ, due 2031	**15,000**	15,000
Second Mortgage Bonds:		
8.125%, due 2004	**-**	75,000
New Hampshire Industrial Development Authority Bonds		
3.75%, due 2009	**5,450**	5,450
Vermont Industrial Development Authority Bonds		
Variable, due 2013 (1.8% at December 31, 2004)	**5,800**	5,800
Connecticut Development Authority Bonds		
Variable, due 2015 (1.9% at December 31, 2004)	**5,000**	5,000
Other, various	**-**	2,657
	126,750	129,407
Less current portion	**-**	2,657
Total long-term debt	**$126,750**	$126,750

Utility During the second quarter of 2004, the Company received regulatory approvals and waivers needed to issue First Mortgage Bonds to refinance and replace the $75 million Second Mortgage Bonds at a rate of 8.125 percent that matured on August 1, 2004. On May 28, 2004, the Company priced such First Mortgage Bonds. Pursuant to such pricing, on July 30, 2004, the Company issued $20 million of 5 percent First Mortgage Bonds, due in 2011, and $55 million of 5.72 percent First Mortgage Bonds, due in 2019. The proceeds were used to repay the $75 million Second Mortgage Bonds. Substantially all of the Company's utility property and plant is subject to liens under the First Mortgage Bonds. No sinking fund payments are due on long-term debt for 2005 through 2007.

The Company's First Mortgage Bonds are callable at its option at any time upon payment of a make-whole premium, calculated as the excess of the present value of the remaining scheduled payments to bondholders, discounted at a rate that is 0.5 percent higher than the comparable U. S. Treasury Bond yield, over the early redemption amount.

The Company's Connecticut Development Authority Bonds and Vermont Industrial Development Authority Bonds are callable at par as follows: 1) at the option of the Company or bondholders on each monthly interest payment date; or 2) at the option of the bondholders on any business day. The Company's New Hampshire Industrial Development Authority Bonds are callable at the option of the Company or the bondholders only in special circumstances involving unenforceability of the indenture or a change in the usability of the project.

The Company's debt financing documents do not contain cross-default provisions to affiliates outside of the consolidated entity. Certain of the Company's debt financing documents contain cross-default provisions to its wholly owned subsidiaries, East Barnet, CV Realty and Custom Investment Corporation. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, inappropriate affiliate transactions or the levy of significant judgments or attachments against our property. Currently, the Company is not in default under any of its debt financing documents.

Letters of Credit The Company renewed $16.9 million of unsecured letters of credits, issued by one financial institution, to November 30, 2005. These letters of credit support three series of Industrial Development Revenue Bonds, totaling $16.3 million. At December 31, 2004 and 2003, there were no amounts outstanding under these letters of credit.

Covenants The Company's long-term debt indentures, letters of credit and Articles of Association contain financial and non-financial covenants. At December 31, 2004, the Company was in compliance with all covenants.

Dividend restrictions The First Mortgage Bond indenture and the Company's Articles of Association contain certain restrictions on the payment of cash dividends on capital stock. Under the most restrictive of such provisions, approximately $99 million of retained earnings were not subject to dividend restriction at December 31, 2004.

Non-Utility In January 2004, Catamount paid off $2.5 million on its term loan and in February 2004, Catamount notified the lender of its intent to terminate the credit facility. Effective May 16, 2004, the credit facility was officially terminated. Catamount's office building mortgage matured on April 15, 2004 and Catamount paid the outstanding balance in full.

NOTE 8 – FINANCIAL INSTRUMENTS AND INVESTMENT SECURITIES

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*
Preferred stock not subject to mandatory redemption	**$8,054**	**$6,144**	$8,054	$5,431
Preferred stock subject to mandatory redemption	**$8,000**	**$8,662**	$10,000	$12,618
Long-term debt:				
First mortgage bonds	**$110,500**	**$122,985**	$35,500	$41,513
Second mortgage bonds	**-**	**-**	$75,000	$77,325
Other long-term debt	**$16,250**	**$16,180**	$18,907	$19,411

* Fair values are reported to meet disclosure requirements and do not necessarily represent the amounts at which obligations would be settled.

Cash, Receivables and Payables The carrying amounts of cash and cash equivalents, restricted cash, receivables and payables approximate fair value because of the short maturity of those instruments.

Preferred stock and long-term debt The fair value of the Company's fixed rate securities is estimated based on quoted market prices for the same or similar issues or on current rates offered to the Company for the same remaining maturation. Monthly adjustable-rate securities are assumed to have a fair value equal to their carrying value.

Derivatives The estimated fair value of derivatives related to power contracts is based on over-the-counter quotations or broker quotes at the end of the reporting period, with the exception of one long-term power contract that is valued using a binomial tree model, and quoted market data when available, along with appropriate valuation methodologies. These derivative instruments are recorded at fair value in the Consolidated Balance Sheets.

Life Insurance Investments Life insurance investments are held in a Rabbi Trust for the benefit of executive retirement plans. These life insurance policies are recorded at the net cash surrender value or fair value on the Consolidated Balance Sheets. At December 31, 2004 and 2003, these life insurance investments had a fair value of $6.0 million and $5.2 million, respectively, equal to their carrying value.

Available-for-sale securities In the first quarter of 2004, the Company invested proceeds received from the Connecticut Valley sale and other cash on hand in available-for-sale securities with various maturities. These available-for-sale securities are subject to SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities* ("SFAS No. 115"), and are recorded at fair value. Investments with maturities of one year or less are included in Current Assets, while those with maturities greater than one year are included in Investments and Other Assets on the Consolidated Balance Sheets. Realized gains and losses are included in interest income, and unrealized gains and losses are included in other comprehensive income. At December 31, 2004, unrealized losses on available-for-sale securities, both on an individual and aggregate basis, are minor when compared to the original costs. Therefore, such unrealized losses are considered temporary. Also, such losses have been in a continuous loss position for less than 12 months at December 31, 2004.

The Company's available-for-sale securities include auction rate securities, which are also subject to SFAS No. 115. Auction rate securities are highly liquid, variable-rate debt securities that are included in Current Assets on the Consolidated Balance Sheets. While the underlying security has a perpetual maturity, the interest rate is reset through 'Dutch' auctions that are typically held every 7, 28 or 35 days, creating a short-term instrument. Interest is paid at the end of each auction period; therefore there are no unrealized losses or unrealized gains associated with these securities.

Information regarding available-for-sale securities as of December 31, 2004 follows (in thousands):

	Due in one year or less				Due after one year through five years			
Security Types	Original Cost	Fair Value	Unrealized Losses	Unrealized Gains	Original Cost	Fair Value	Unrealized Losses	Unrealized Gains
US Government Obligations	$2,006	$2,002	$4	-	-	-	-	-
US Government Agencies	8,060	8,010	50	-	$15,492	$15,336	$156	-
Corporate Bonds	4,442	4,425	17	-	6,657	6,582	75	-
Auction Rate Securities	4,825	4,825	-	-	-	-	-	-
Total	**$19,333**	**$19,262**	**$71**	**-**	**$22,149**	**$21,918**	**$231**	**-**

At December 31, 2003, available-for-sale securities included auction rate securities of $34.4 million.

Millstone Decommissioning Trust Fund The Company has decommissioning trust fund investments related to its joint-ownership interest in Millstone Unit #3. The decommissioning trust fund was established pursuant to various federal and state guidelines. Among other requirements, the fund is required to be managed by an independent and prudent fund manager. Any gains or losses, realized and unrealized, are expected to be refunded to or collected from ratepayers, respectively. For that reason, the fair value is adjusted by realized and unrealized gains and losses, with a corresponding decommissioning liability recorded as Asset Retirement Obligations on the Consolidated Balance Sheets. Additionally, any appreciation on the trust fund investments is used to offset the related decommissioning liability.

These investments are subject to the requirements of SFAS No. 115, and are recorded at fair value in Investments and Other Assets on the Consolidated Balance Sheets. The unrealized losses on the decommissioning trust fund are minor when compared to their original cost; therefore, they are considered temporary. At December 31, 2004, losses on equity securities have been in a continuous loss position for less than 12 months.

The fair value of these investments is summarized below (in thousands):

	2004				2003			
	Original Cost	Fair Value	Unrealized Losses	Unrealized Gains	Original Cost	Fair Value	Unrealized Losses	Unrealized Gains
Equity Securities	$2,464	$3,537	$1,093	$20	$2,381	$3,175	$794	-
Debt Securities	1,103	1,144	43	2	1,052	1,105	55	$2
Cash and other	40	40	-	-	60	60	-	-
Fair Value	$3,607	$4,721	$1,136	$22	$3,493	$4,340	$849	$2

Information related to the fair value of debt securities at December 31, 2004 follows (in thousands):

	Fair value of debt securities at contractual maturity dates				
	Less than 1 year	1 year to 5 years	5 years to 10 years	After 10 years	Total
Debt Securities	$3	$345	$305	$491	$1,144

NOTE 9 - STOCK AWARD PLANS

The Company has awarded stock options to key employees and non-employee directors under the plans shown in the table below. The 2002 Long-Term Incentive Plan also authorizes the granting of stock appreciation rights, restricted shares and performance shares. Options are granted at the fair market value of the common shares on the date of grant. The maximum term of an option may not exceed five years for non-employee directors and 10 years for key employees. Summarized information regarding stock award plans at December 31, 2004 follows:

Plan	Authorized	Stock options outstanding	Available for future grant
1988 Stock Option Plan - Key Employees	334,375	18,000	-
1997 Stock Option Plan - Key Employees	350,000	166,870	17,330
1997 Restricted Stock Plan	70,000	-	-
1998 Stock Option Plan - Non-employee Directors	112,500	43,425	-
2000 Stock Option Plan - Key Employees	350,000	246,370	1,530
2002 Long-Term Incentive Plan	350,000	121,985	175,989
Total	**1,566,875**	**596,650**	**194,849**

Stock option activity during the past three years was as follows:

	2004	2003	2002
Options outstanding at January 1	**498,750**	571,285	494,585
Exercised	**(48,650)**	(164,625)	(28,700)
Granted	**146,550**	111,865	109,900
Expired/canceled	**-**	(19,775)	(4,500)
Options outstanding at December 31	**596,650**	498,750	571,285

Summarized information regarding stock options outstanding and exercisable at December 31, 2004:

		Weighted Average	
Range of Exercise Prices	Number Options	Remaining Contractual Life (Years)	Exercise Price
$10.4495 - $12.2578	127,160	4.0	$10.7637
$12.2579 - $14.0663	18,000	1.0	$13.8542
$14.0664 - $15.8747	59,500	3.3	$14.6250
$15.8748 - $17.6831	164,115	7.1	$17.0062
$17.6832 - $19.4916	83,825	6.1	$19.1012
$19.4917 - $21.3000	144,050	9.3	$20.1665
	596,650		

The stock options granted during 2004 had a weighted-average grant date fair value of $2.82, compared to $2.25 in 2003 and $3.57 in 2002. The fair value was estimated using the Black-Scholes model for 2004 and 2003 and the binomial model for 2002, with the weighted-average assumptions shown in the table below. The Company changed its option-pricing model in 2003 due to the added ease of calculation of the Black-Scholes model. The change in methodology did not materially alter the results of the computation.

	2004	2003	2002
Volatility	**.2551**	.2204	.2548
Risk-free rate of return	**3.55%**	3.12%	5.50%
Dividend yield	**5.74%**	5.74%	6.61%
Expected life (years)	**5.81**	5.74	7.14

Also see Note 5 – Reconciliation of Net Income and Average Shares of Common Stock for information regarding shares with an anti-dilutive affect.

Restricted Stock Plans The Company has restricted stock plans in which common stock is granted to its directors and certain executive officers, key employees and non-employee directors. Recipients are not required to provide consideration to the Company under these plans, other than rendering service, and have the right to vote the shares and to receive dividends under the plans. The Company accounts for these stock plans under APB 25.

Under the Company's 1997 Restricted Stock Plan ("Restricted Plan"), the total market value of the shares, at grant date, is treated as deferred compensation and charged to expense over the applicable vesting period. Interim estimates of compensation expense are recorded at the end of each reporting period based on a combination of the then-fair market value of the stock and the extent or degree of compliance with the performance criteria. Restricted Plan stock expense was $135,382 in 2004, $136,538 in 2003, and $134,229 in 2002. Restricted shares issued during the past three years, excluding shares issued for the performance plans described below, were as follows:

	2004	2003	2002
Granted	**4,987**	5,017	11,642
Deferred	**(474)**	(375)	(632)
Issued	**4,513**	(4,642)	(11,010)
Average market value per issued share	**$20.98**	$20.42	$17.00
Unvested at December 31	**5,892**	5,892	17,870
Average market value per unvested share	**$17.47**	$17.47	$13.04

As part of the Company's Long-Term Incentive Plan, restricted performance shares of common stock have been awarded to executive officers at the start of each year under the Performance Share Plans ("Performance Plan") beginning with the 1999 three-year performance cycle. These awards vary from zero to two times the number of conditionally granted shares based on the Company achieving certain financial goals over three-year performance cycles. The total market value of the shares is treated as deferred compensation and charged to expense on a quarterly basis over the respective performance cycles based on changes in market value, achievement of financial goals and changes in employment. Performance Plan stock compensation charged to expense was $164,832 in 2004, $834,469 in 2003 and $1,009,896 in 2002. Performance Plan activity during the past three years was as follows:

	2004	2003	2002
Performance awards allocated at January 1 (a)	**118,055**	153,969	134,723
Shares issued (b)	**(28,329)**	(15,547)	(17,044)
Shares withheld for taxes	**(15,274)**	(9,383)	(7,967)
Shares deferred	**(7,422)**	(14,382)	-
Award changes based on quarterly performance	**(33,429)**	17,398	46,657
Awards forfeited	**-**	(14,000)	(2,400)
Performance awards allocated at December 31 (a)	**33,601**	118,055	153,969
Average market value per issued share	**$23.90**	$18.07	$16.35

(a) Represents all awards eligible for future payout on active three-year performance cycles, based on achievement of financial goals at period end.
(b) Represents shares issued at end of three-year performance cycle, net of shares withheld for taxes.

NOTE 10 - PENSION AND POSTRETIREMENT BENEFITS

The Company has a qualified, non-contributory, defined-benefit, trusteed, pension plan ("Pension Plan") covering all employees (union and non-union). Under the terms of the Pension Plan, employees are vested after completing five years of service, and can retire when they are at least age 55 with a minimum of 10 years of service. They are eligible to receive monthly benefits or a lump sum amount. The Company's funding policy is to contribute at least a statutory minimum to a trust. The Company is not required by its union contract to contribute to multi-employer plans.

On January 1, 2002, the Pension Plan was amended to include enhanced early retirement reduction factors and death benefits for beneficiaries of deceased active participants. Assumed rates of retirement were updated to reflect expected experience. The Company also adopted the GAR 94 mortality table and a heavier withdrawal assumption, as well as the GAR 94 lump sum basis required by IRS Revenue Ruling 2001-62.

The Company also sponsors a defined-benefit postretirement medical plan that covers all employees who retire with 10 or more years of service after age 45 and are at least age 55. The Company funds this obligation through a Voluntary Employees' Benefit Association and 401(h) Subaccount in its Pension Plan.

The Company records pension and other postretirement benefit costs in accordance with SFAS No. 87, Employers' Accounting for Pensions, and SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. Also, the Company follows SFAS No. 132, Employers' Disclosures about Pensions and other Postretirement Benefits.

Benefit Obligation and Plan Assets

The changes in benefit obligation and Plan assets were as follows (in thousands):

	At December 31			
	Pension Benefits		Postretirement Benefits	
Change in Benefit Obligation	2004	2003	2004	2003
Benefit obligation at beginning of measurement date	**$91,505**	$83,498	**$26,265**	$20,512
Service cost	**3,021**	2,745	**539**	421
Interest cost	**5,551**	5,483	**1,554**	1,309
Amendments	**89**	-	**-**	-
Actuarial loss (gain)	**1,824**	4,194	**(1,947)**	6,071
Benefits paid	**(5,640)**	(4,415)	**(1,920)**	(2,048)
Projected obligation as of measurement date (September 30)	**$96,350**	$91,505	**$24,491**	$26,265
Accumulated obligation as of measurement date (September 30)	**$78,708**	$75,379	**-**	-

The reduction in the Company's accumulated postretirement benefit obligation ("APBO") due to the impact of the Medicare Part D subsidy is $1.8 million.

	Pension Benefits		Postretirement Benefits	
Change in Plan Assets	2004	2003	2004	2003
Fair value of plan assets at beginning of measurement date	**$59,304**	$54,291	**$4,230**	$4,026
Actual return on plan assets	**6,722**	9,428	**4**	28
Employer contributions *	**1,127**	-	**2,329**	2,224
Benefits paid *	**(5,640)**	(4,415)	**(1,920)**	(2,048)
Fair value of assets as of measurement date (September 30)	**$61,513**	$59,304	**$4,643**	$4,230

* Postretirement benefits include benefits paid from employer assets.

Benefit Obligation Assumptions Weighted-average assumptions used to determine benefit obligations at measurement date (September 30) are shown in the table that follows. The selection methodology used in determining discount rates includes portfolios of "Aa" bonds; all are United States issues and non-callable (or callable with make-whole features) and are at least $50 million. As of September 30, 2004, the discount rate remained at 6 percent. The 2004 weighted-average assumptions for pension and postretirement benefits were used in determining the Company's related liabilities at December 31, 2004. Similarly, the 2003 weighted-average assumptions were used in determining liabilities at December 31, 2003.

	Pension Benefits		Postretirement Benefits	
	2004	2003	**2004**	2003
Discount rates	**6.00%**	6.00%	**6.00%**	6.00%
Rate of increase in future compensation levels	**3.75%**	3.75%	**3.75%**	3.75%

For measurement purposes, an 11 percent and 10.5 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for fiscal 2005, for pre-65 and post-65 claims costs, respectively. The rate is assumed to decrease 1 percent in each of the subsequent years until the ultimate trend of 6 percent and 5.5 percent, respectively, is reached.

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect:

	1-Percentage Point Increase	1-Percentage Point Decrease
Effect on postretirement benefit obligation as of September 30, 2004	$1,714,369	$(1,469,459)
Effect on total service and interest costs components	$170,308	$(141,978)

Asset Allocation

The asset allocations at the measurement date for 2004 and 2003, and the target allocation for 2005, by asset category, are as follows (in thousands):

	Pension Plan			Postretirement Benefits		
	2005 Target	2004	2003	2005 Target	2004	2003
Equity securities	67.0%	66.7%	66.8%	67.0%	-	-
Debt securities	33.0	33.3	33.2	33.0	39.2%	91.6%
Other	-	-	-	-	60.8	8.4
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Investment Strategy The Company's pension investment policy seeks to achieve sufficient growth to enable the Pension Plan to meet its future benefit obligations to participants, to maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 67 percent of plan assets be invested in equity securities and 33 percent of plan assets be invested in debt securities.

The Company's postretirement investment policy seeks to achieve sufficient funding levels to meet future benefit obligations to participants and minimize near-term cost volatility. During 2004, the plan assets were invested in debt securities and cash equivalents. The Company plans to invest 67 percent of plan assets in equity securities during 2005.

Fair Value The fair value of Pension Plan assets was $61,513,357 at the measurement date for 2004 and $59,304,361 at the measurement date for 2003, while the expected long-term rate of return was 8.25 percent in 2004 and 8.25 percent in 2003.

The fair value of postretirement benefit assets was $4,643,339 at the measurement date for 2004 and $4,229,782 at the measurement date for 2003, while the expected long-term rate of return was 8.25 percent in 2004 and 8.25 percent in 2003.

Funded Status

The Plans' funded status was as follows (in thousands):

	Pension Plan		Postretirement Plan	
Reconciliation of funded status	**2004**	2003	**2004**	2003
Fair value of assets	**$61,513**	$59,304	**$4,643**	$4,230
Benefit obligation	**(96,350)**	(91,505)	**(24,491)**	(26,265)
Company contributions between measurement and year-end dates	**-**	-	**792**	573
Funded Status	**(34,837)**	(32,201)	**(19,056)**	(21,462)
Unrecognized net actuarial loss	**16,421**	15,695	**13,234**	16,135
Unrecognized prior service cost	**3,785**	4,089	**2**	2
Unrecognized net transition (asset) obligation	**-**	(145)	**2,047**	2,303
Accrued benefit cost	**$(14,631)**	$(12,562)	**$(3,773)**	$(3,022)

The amounts recognized in the Company's Consolidated Balance Sheets consisted of (in thousands):

	Pension Plan		Postretirement Plan	
	2004	2003	**2004**	2003
Accrued benefit liability	**$(14,631)**	$(12,562)	**$(3,773)**	$(3,022)
Additional minimum liability	**(2,563)**	(3,513)	**-**	-
Intangible asset	**2,563**	3,513	**-**	-
Net amount recognized	**$(14,631)**	$(12,562)	**$(3,773)**	$(3,022)

Net Periodic Benefit Costs Components of net periodic benefit costs were as follows (in thousands):

	Pension Benefits			Postretirement Benefits		
	2004	2003	2002	**2004**	2003	2002
Net benefit costs include the following components						
Service cost	**$3,021**	$2,745	$2,337	**$539**	$420	$331
Interest cost	**5,551**	5,483	5,354	**1,554**	1,309	1,153
Expected return on plan assets	**(5,624)**	(5,956)	(6,493)	**(432)**	(308)	(243)
Amortization of prior service cost	**394**	394	295	**1**	-	-
Recognized net actuarial loss (gain)	**-**	-	(594)	**1,381**	843	416
Amortization of transition (asset) obligation	**(146)**	(146)	(146)	**256**	256	256
Supplemental adjustment for amortization of FAS 71						
Regulatory asset (1997 VERP)	**-**	-	25	**-**	-	25
Accelerated amortization of FAS 71						
Regulatory asset (1997 VERP)	**-**	-	-	**-**	-	-
Net periodic benefit cost	**$3,196**	$2,520	778	**3,299**	2,520	1,938
Less amount allocated to other accounts	**515**	423	100	**531**	423	253
Net benefit costs expensed	**$2,681**	$2,097	$678	**$2,768**	$2,097	$1,685

Benefit Costs Assumptions Weighted-average assumptions used to determine net periodic costs at measurement date (September 30) are shown in the table below. The weighted-average assumptions shown for 2004, which were set at September 30, 2003, were used in determining 2004 expense. Likewise, the 2003 and 2002 weighted-average assumptions were used in determining 2003 and 2002 expense, respectively.

	Pension Benefits			Postretirement Benefits		
	2004	2003	2002	**2004**	2003	2002
Weighted-average discount rates	**6.00%**	6.50%	7.25%	**6.00%**	6.50%	7.25%
Expected long-term return on assets	**8.25%**	8.25%	8.50%	**8.25%**	8.25%	8.50%
Rate of increase in future compensation levels	**3.75%**	4.00%	4.50%	**3.75%**	4.00%	4.50%

Expected Rate of Return on Plan Assets

The Company expects an annual long-term return for the pension asset portfolio of 8.25 percent, based on a representative allocation within the target asset allocation described above. In formulating this assumed rate of return, the Company considered historical returns by asset category and expectations for future returns by asset category based, in part, on simulated capital market performance over the next 10 years.

Based on the postretirement investment policy described above, the Company expects an annual long-term return for the postretirement portfolio of 8.25 percent. In formulating this assumed long-term rate of return, asset categories and expectations for future returns by asset category were considered.

Pension and postretirement benefit expenses for 2004 were based on an expected long-term return on assets rate of 8.25 percent. The same percentage will be used to determine the 2005 expenses.

Pension Equity Adjustment Risk

Certain negative scenarios and unfavorable market conditions (asset returns are lower than expected, reductions in discount rates, and liability experience losses) may cause the Pension Plan's accumulated benefit obligation ("ABO") to exceed the fair value of Pension Plan assets as of the measurement date and would result in an unfunded minimum liability. If that occurs and the minimum liability exceeds the accrued benefit cost, an additional minimum pension liability may be required to be recorded, net of tax, as a non-cash charge to other comprehensive income, included in common stock equity on the balance sheet. The ABO represents the present value of benefits earned without considering future salary increases. The Company did not have a reduction in equity for the qualified Pension Plan for the year ended December 31, 2004 since the intangible asset, representing prior service costs and transition obligation, offset the additional minimum pension liability. Based on actual asset returns through December 31, 2004 and assuming all assumptions are met for the remainder of the measurement period through September 30, 2005, the Company does not anticipate a significant reduction in equity for the year ending December 31, 2005. Reductions in the discount rate of 25 basis points could result in an after-tax non-cash charge to other comprehensive income of about $1.1 million.

The Pension Plan currently meets the minimum funding requirements of the Employee Retirement Income Security Act of 1974. In 2004, the Company was required to contribute $1.1 million to the Pension Plan and will have funding requirements of $3.4 million in 2005.

Expected Cash Flows

The table below reflects the total benefits expected to be paid from the external Pension Plan trust fund or from the Company's assets, including both the Company's share of the pension and postretirement benefit costs and the participants' share of the postretirement benefit cost funded by participant contributions. Of the benefits expected to be paid in 2005, about $5.1 million will be paid from the Pension Plan trust fund and about $1.9 million related to postretirement benefits will be paid from the Company's assets.

Expected contributions reflect amounts expected to be contributed to funded plans. Information about the expected cash flows for the Pension Plan and postretirement benefit plans is as follows (in millions):

	Pension Benefits	Postretirement Benefits
Employer Contributions		
2005 (expected) to fund plan trusts & benefits *	$3.4	$1.1
Expected Benefit Payments		
2005	$5.1	$1.9
2006	5.0	1.8
2007	5.6	1.9
2008	6.7	1.9
2009	7.8	1.9
2010 - 2014	48.3	9.9

* Excludes expected benefit payments paid from employer assets for postretirement benefits.

The expected Medicare Part D subsidy present in the expected gross postretirement benefit payments is as follows (in millions):

Reduction in Expected Postretirement Benefit Payments	
2005	-
2006	$0.2
2007	0.2
2008	0.2
2009	0.2
2010 - 2014	0.8

The above amounts are for the calendar year, even though September 30 is the measurement date.

Other

Long-term Disability The Company provides post-employment long-term disability benefits. The accumulated year-end post-employment benefit obligations of $1.6 million in 2004 and $1.3 million in 2003 are reflected in the Company's Consolidated Balance Sheets as liabilities. The pre-tax post-employment benefit costs charged to expense, including insurance premiums, were $441,000 in 2004, $270,000 in 2003 and $225,000 in 2002.

401(k) Savings Plan The Company maintains a 401(k) Savings Plan for substantially all employees. This savings plan provides for employee pre-tax and post-tax contributions up to specified limits. The Company matches employee pre-tax contributions up to 4 percent of eligible compensation after one year of service. Eligible employees are at all times 100 percent vested in their pre-tax and post-tax contribution account and in their matching employer contribution. The Company's matching contributions amounted to $1.2 million in 2004 and $1.1 million annually in 2003 and 2002.

Other Benefits The Company also provides an Officers' Supplemental Retirement Plan ("SERP") that is designed to supplement the retirement benefits available through the Company's qualified Pension Plan to certain of the Company's executive officers. The minimum SERP liability is measured at year-end. To the extent that the additional liability exceeds the intangible asset, other comprehensive income, net of tax is recorded. The accumulated year-end SERP benefit obligation was $3.4 million in 2004 and $3.3 million in 2003 and is reflected in the Consolidated Balance Sheets as a liability. The accumulated benefit obligation included $0.1 million of other comprehensive income in 2004 and the pre-tax SERP benefit costs charged to expense totaled $409,000 in 2004, $446,000 in 2003 and $375,000 in 2002. Benefits are funded by the Company through a Rabbi Trust. The year-end balance included in Investments and Other Assets was $6.0 million in 2004 and $5.2 million in 2003.

NOTE 11 - INCOME TAXES

The Company's income tax provision (benefit) from continuing operations consisted of the following (in thousands):

	For the years ended December 31		
	2004	2003	2002
Federal:			
Current	**$1,757**	$10,040	$8,583
Deferred	**(1,085)**	(3,627)	438
Investment tax credits, net	**(379)**	(379)	(379)
	293	6,034	8,642
State:			
Current	**1,348**	3,112	2,439
Deferred	**(1,278)**	(491)	10
	70	2,621	2,449
Total federal and state income taxes	**$363**	$8,655	$11,091
Federal and state income taxes charged to:			
Operating expenses	**$1,056**	$10,125	$11,009
Other income	**(693)**	(1,470)	82
	$363	$8,655	$11,091

The reconciliation between income taxes computed by applying the U.S. federal statutory rate and the reported income tax provision (benefit) follows (in thousands):

	For the years ended December 31		
	2004	2003	2002
Income before income tax	**$11,778**	$27,010	$29,316
Federal statutory rate	**35%**	35%	35%
Federal statutory tax expense	**4,122**	9,454	10,261
Increases (reductions) in taxes resulting from:			
Dividend received deduction	**(340)**	(499)	(1,086)
State income taxes net of federal tax benefit	**948**	1,704	1,592
Investment credit amortization	**(379)**	(379)	(379)
Loss on sale of equity interests	**(3,222)**	-	-
Equity method of accounting adjustment	**-**	1,949	-
Change in valuation allowance	**112**	(3,430)	257
AFUDC equity	**273**	216	214
Life insurance	**(345)**	(364)	318
Income tax refunds	**(930)**	-	-
Change in estimate for tax contingencies	**(322)**	-	-
Other	**446**	4	(86)
Total income tax expense provided	**$363**	$8,655	$11,091
Effective combined federal and state income tax rate	**3.1%**	32%	37.8%

For 2004, Catamount completed the sale of its Glenns Ferry, Rupert and Fibrothetford equity interests and, as a result, Catamount recorded an additional $3.2 million of income tax benefits.

During 2004, the Company received three income tax refunds totaling $0.9 million (exclusive of interest). One refund related to an appeal of an overpayment from a prior federal income tax audit for the tax years 1982 through 1984. The proceeds from the settlement included a federal income tax refund of $0.5 million. The other two refunds related to an appeal of federal and state income tax overpayments for 2000. The proceeds from the settlements included a federal income tax refund of $0.3 million and a state refund of $0.1 million.

The Company decreased its estimate for tax contingencies by $0.3 million due to a reduction in potential tax liabilities.

Valuation Allowances SFAS No. 109 prohibits the recognition of all or a portion of deferred income tax benefits if it is more likely than not that the deferred tax asset will not be realized. For the periods ended 2004 and 2003, the valuation allowances recorded were $0.9 million and $0.8 million respectively for certain losses related to Catamount's foreign investments. Management added $0.1 million to the valuation allowances for certain foreign losses incurred in 2004 related to Catamount's foreign investments after it determined that it is more likely than not that a current or future income tax benefit would not be realized.

For 2003, the valuation allowances were decreased by $3.4 million. Management determined that the Connecticut Valley sale agreement was more likely than not to occur, which afforded the Company the opportunity to realize capital gains on the sale. The capital gains treatment allowed for a $2.3 million reduction of certain tax valuation allowances at Catamount. The valuation allowances were also reduced by $1.9 million due to the reclassification of an equity method of accounting adjustment related to the financial statements from one of Catamount's foreign projects. The valuation allowances were increased by $0.8 million for certain foreign losses related to Catamount's foreign investments. Management determined that it was more likely than not that a current or future income tax benefit would not be realized.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2004 and 2003 are presented below (in thousands):

	December 31	
	2004	2003
Deferred tax assets		
Equity investments	$2,050	$3,958
Accruals and other reserves not currently deductible	5,172	5,703
Deferred compensation and pension	6,723	7,326
Environmental costs accrual	2,466	2,973
Millstone decommissioning costs	2,175	1,794
Contributions in aid of construction	1,842	1,840
Revenue deferral - Vermont utility earnings	2,986	1,331
SFAS No. 5 loss accrual	5,348	-
Valuation allowance	(919)	(811)
Total deferred tax assets	27,843	24,114
Deferred tax liabilities		
Property, plant and equipment	41,445	41,848
Equity investments	6,024	7,258
Net regulatory asset	1,621	2,379
Vermont Yankee fuel rod maintenance	1,383	1,282
Vermont Yankee sale	5,481	5,292
Decommissioning costs	2,788	1,453
Other	1,480	1,315
Total deferred tax liabilities	60,222	60,827
Net deferred tax liability	$32,379	$36,713

On June 7, 2004, the State of Vermont enacted legislation that reduced the state income tax rate from 9.75 percent to 8.9 percent effective January 1, 2006, and from 8.9 percent to 8.5 percent effective January 1, 2007. Deferred tax assets and liabilities were adjusted in 2004 to reflect the enacted income tax rate change. This rate change reduced regulatory tax assets by about $1.4 million, and increased income tax expense by about $0.2 million. The increase in tax expense was primarily caused by a reduction in non-operating deferred tax assets. The decrease in regulatory assets was primarily caused by a decrease in operating deferred tax liabilities.

A deferred tax asset attributable to a SFAS No. 5 loss accrual was recorded in 2004 resulting in an ending balance of $5.3 million net of amortization. See Reserve for Loss on Power Contract in Note 1 – Summary of Significant Accounting Policies.

NOTE 12 - RETAIL RATES

The Company recognizes adequate and timely rate relief is required to maintain its financial strength, particularly since Vermont law does not allow power and fuel costs to be passed to consumers through fuel adjustment clauses. The Company will continue to review costs and request rate increases when warranted.

Vermont Retail Rates The Company's current retail rates are based on a June 26, 2001 PSB Order approving a settlement with the DPS, which included a 3.95 percent rate increase effective July 1, 2001. As part of the settlement, the Company also agreed to a $9 million write-off ($5.3 million after-tax) of regulatory assets and a rate freeze through January 1, 2003. The order also ended uncertainty over Hydro-Quebec cost recovery by providing full cost recovery, made the January 1, 1999 temporary rates permanent, allowed the Vermont utility a return on common equity of 11 percent for the year ending June 30, 2002 (capped through January 1, 2004) and created new service quality standards. Lastly, the rate order requires the Company to return up to $16 million to ratepayers if there is a merger, acquisition or asset sale that requires PSB approval.

In April 2003, the Company filed cost of service studies for rate years 2003 and 2004, in accordance with the PSB's approval of the Vermont Yankee sale. The purpose was to determine whether a rate decrease was warranted in either year as a result of the sale of the Vermont Yankee plant. In July 2003, the Company agreed to a Memorandum of Understanding ("MOU") with the DPS regarding that filing. The MOU concluded that: 1) a rate decrease was not warranted; 2) the Company would decrease its allowed return on common equity from 11 percent to 10.5 percent effective July 1, 2003; 3) any earnings over the allowed cap of 10.5 percent would be applied to reduce deferred charges on the balance sheet; 4) the Company would file a fully allocated cost of service plan and a proposed rate redesign; and 5) the Company agreed to work cooperatively with the DPS to develop and propose an alternative regulation plan.

Hearings on the MOU were conducted by the PSB in December 2003, and the PSB issued an Order on January 27, 2004 providing conditional approval for the MOU. It included the following significant modifications: 1) that the allowed return on common equity be reduced to 10.25 percent; 2) starting January 1, 2004 the Company would begin new amortizations of deferred charges on the balance sheet at December 31, 2003 of about $2.5 million annually; and 3) that the Company would file with the PSB a proposal to apply the $21 million payment it received in connection with the Connecticut Valley sale to write down deferred charges.

On February 3, 2004, the Company filed a Request for Reconsideration and Clarification, and in March 2004 participated in a workshop to review the filing. On April 7, 2004, the PSB denied the Company's request. While the PSB agreed to remove the third modification, absent the Company's acceptance of the remaining modifications, the PSB concluded that it would open a rate investigation. Consequently, the PSB issued an Order Opening Investigation and Notice of Prehearing Conference in Docket No. 6946 to investigate the Company's current rates.

On July 15, 2004, the Company filed a cost of service in the rate investigation that demonstrated a rate deficiency of 2.4 percent, and recommended that rates should not be decreased retroactively to April 1, 2004. Also on July 15, 2004, the Company filed its request with the PSB for a 5.01 percent rate increase, to be effective April 1, 2005, and requested that the two cases be consolidated. On September 8, 2004, the PSB consolidated the two cases and confirmed a schedule for proceedings through 2004, with a final order in March 2005.

On October 1, 2004, the DPS filed its testimony with the PSB related to the rate investigation and the request for a rate increase. The DPS's major findings and recommendations included: 1) a rate refund to ratepayers retroactive to April 1, 2004 of 4.65 percent or $12 million; and 2) a rate reduction of 5.93 percent or almost $16 million on an annual basis effective with service rendered April 1, 2005. On October 1, 2004, AARP, an intervener in the case, filed testimony that supported a rate increase of up to 3.5 percent effective April 1, 2005. Technical hearings with the PSB began in early November 2004. Hearings and filings continued through February 2005.

In filings with the PSB on February 11 and 16, 2005, the DPS suggested: 1) a rate refund or credit to the Company's ratepayers retroactive to April 1, 2004 of about 6 percent or $16 million; and 2) a rate reduction of about 7 percent or $19 million effective with service rendered April 1, 2005. While supporting the DPS position, AARP proposed the following modifications: 1) allow a 10 percent return on equity (the DPS recommended 8.75 percent); 2) amortize deferred debits over a six-year period (the DPS recommended a three-year period); and 3) exclude the costs associated with or resulting from the Connecticut Valley asset sale from the Company's cost of service.

On February 18, 2005, the PSB approved the Company's request for an Accounting Order that, among other things, allowed for deferral of certain 2004 utility earnings. The approved Accounting Order permitted the Company to record in other regulatory liabilities any earnings achieved by the utility in excess of the 11 percent return on equity. The earnings to be deferred were calculated by the same method the Company used for determining and reporting earnings for 2001, 2002 and 2003 under the mandated earnings cap of 11 percent per the July 2001 PSB-approved rate order. In 2004, utility earnings above the 11 percent return on equity amounted to $3.8 million pre-tax and the resulting regulatory liability will be accounted for as determined by the PSB in its final order. The issuance of the Accounting Order does not create any expectations, set any precedent, or in any other way impair the PSB's ability to rule on the contested issues in the rate case.

The DPS opposed the Company's request for an Accounting Order and expressed concern that PSB approval of the Accounting Order would create the perception that regulators supported the Company's proposed 11 percent return on equity and the method for calculating the earnings cap for the 2001 to 2003 period. The DPS suggested alternative methods to mitigate the financial impacts of a potential adverse decision. Those alternatives were not accepted by the PSB. However, the PSB's approval of the Accounting Order made clear that the 11 percent return on equity and the method for calculating overearnings for the period of 2001 to 2003 are in dispute in the rate proceedings and that the Accounting Order does not decide these issues.

The last PSB hearing was held on February 18 and the parties filed reply briefs on February 28, 2005. The Company's February 28, 2005 reply brief demonstrates that a reduction in the Company's rates for the period April 1, 2004 through March 31, 2005 would not be just or reasonable. Instead a modest increase (about 2.9 percent) in the Company's rates beginning April 1, 2005 is justified. The Company based its conclusion on the terms of the power cost settlement reached with the DPS and application of the $3.8 million deferred 2004 earnings to reduce deferred charges eligible for recovery in rates. Both of these items require approval by the PSB. A final decision from the PSB is expected on March 25, 2005. The Company cannot predict the outcome of the rate case at this time.

New Hampshire Retail Rates On January 1, 2004 Connecticut Valley completed the sale of substantially all of its plant assets and its franchise to PSNH. Prior to the sale, Connecticut Valley's retail rate tariffs were approved by the NHPUC, and contained a Fuel Adjustment Clause and a Purchased Power Cost Adjustment. Under these clauses, Connecticut Valley recovered its estimated annual costs for purchased energy and capacity; these estimates were reconciled annually when actual data was available.

NOTE 13 - COMMITMENTS AND CONTINGENCIES

Nuclear Investments The Company has a 2 percent equity ownership in Maine Yankee, 2 percent equity ownership in Connecticut Yankee and 3.5 percent equity ownership in Yankee Atomic, all of which are permanently shut down and are currently conducting decommissioning activities. The Company is responsible for paying its equity ownership percentage of decommissioning costs for all three plants. See Note 2 – Investments in Affiliates for additional information. The Company is also responsible for its 1.7303 joint-ownership percentage of decommissioning costs for Millstone Unit #3 as explained in Joint-ownership below.

Nuclear Insurance: The Price-Anderson Act ("Act") currently limits public liability from a single incident at a nuclear power plant to approximately $10 billion. This protection consists of two levels. The primary level provides liability insurance coverage of $300 million. If this amount is not sufficient to cover claims arising from an accident, the second level, referred to as secondary financial protection, applies. For the second level, each nuclear plant must pay a retrospective premium equal to its proportionate share of the excess loss, up to a maximum of $100.6 million per reactor per incident, limited to a maximum annual assessment of $10 million. The maximum assessment is adjusted at least every five years to reflect inflation. The Act has been renewed since it was first enacted in 1957, and expired in August 2002. Amendments to the Act were included in the Energy Policy Act of 2003, which was not passed, but renewal of the law is still being considered as part of comprehensive energy legislation. The liability coverage purchased by existing commercial nuclear power plants under the Act is not affected by the expiration date. Currently, based on its joint-ownership interest in Millstone Unit #3, the Company could become liable for about $0.2 million of such maximum assessment per incident per year. The Maine Yankee, Connecticut Yankee and Yankee Atomic plants have received exemptions from participating in the secondary financial protection program under the Act.

Hydro-Quebec The Company is purchasing varying amounts of power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract through 2016. The VJO includes a group of Vermont electric companies and municipal utilities, of which the Company is a participant. The VJO Power Contract has been in place since 1987, and related contracts were subsequently negotiated between the Company and Hydro-Quebec, which altered the terms and conditions contained in the original contract by reducing the overall power requirements and related costs.

There are specific contractual provisions that provide that in the event any VJO member fails to meet its obligation under the contract with Hydro-Quebec, the balance of the VJO participants, including the Company, will "step-up" to the defaulting party's share on a pro-rata basis. The VJO contract runs through 2020, but the Company's purchases related to the contract end in 2016. As of December 31, 2004, the Company's obligation is about 46 percent of the total VJO Power Contract through 2016, which translates to about $663 million, on a nominal basis. The average annual amount of capacity that the Company will purchase from January 1, 2005 through October 31, 2012 is about 144.4 MW, with lesser amounts purchased through October 31, 2016.

In accordance with guidance set forth in FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* ("FIN 45"), the Company is required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood is remote. In regards to the "step-up" provision in the VJO Power Contract, the Company must assume that all members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. The Company believes this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power in their most recent rate applications. Despite the remote chance that such an event could occur, the Company estimates that its undiscounted purchase obligation would be about an additional $777 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2005 and remained in default for the duration of the contract. In such a scenario, the Company would then own the power and could seek to recover its costs from the defaulting members or its retail customers, or resell the power in the wholesale power markets in New England. The range of outcomes (full cost recovery, potential loss or potential profit) would be highly dependent on Vermont regulation and wholesale market prices at the time.

In the early phase of the VJO Power Contract, two sellback contracts were negotiated, the first delaying the purchase of 25 MW of capacity and associated energy, the second reducing the net purchase of Hydro-Quebec power through 1996. In 1994, the Company negotiated a third sellback arrangement whereby it received a reduction in capacity costs from 1995 to 1999. In exchange for this sellback, Hydro-Quebec obtained two options. The first gives Hydro-Quebec the right upon four years' written notice, to reduce capacity deliveries by 50 MW beginning as early as 2010, including the use of a like amount of the Company's Phase I/II transmission facility rights. The second gives Hydro-Quebec the right upon one year's written notice to curtail energy deliveries in a contract year (12 months beginning November 1) from an annual load factor of 75 to 50 percent due to adverse hydraulic conditions in Quebec. This second option can be exercised five times through October 2015.

The Company has assessed the third sellback arrangement under the requirements of SFAS No. 133, and determined that the first option is a derivative, but the second is not a derivative because it is contingent upon a physical variable. The year-end estimated fair value of the first option was an unrealized loss of $5.7 million in 2004 and an unrealized loss of $1.2 million in 2003. The estimated fair value of this derivative is valued using a binomial tree model, and quoted market data when available along with appropriate valuation methodologies.

Under the VJO Power Contract, the VJO can elect to change the annual load factor from 75 percent to between 70 and 80 percent five times through 2020, while Hydro-Quebec can elect to reduce the load factor to not less than 65 percent three times during the same period of time. The VJO has made three out of five elections to date. Hydro-Quebec has used all three of its elections, resulting in a 65 percent load factor obligation from November 1, 2002 to October 31, 2005.

The Hydro-Quebec contracts are summarized in the table below, including average annual projections for the calendar years as shown (dollars in thousands, except per kWh amounts):

	2004	Estimated Average 2005 - 2012	Estimated Average 2013 - 2016
Annual Capacity Acquired	**142.8MW**	143.8MW	(a)
Minimum Energy Purchase – annual load factor	**63%**	(b)	(b)
Energy Charge	**$21,748**	$28,651	$20,164
Capacity Charge	**35,195**	33,932	20,476
Total Energy and Capacity Charge	**$56,943**	$62,583	$40,640
Average Cost per kWh	**$0.072**	$0.067	$0.071

(a) Annual capacity acquired is projected to be about 116 MW for 2013 through 2014 and 19 MW for 2016.
(b) Annual load factor is 65 percent for contract year ending October 31, 2005 and 75 percent for contract years ending October 31, 2006 through 2016.

The Company's estimated cost of energy and capacity under the existing contracts with Hydro-Quebec, based on the load factors shown in the table above, are $58.5 million in 2005, $62.1 million in 2006, $62.3 million in 2007, $63.1 million in 2008, and $64.0 million in 2009.

VYNPC The Company has a 35 percent entitlement in Vermont Yankee plant output sold by ENVY to VYNPC, through a long-term power purchase contract with VYNPC. One remaining secondary purchaser continues to receive a small percentage of the Company's entitlement, reducing its entitlement to about 34.83 percent. The long-term contracts between VYNPC and the entitlement holders and between VYNPC and ENVY became effective on July 31, 2002, the same day that the Vermont Yankee nuclear plant was sold to ENVY. The Company no longer bears the operating costs and risks associated with running the plant or the costs and risks associated with the eventual decommissioning of the plant. ENVY has no obligation to supply energy to VYNPC over the amount the plant is producing, so entitlement holders receive reduced amounts of energy when the plant is operating at a reduced level, and no energy when the plant is not operating.

The PPA through which VYNPC purchases power from ENVY and in turn sells to its sponsors includes prices that range from 3.9 cents to 4.5 cents per kilowatt-hour through March 2012. Effective November 2005, the contract prices are subject to a "low-market adjuster" that protects the Company and its power consumers if power market prices drop significantly. The low-market adjuster is a mechanism in which the PPA base contract price for each billing month is compared to a 12-month average (ending in same billing month) of hourly market prices as defined in the PPA. If the 12-month average market price is less than 95 percent of the base PPA contract price, then 105 percent of the 12-month average market price will be used for the billing month. The low-market adjusted price cannot exceed the base PPA contract price. If market prices rise, however, contract prices are not adjusted upward. In addition to PPA charges, VYNPC's billings to the sponsors include certain of its residual costs of service through a FERC tariff to the VYNPC sponsors. The PPA is expected to result in decreased costs over the life of the PPA when compared to the projected cost of continued ownership of the plant.

A summary of the Company's estimated purchases under the PPA follows:

	2004	Estimated Average 2005-2012
Average capacity acquired	182 MW	182 MW
Company share of plant output	34.8269%	34.8269%
Annual energy charge per mWh	$43.38	$41.34
Average total cost per mWh	$42.69	$42.44
Contract period		March 2012

In 2004, purchases amounted to about $58.7 million based on the Company's entitlement share of plant output. Future purchases are expected to be $57.1 million in 2005, $61.1 million in 2006, $58.0 million in 2007, $59.7 million in 2008 and $65.8 million in 2009.

In 2003, ENVY sought PSB approval to increase generation at the Vermont Yankee plant by 110 megawatts. The Company's purchases from VYNPC will not be affected by such increased generation and its entitlement percentage of plant output will decrease about 29 percent. On March 15, 2004, the PSB approved the proposal, but its approval was conditioned on ENVY providing an outage protection indemnification ("Ratepayer Protection Proposal" or "RPP") for the Company and Green Mountain Power in case the uprate causes temporary reductions in output that reduce the value of the PPA. The Company's maximum right to indemnification under the RPP is about $2.8 million, and will be in place for three years to cover any uprate related reductions in output.

Plant output has been reduced since the April 2004 scheduled refueling outage, and will continue until ENVY receives NRC approval for the uprate. This reduced the Company's entitlement by an average of about 4 MW during the period. The financial effect of such a reduction was covered under the terms of the RPP.

On June 18, 2004, an incident that caused a fire at the Vermont Yankee plant's transformer caused the plant to shut down for about 19 days. The Company deferred about $0.8 million of incremental replacement energy costs incurred as a result of the outage, per the PSB's preliminary approval of the Company's request for an Accounting Order. The Final Accounting Order is being addressed as part of the rate case. The Company believes that the plant went off line due to problems associated with uprate-related improvements made by ENVY, and the Company has sought about $0.8 million from ENVY to cover the incremental replacement energy costs resulting from the outage. ENVY contends that the problem would have occurred regardless of the uprate. The Company has engaged in discussions with ENVY relating to settlement of this dispute in accordance with the RPP. Having failed to reach a settlement, the Company petitioned the PSB for resolution. On February 18, 2005, the PSB held a prehearing conference and set a schedule that provides for resolution in the third quarter of 2005. The Company and ENVY have agreed to remain in settlement discussions relating to this matter.

In April 2004, in response to an NRC inspection conducted during the Vermont Yankee plant's scheduled refueling outage, ENVY reported that two short spent fuel rod segments were not in what ENVY believed to be their documented location in the spent fuel pool. According to ENVY, in 1979 the rods were placed in a special stainless steel container in the spent fuel pool. After initial document review and visual inspection of the spent fuel pool, ENVY did not locate the fuel rod segments. On May 5, 2004, ENVY notified VYNPC that based on the terms of the Purchase and Sale Agreement dated August 1, 2001, and facts at the time, it was their view that costs associated with the spent fuel rod segment inspection effort were the responsibility of VYNPC. On May 20, 2004, VYNPC responded that based on the information at the time there was no basis for ENVY's claim. Subsequently, ENVY's continuing documentation review led to the discovery of the fuel rod segments in a container in the spent fuel pool. The NRC has begun its own investigation into ENVY's accounting for these segments. The Company cannot predict the outcome of this matter at this time.

Nuclear industry practice typically is to maintain the capacity to off-load the entire active nuclear fuel core into the spent fuel pool as a safety measure; this is called maintaining full core discharge capability. ENVY anticipated that to maintain full core discharge capability, dry cask storage of spent nuclear fuel will be needed at the Vermont Yankee plant by late 2008 based on current operations or as early as 2007 if the NRC does grant permission to uprate the plant output. ENVY requires enabling legislation from the Vermont State Legislature and PSB approval for dry cask storage.

Independent Power Producers The Company receives power from several Independent Power Producers ("IPPs"). These plants primarily use water and biomass as fuel. Most of the power comes through a state-appointed purchasing agent, VEPP Inc. ("VEPPI"), which assigns power to all Vermont utilities under PSB rules. In 2004, the Company received 172,210 mWh under these long-term contracts, about 84 percent related to VEPPI. Total IPP purchases accounted for 6.8 percent of the Company's total mWh purchased and 12.2 percent of purchased power costs. Estimated purchases from IPPs are expected to be $18.7 million in 2005, $18.2 million in 2006, $19.1 million in 2007, $19.3 million in 2008 and $17.8 million in 2009. These amounts reflect annual savings of about $0.4 million related to the IPP settlement described below.

On January 15, 2003, the PSB issued a final order approving a settlement reached by the Company, other parties and the DPS, to reduce power costs associated with power purchases from IPPs. The settlement was related to various legal proceedings and negotiations that began in 1999 to change the IPPs' contracts with VEPPI to reduce power costs for customers' benefit. Nominal cost savings to all Vermont utilities are estimated to be about $8 million between 2005 and 2020, exclusive of savings that might result from implementation of IPP contract buy downs through securitization. The Company's share is about 39 percent of the power savings credits under the settlement. VEPPI began passing along power costs savings to all Vermont utilities in June 2003 when all conditions of the settlement were met. The Company's share amounted to $0.4 million in 2004 and $0.3 million in 2003. Per PSB approval of the settlement, the Company is recording these savings as a regulatory liability to be addressed in its pending rate proceeding.

Joint-ownership The Company's share of operating expenses for these facilities is included in the corresponding operating accounts on the Consolidated Statements of Income. Each participant in these facilities must provide for its financing.

As a joint owner of the Millstone Unit #3 facility, in which Dominion Nuclear Corporation ("DNC") is the lead owner with about 93.47 percent of the plant joint-ownership, the Company is responsible for its share of nuclear decommissioning costs. The Company has an external trust dedicated to funding its joint-ownership share of future decommissioning costs. DNC has suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements are being met or exceeded. The Company has also suspended contributions to the Trust Fund, but could choose to renew funding at its own discretion as long as the minimum requirement is met or exceeded. If a need for additional decommissioning funding is necessary, the Company will be obligated to resume contributions to the Trust Fund. See Note 8 - Financial Instruments and Investment Securities for more detail related to the Trust Fund and Note 1 - Summary of Significant Accounting Policies for discussion of asset retirement obligations.

In January 2004, DNC filed, on behalf of itself and the two minority owners, including the Company, a lawsuit against the DOE seeking recovery of costs related to storage of spent nuclear fuel arising from the failure of the DOE to comply with its obligations to commence accepting such fuel in 1998. The schedule for further proceedings in the lawsuit is not known at this time. Millstone Unit #3 spent fuel from the beginning of commercial operations in 1986 resides in the spent fuel pool, and there is believed to be adequate spent fuel pool storage capability to support expected operations through the end of its current licensed life in 2025. The Company continues to pay its share of the DOE Spent Fuel assessment expenses levied on actual generation and will share in recovery from the lawsuit, if any, in proportion to its ownership interest.

The Company's ownership interests in jointly owned generating and transmission facilities are set forth in the following table and are recorded in the Company's Consolidated Balance Sheets (dollars in thousands):

	Fuel Type	Ownership	In-Service Date	MW Entitlement	December 31 2004	2003
Wyman #4	Oil	1.7769%	1978	10.8	**$3,385**	$3,367
Joseph C. McNeil	Various	20.0000%	1984	10.8	**15,488**	15,485
Millstone Unit #3	Nuclear	1.7303%	1986	20.0	**76,450**	76,166
Highgate Transmission Facility		47.3500%	1985	N/A	**14,281**	14,303
					109,604	109,321
Accumulated depreciation					**55,260**	52,161
					$54,344	$ 57,160

Environmental Over the years, more than 100 companies have merged into or been acquired by the Company. At least two of the companies used coal to produce gas for retail sale. This practice ended more than 50 years ago. Gas manufacturers, their predecessors and the Company used waste disposal methods that were legal and acceptable then, but may not meet modern environmental standards and could represent liability.

Some operations and activities are inspected and supervised by federal and state authorities, including the Environmental Protection Agency. The Company believes that it is in compliance with all laws and regulations and has implemented procedures and controls to assess and assure compliance. Corrective action is taken when necessary. Below is a brief discussion of known material issues.

Cleveland Avenue Property The Cleveland Avenue property in Rutland, Vermont, was used by a predecessor to make gas from coal. Later, the Company sited various operations there. Due to coal tar deposits, Polychlorinated Biphenyl contamination and potential off-site migration, the Company conducted studies in the late 1980s and early 1990s to quantify the situation. Investigation has continued, and the Company is working with the State of Vermont to develop a mutually acceptable solution.

Brattleboro Manufactured Gas Facility In the 1940s, the Company owned and operated a manufactured gas facility in Brattleboro, Vermont. The Company ordered a site assessment in 1999 on request of the State of New Hampshire. In 2001, New Hampshire said no further action was required, though it reserved the right to require further investigation or remedial measures. In 2002, the Vermont Agency of Natural Resources notified the Company that its corrective action plan for the site was approved. That plan is now in place.

Dover, New Hampshire, Manufactured Gas Facility In 1999, PSNH contacted the Company about this site. PSNH alleged that the Company was partially liable for cleanup, since the site was previously operated by Twin State Gas and Electric, which merged into the Company the same day that PSNH bought the facility. In 2002, the Company reached a settlement with PSNH in which certain liabilities it might have had were assigned to PSNH in return for a cash payment.

As of December 31, 2004 and 2003, reserves of $6.1 million and $7.2 million are recorded on the Consolidated Balance Sheets. The reserve represents Management's best estimate of the cost to remedy issues at these sites. There is no pending or threatened litigation regarding other sites with the potential to cause material expense. No government agency has sought funds from the Company for any other study or remediation.

In the second quarter of 2004, the Company reached a confidential settlement with one of its insurance carriers. The settlement is reflected in Other Operation on the Consolidated Statements of Income.

Leases and support agreements *Capital Leases:* The Company participated with other electric utilities in the construction of the Phase I Hydro-Quebec interconnection transmission facilities in northeastern Vermont, which were completed at a total cost of about $140 million. Under a support agreement relating to participation in the facilities, the Company is obligated to pay its 4.55 percent share of Phase I Hydro-Quebec capital costs over a 20-year recovery period ending in 2006. The Company also participated in the construction of Phase II Hydro-Quebec transmission facilities constructed throughout New England, which were completed at a total cost of about $487 million. Under a similar support agreement, the New England participants, including the Company, contracted to pay their proportionate share of the total cost of constructing, owning and operating the Phase II facilities, including capital costs. The Company is obligated to pay its 5.132 percent share of Phase II Hydro-Quebec capital costs over a 25-year recovery period ending in 2015. These agreements meet the capital lease accounting requirements under SFAS No. 13, Accounting for Leases. All costs under these agreements are recorded as purchased transmission expense in accordance with the Company's ratemaking policies. Future expected payments will range from about $3.7 million to $2.7 million annually from 2005 through 2015 and will decline thereafter. Approximately $0.6 million of the annual costs are reimbursed to the Company pursuant to the New England Power Pool Open Access Transmission Tariff.

For the year ended December 31, 2004, imputed interest on capital leases totaled $0.8 million. The following table summarizes the minimum lease payments associated with the Phase I and Phase II Hydro-Quebec arrangements and other capital leases at December 31, 2004:

Year	(in thousands) Capital Leases
2005	$1,019
2006	940
2007	701
2008	696
2009	696
Thereafter	4,062
Future minimum lease payments	$8,114
Plus amount representing interest	3,700
Present value of future minimum lease payments	$11,814

Operating Leases: The Company leases its vehicles and related equipment under one operating lease agreement. The leases are mutually cancelable one year from each individual lease inception. The Company has the ability to lease vehicles and related equipment up to an aggregate unamortized balance of $10 million, of which about $4.4 million was outstanding for the years ended 2004 and 2003.

Under the terms of the vehicle operating lease, the Company has guaranteed a residual value to the lessor in the event the leased items are sold. The guarantee provides for reimbursement of up to 87 percent of the unamortized value of the lease portfolio. Under the guarantee, if the entire lease portfolio had a fair value of zero at December 31, 2004, the Company would have been responsible for a maximum reimbursement of $3.9 million and at December 31, 2003, the Company would have been responsible for a maximum reimbursement of $3.8 million. The Company had a liability of $0.1 million at December 31, 2004 representing its obligation under the guarantee based on the fair market value of the entire portfolio.

Other operating lease commitments are considered minimal, as most are cancelable after one year from inception. Total rental expense, including the operating lease agreement described above, included in the determination of net income, amounted to about $5.2 million in 2004, $4.4 million in 2003 and $4.5 million in 2002.

Catamount In September 1995, Catamount's wholly owned subsidiary, Equinox Vermont Corporation, verbally agreed to indemnify Tractebel Power Operations, Inc. ("Tractebel") for up to 33.1126 percent of the amount the actual price of fuel charged to Ryegate Associates (the "Partnership") exceeds the fuel price guaranteed to the Partnership's lender by Tractebel. The fuel price guarantee will expire in 2008. Based on Catamount's long-term forecast for wood fuel prices, Catamount does not anticipate the actual fuel price for the Partnership will exceed the fuel price guaranteed to the Partnership lender through 2008.

As part of its windfarm development efforts, in August 2004, Catamount entered into a construction lending arrangement for about $27.5 million for a wind project located in the Unites States. At December 31, 2004, Catamount advanced $22.6 million for construction of the project. On February 11, 2005, the construction loan was paid off and Catamount made an equity investment in the wind project.

In November 2004, Catamount entered into an agreement with a third-party developer for the purchase of wind turbines for a joint development project. Pursuant to the agreement, Catamount made a total of $5.9 million of payments to the turbine supplier in the fourth quarter of 2004. The turbine supply agreement calls for payments of $5.9 million in March 2005 and $14.8 million in September 2005, with the remaining contract amount of $32.5 million due based on milestones established in the agreement. Catamount expects third-party construction financing, for the wind project that the turbine agreement is associated with, to be in place in the second quarter of 2005. Once the construction financing is in place, Catamount would be relieved of making the September 2005 and remaining payments to the turbine supplier. The turbine supply agreement allows for termination in full up to 30 days prior to the delivery of the first turbines. After that date, Catamount can terminate future turbines (partial termination) 30 days prior to scheduled delivery. In the event of a termination of the turbine supply agreement in whole or in part for the joint development project, the third-party developer or Catamount has up to 18 months from the termination date to utilize the turbines and receive reimbursement of 85 percent of the turbine down-payments.

Legal proceedings The Company is involved in legal and administrative proceedings in the normal course of business and does not believe that the ultimate outcome of these proceedings will have a material adverse effect on its financial position or results of operations, except as otherwise disclosed herein.

Change of control The Company has management continuity agreements with certain officers that become operative upon a change in control of the Company. Potential severance expense under the agreements varies over time depending on several factors, including the specific plan for individual officers and officers' compensation and age at the time of the change of control.

NOTE 14 – SEGMENT REPORTING

The Company's reportable operating segments include: **Central Vermont Public Service Corporation ("CV"),** which engages in the purchase, production, transmission, distribution and sale of electricity in Vermont. Custom Investment Corporation is included with CV in the table below; **Catamount Energy Corporation ("Catamount"),** which invests in unregulated, energy generation projects in the United States and the United Kingdom, and **All Other,** which includes operating segments below the quantitative threshold for separate disclosure. These operating segments include: 1) Eversant Corporation ("Eversant"), which engages in the sale or rental of electric water heaters through a subsidiary, SmartEnergy Water Heating Services, Inc., to customers in Vermont and New Hampshire; 2) C.V. Realty, Inc., a real estate company whose purpose is to own, acquire, buy, sell and lease real and personal property and interests therein related to the utility business, and 3) Catamount Resources Corporation, which was formed to hold the Company's subsidiaries that invest in unregulated business opportunities. Prior to January 1, 2003, Eversant was reported as a separate segment; it no longer meets the quantitative threshold, therefore, all prior period amounts have been restated in the table below.

The accounting policies of the operating segments are the same as those described in the summary of significant accounting policies. Intersegment revenues include revenues for support services, including allocations of software systems and equipment, to Catamount and Eversant. Due to the sale of Connecticut Valley's franchise and net plant assets as described in Note 4 – Discontinued Operations, its results of operations are reported as discontinued operations and its assets are reported as held for sale in the segment table below.

The intersegment sales and services for each jurisdiction are based on actual rates or current costs. The Company evaluates performance based on stand-alone operating segment net income.

Financial information by industry segment for 2004, 2003 and 2002 is as follows (in thousands):

2004	CV VT	Catamount Energy Corporation	All Other	Discontinued Operations	Reclassification and Consolidating Entries	Consolidated
Revenues from external customers	$302,200	$1,597	$1,845	-	$(3,442)	$302,200
Intersegment revenues	90	-	-	-	(90)	-
Depreciation and other (1)	12,254	69	171	-	(240)	12,254
Operating income tax expense (benefit)	1,056	(1,927)	340	-	1,587	1,056
Operating income (loss)	12,879	(4,327)	423	-	3,904	12,879
Equity in earnings – utility affiliates (2)	1,225	-	-	-	-	1,225
Equity in earnings – non-utility affiliates (3)	-	4,220	-	-		4,220
Gain on sale of non-utility investments	-	2,518	-	-	-	2,518
Other income (4)	1,919	4,592	66	-	2,268	8,845
Other deductions	8,729	599	54	-	(127)	9,255
Interest income (4)	3,467	2,007	18	-	(105)	5,387
Interest expense	9,579	280	-	-	-	9,859
Income from continuing operations	7,386	3,606	423	-	-	11,415
Income from discontinued operations, net of tax (including gain on disposal of $12,354)	-	-	-	$12,340	-	12,340
Investments in affiliates	16,070	-	-	-	-	16,070
Total assets	487,567	61,029	15,247	-	(17,080)	546,763
Construction and plant expenditures	20,174	-	-	-	-	20,174
2003						
Revenues from external customers	$306,014	$527	$1,908	-	$(2,435)	$306,014
Intersegment revenues	98	-	-	-	(98)	-
Depreciation and other (1)	21,428	69	172	-	(241)	21,428
Operating income tax expense (benefit)	10,125	(1,808)	325	-	1,483	10,125
Operating income (loss)	24,019	(2,425)	818	-	1,607	24,019
Equity in earnings – utility affiliates (2)	1,801	-	-	-	-	1,801
Equity in earnings – non-utility affiliates (3)	-	6,362	-	-		6,362
Other income (4)	3,449	2,488	112	-	1,162	7,211
Other deductions	10,575	478	50	-	(248)	10,855
Interest income (4)	1,560	2,244	63	-	(5)	3,862
Interest expense	11,083	657	-	-	-	11,740
Income from continuing operations	17,102	736	517	-	-	18,355
Income from discontinued operations	-	-	-	$1,446	-	1,446
Investments in affiliates	9,303	-	-	-	-	9,303
Assets held for sale	-	-	-	9,292	-	9,292
Total assets	469,838	48,300	3,874	9,292	(2,640)	528,664
Construction and plant expenditures	14,959	-	-	531	(531)	14,959
2002						
Revenues from external customers	$294,390	$2,567	$2,002	-	$(4,569)	$294,390
Intersegment revenues	123	-	-	-	(123)	-
Depreciation and other (1)	13,426	77	207	-	(284)	13,426
Asset impairment charges (3)	-	2,774	-	-	-	2,774
Operating income tax expense (benefit)	11,009	1,376	(316)	-	(1,060)	11,009
Operating income (loss)	25,203	(6,551)	(1,014)	-	7,565	25,203
Equity in earnings – utility affiliates (2)	3,909	-	-	-	-	3,909
Equity in earnings – non-utility affiliates (3)	-	11,650	-	-	-	11,650
Other income (4)	2,981	1,925	136	-	1,772	6,814
Other deductions	16,659	2,937	169	-	(2,883)	16,882
Interest income (4)	1,265	2,008	48	-	(23)	3,298
Interest expense	11,624	1,171	(336)	-	-	12,459
Income (loss) from continuing operations	17,128	1,541	(445)	-	-	18,224
Income from discontinued operations	-	-	-	$1,543	-	1,543
Investments in affiliates	23,716	-	-	-	-	23,716
Assets held for sale	-	-	-	9,242	-	9,242
Total assets	459,833	60,743	13,539	9,242	(5,240)	538,117
Construction and plant expenditures	13,885	-	-	557	(557)	13,885

(1) Includes net deferral and amortization of nuclear replacement energy and maintenance costs (included in Purchased power) and amortization of conservation and load management costs (included in Other operation expenses) in the accompanying Consolidated Statements of Income.

(2) See Note 2 herein for CV's investments in affiliates.

(3) See Note 3 herein for CV's investment in non-utility affiliates.

(4) Interest income is included in Other income. See Note 1 herein for pre-tax components of Other income.

NOTE 15 – UNAUDITED QUARTERLY FINANCIAL INFORMATION

The following quarterly financial information is unaudited and includes all adjustments consisting of normal recurring accruals which are, in the opinion of Management, necessary for a fair statement of results of operations for such periods. For 2004 and 2003, all quarterly information reported has been restated to reflect the impact of discontinued operations. See Note 4 – Discontinued Operations for additional information related to the sale. The amounts included in the table below are in thousands, except per share amounts:

	Quarter Ended				
2004	March	June	September	December	Total (a)
Operating revenues	$84,114	$67,635	$72,740	$77,711	$302,200
Operating (loss) income	$(620)	$3,988	$5,786	$3,725	$12,879
(Loss) income from continuing operations	$(1,906)	$3,414	$6,057	$3,850	$11,415
Income (loss) from discontinued operations	12,256	90	8	(14)	12,340
Less dividends on preferred stock	258	258	259	(407)	368
Net income available for common stock	$10,092	$3,246	$5,806	$4,243	$23,387
Basic earnings (loss) per share from:					
Continuing operations	$(.18)	$.26	$.48	$.35	$0.91
Discontinued operations	1.02	.01	-	-	1.02
Total basic earnings per share	$.84	$.27	$.48	$.35	$1.93
Diluted earnings (loss) per share from:					
Continuing operations	$(.18)	$.26	$.47	$.34	$0.90
Discontinued operations	1.00	.01	-	-	1.00
Total diluted earnings per share	$.82	$.27	$.47	$.34	$1.90
2003					
Operating revenues	$79,476	$73,588	$73,839	$79,111	$306,014
Operating income	$6,841	$6,177	$5,528	$5,473	$24,019
Income from continuing operations	$4,600	$4,800	$4,545	$4,410	$18,355
Income from discontinued operations	359	295	380	412	1,446
Less dividends on preferred stock	299	300	300	299	1,198
Net income available for common stock	$4,660	$4,795	$4,625	$4,523	$18,603
Basic earnings per share from:					
Continuing operations	$.36	$.38	$.36	$.35	$1.45
Discontinued operations	.04	.02	.03	.03	.12
Total basic earnings per share	$.40	$.40	$.39	$.38	$1.57
Diluted earnings per share from:					
Continuing operations	$.35	$.38	$.35	$.34	$1.41
Discontinued operations	.04	.02	.03	.03	.12
Total diluted earnings per share	$.39	$.40	$.38	$.37	$1.53

(a) The summation of quarterly earnings per share data may not equal annual data due to rounding.

Management is responsible for the preparation, integrity and fair presentation of the accompanying consolidated financial statements of Central Vermont Public Service Corporation. The accompanying financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. The financial statements include amounts that are based on management's best estimates and judgments. Management also prepared the other financial information presented in this Annual Report and is responsible for its accuracy and consistency with the financial statements.

The Company has established and maintains an accounting system and a related system of internal accounting controls directed toward safeguarding assets and providing accurate and reliable financial information. An integral part of the system of internal accounting controls is an internal audit function designed to monitor compliance with the Company's accounting and financial reporting policies and procedures. Management believes that the Company's accounting system and related system of internal accounting controls are adequate to achieve the objectives discussed above.

The independent registered public accounting firm of Deloitte & Touche LLP, has been retained to audit the Company's financial statements. The accompanying "Report of Independent Registered Public Accounting Firm" found on page 24 of this Annual Report, is based on their audit conducted in accordance with generally accepted auditing standards.

The Audit Committee of the Board of Directors is composed solely of outside directors, and is responsible for the selection of the registered independent public accounting firm to be retained in the audit of the Company's financial statements. The Audit Committee meets periodically and privately with the independent public accountants, with the internal auditors, as well as Company management, to review accounting, auditing, internal accounting controls and financial reporting matters.

Robert H. Young
President and
Chief Executive Officer

Jean Gibson
Senior Vice President, Chief
Financial Officer and Treasurer

COMMON STOCK PRICES AND DIVIDENDS

2004	High	Low	Dividends Per Share
1st quarter	$24.08	$21.76	$.23
2nd quarter	22.50	18.45	.23
3rd quarter	21.75	19.15	.23
4th quarter	24.03	20.15	.23

2003	High	Low	Dividends Per Share
1st quarter	$19.00	$16.52	$.22
2nd quarter	19.95	17.00	.22
3rd quarter	22.99	19.40	.22
4th quarter	24.50	22.10	.22

SHAREHOLDER INFORMATION

Information regarding stock transfer, lost certificates, dividend checks, dividend reinvestment, optional cash investments, automatic monthly investments from bank accounts, and direct deposit of dividend payments are directed to the transfer agent as noted below. Please include a reference to Central Vermont Public Service and a telephone number where you can be reached.

Registrar, Transfer Agent and Dividend Disbursing Agent for Common and Preferred Stocks:

American Stock Transfer and Trust Company
59 Maiden Lane
New York, New York 10038
1-800-937-5449
www.amstock.com

You may also contact CVPS Shareholder Services at 1-800-354-2877, on the Internet at http://www.cvps.com, or by e-mail at shsvcs@cvps.com.

ANNUAL MEETING

The Annual Meeting of Shareholders is scheduled for 10 a.m. on Tuesday, May 3, 2005, at the Paramount Theatre, 30 Center Street, Rutland, Vermont. Notice of the meeting and proxy statement and proxy will be mailed to holders of Common Stock.

DIVIDEND REINVESTMENT AND COMMON STOCK PURCHASE PLAN

Shareholders may reinvest dividends and make monthly cash investments of at least $100 and no more than $5,000 per month. Purchase of shares is optional, regardless of whether dividends are reinvested. This is not an offer to sell, nor a solicitation of an offer to buy, any securities. Any stock offering will be made only by prospectus. For further information, please contact American Stock Transfer and Trust Company at the address above.

COMMON STOCK LISTING

Central Vermont Common Stock is listed on the New York Stock Exchange under the trading symbol CV. Newspaper listings of stock transactions use the abbreviation CVtPS or CentlVtPS and the internet trading symbol is CV.

DIVIDENDS

All dividends paid by the company represent taxable income to shareholders for federal income tax purposes. No portion of the 2004 dividend was a return of capital.

Traditionally, the Board of Directors declares dividends to be payable on the 15th day of February, May, August, and November to shareholders of record on the last business day of the month prior to payment.

DISCLOSURES

For the year ended 2004, the company submitted a Section 12(a) Chief Executive Officer certification to the New York Stock Exchange and the Company has also filed certifications for the Chief Executive Officer and Chief Financial Officer with the Securities and Exchange Commission as required under Section 302 of the Sarbanes-Oxley Act.

CREDIT RATINGS

The table below indicates ratings of the Company's securities as of February 2005.

	Standard & Poor's	Fitch
Corporate Credit Rating	BBB-	N/A
First Mortgage Bonds	BBB+	BBB+
Preferred Stock	BB	BBB-

All of Central Vermont's ratings have a stable outlook.

FINANCIAL INFORMATION

We welcome inquiries from individuals and members of the financial community. Please direct your inquiries to:

Jean H. Gibson, Chief Financial Officer
Central Vermont Public Service
77 Grove Street
Rutland, VT 05701

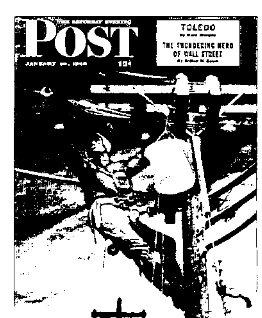
FORM 10-K

The corporation will furnish, without charge, a copy of its most recent annual report to the Securities and Exchange Commission (Form 10-K) upon receipt of a written request. Please write:

Dale A. Rocheleau, Secretary
Central Vermont Public Service
77 Grove Street
Rutland, VT 05701

ABOUT THE COVER

The January 10, 1948 cover of *The Saturday Evening Post* featured a painting by Mead Schaeffer of CVPS line worker Howard Stevens using a block and tackle to tighten a line near Bennington. © Curtis Publishing



(Seated) Robert H. Young, Rhonda L. Brooks, Mary Alice McKenzie and Frederic H. Bertrand. (Standing) George MacKenzie Jr., Janice B. Case, Robert G. Clarke, Janice L. Scites, Bruce M. Lisman, Timothy S. Cobb, and Robert L. Barnett.

DIRECTORS

Frederic H. Bertrand
(68)/1984/Chair of the Board, Central Vermont Public Service; Retired Chair of the Board and Chief Executive Officer, National Life Insurance Co., Montpelier, Vermont (1)(4)

Robert L. Barnett
(64)/1996/Former Executive Vice President, Motorola Inc., Schaumburg, Illinois (Communications Equipment) (3)(4)

Rhonda L. Brooks
(52)/1996/President, R. Brooks Advisors Inc., Pinehurst, North Carolina (Consulting Firm) (3)

Janice B. Case
(52)/2002/Former Senior Vice President, Energy Solutions, Florida Power Corporation, St. Petersburg, Florida (Electric Utility) (2)

Robert G. Clarke
(54)/1997/Chancellor of the Vermont State Colleges, Waterbury, Vermont (2)

Timothy S. Cobb
(63)/2000/Retired Chair, President and Chief Executive Officer, Salient 3 Communications Inc., Seneca, South Carolina (Design and Engineering of Electric Power Facilities) (3)

Bruce M. Lisman
(57)/2004/Senior Managing Director, The Bear Stearns Companies Inc., New York, New York (3)

George MacKenzie Jr.
(55)/2001/Former Executive Vice President and Chief Financial Officer, Glatfelter Company, York, Pennsylvania (Global Manufacturer of Specialty Papers and Engineered Products) (2)(4)

Mary Alice McKenzie
(47)/1992/Vice President and General Counsel, Vermont State Colleges, Waterbury, Vermont (1)(3)(4)

Janice L. Scites
(54)/1998/President, Scites Associates Inc., Basking Ridge, New Jersey (Technology and Business Consulting Firm) (2)

Robert H. Young
(57)/1995/President and Chief Executive Officer, Central Vermont Public Service (1)

(1) Member of Executive Committee
(2) Member of Audit Committee
(3) Member of Compensation Committee
(4) Member of Corporate Governance Committee

OFFICERS

Robert H. Young
(57)/1987/President and Chief Executive Officer

William J. Deehan
(52)/1985/Vice President, Transmission and Generation Planning and Regulatory Affairs

Joan F. Gamble
(47)/1989/Vice President, Strategic Change and Business Services

Jean H. Gibson
(48)/2002/Senior Vice President, Chief Financial Officer, and Treasurer

Joseph M. Kraus
(50)/1981/Senior Vice President, Engineering and Operations

Dale A. Rocheleau
(46)/2003/Senior Vice President for Legal and Public Affairs, and Corporate Secretary

Central Vermont Public Service

1929–2004 SELECTED COMPANY MILESTONES

1929

1941

1946

1954

1960

1963

1973

1974

1981

1987

1990

1998

1999

2002

2004

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