ISO new england

2004

annual report

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About ISO New England

ISO New England helps protect the health of New England's economy and the well-being of its people by ensuring the constant availability of electricity, today and for future generations. ISO New England meets this obligation in three ways: by ensuring the day-to-day reliable operation of New England's bulk power generation and transmission system, by overseeing and ensuring the fair administration of the region's wholesale electricity markets, and by managing comprehensive, regional planning processes.

Created in 1997, ISO New England is an independent, not-for-profit organization. Its board of directors and 400 employees have no financial interest in any company doing business in the region's wholesale electricity marketplace. ISO New England serves a six-state region that includes Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

Letter from the President and CEO

With its six diverse states, its intricate power requirements, and its status as a forerunner of deregulation, New England stands as one of the most complex energy management regions in the United States. At stake is the basic ability of industries, institutions and individuals to function.

ISO New England plays a vital role within this challenging environment: to ensure the constant availability of electricity today and for future generations. As an independent entity, ISO New England is able to look upon the future—not any individual interest—as one of our most important constituencies. This is essential for ensuring that electricity in New England is reliable and reasonably priced, now and in the long-term, which we believe are fundamental benefits for the region's residents and businesses.

ISO New England works to enable these benefits by developing and administering competitive wholesale electricity markets. When companies compete, they introduce efficiencies, invest in improvements, introduce innovations, improve overall performance and reduce costs. As we already have experienced in our six-state region, competitive markets provide positive economic and environmental outcomes for consumers and improve the ability of the power system to meet ever-increasing demand efficiently.

As we mark our fifth full year of market operations, it is an appropriate time to reflect on our origins, our progress and our objectives. This report describes:

Why markets were implemented: Markets were created to provide less-expensive, more-efficient and more-reliable electricity. It is ISO New England's responsibility to give competitive markets the ability to achieve their full potential in delivering benefits to consumers.

How they have succeeded: New England's markets are among the most competitive in the nation and already deliver significant consumer savings. Our wholesale electricity prices, adjusted for fuel costs, decreased by 5.7 percent since the first full year of market operations and experienced a dramatic decline of 11 percent from 2001 to 2004. Moreover, investors have financed a 30 percent increase in clean and efficient electricity supply.

Why markets must evolve over time: ISO New England works closely with the industry, regulators and other stakeholders to continually refine our model of competitive markets to ensure the marketplace works with maximum efficiency, competitiveness and fairness, thereby providing reliability and consumer benefits for years to come.

Why planning is essential: ISO New England plans in ways that will secure the future, and we do this by anticipating needs well in advance of those needs becoming reality. Our job is to weigh the feasibility of various actions and to make recommendations and shape policies that meet the energy demands of the region's economy and its people.

How enhanced oversight and governance promises benefits into the future: ISO New England is now a full-service regional transmission organization (RTO) providing reliability, efficiency and consumer protections, with one of the lowest annual operating budgets of any ISO or RTO in North America. With strengthened independence, we will not hesitate to move forward, to make the tough calls, and to rally to action in the name of protecting the reliability of the bulk power system and the efficiency of the wholesale markets.

ISO New England faces growing complexities every day, yet we bring to our work open minds, creative thinking, love of innovation and ever-better technical expertise that helps us answer the energy requirements of our region. We understand the role we play in ensuring public trust and are wholly committed to the cause.

Sincerely,

Gordon van Welie

The Move to Markets: Seeking Benefits Through Efficiency

For a century, regulated electricity monopolies did everything to produce, transmit and sell power to consumers, and utilities accepted reasonable returns on their investments. This system, like those in other regulated industries, was inefficient, offered few incentives for innovation and efficiency, and kept prices high.

Regulated sectors, such as airlines, banking and telecommunications, were restructured beginning in the 1970s, introducing dynamic new market forces. These forces first entered the energy sector through the natural gas industry, where combined with the unbundling of services and greater market transparency, resulted in a less expensive, more efficient and more reliable product.

In 1992, Congress passed the Energy Policy Act, the first step towards introducing competition to the wholesale electric power industry. The key to true competition was deemed to be open and equal access to the transmission grid; without such access, new entrants would face costly and discriminatory barriers. The Federal Energy Regulatory Commission (FERC) implemented the act by issuing orders that mandated fair access for all competitors and encouraged states to restructure their electric power systems.

The response among states varied, with some embracing competition. Nowhere was restructuring more enthusiastically embraced than in New England, where electric rates were among the highest in the country. Five of the six states required utilities to divest their power plants. Today, with 88 percent of its electricity generation unregulated, New England has the nation's most disaggregated marketplace and a strong foundation for achieving successful competitive markets for electricity.

New England's Markets Quickly Demonstrate Returns

FERC recognized that independent oversight was needed for the electric utility industry to transition from a regulated system to one that provided open access to the transmission system and a competitive marketplace. "Independent system operators" (ISOs) were created and given responsibility for ensuring power grid reliability and creating and administering wholesale markets. These independent entities would give competitive markets the ability to achieve their full potential in delivering benefits to consumers.

ISO New England was formed in 1997 to oversee New England's six-state region, with its highly integrated pool of electric utilities that had been running a centrally planned and dispatched bulk power system. ISO New England was joined by ISOs in other regions, including the Mid-Atlantic, and in single states, such as New York and California.

As a not-for-profit corporation, ISO New England oversees the regional power system, or *grid,* made up of more than 350 generators, 8,000 miles of high-voltage transmission lines, and 12 interconnections to neighboring systems—all serving 6.5 million New England businesses and households.

In 1999, ISO New England launched wholesale markets with approximately 160 participants. Today, there are more than 260 participating companies and entities that complete more than $7.25 billion of wholesale electricity transactions annually.

New England's markets quickly demonstrated real returns; wholesale electricity prices, after adjustment for fuel costs, decreased by 5.7 percent since the first full year of market operations. The region's prices experienced a dramatic decline of 11 percent over the four-year period from 2001 to 2004.

What's more, the introduction of wholesale markets has not sacrificed but strengthened the availability and delivery of electricity throughout the region. The lights stayed on in most of New England during the August 2003 Northeast Blackout—and an audit conducted by the North American Electric Reliability Council in response to the Blackout found that ISO New England system operators exceed industry requirements for training and certification, citing New England's operating procedures as best practices for the industry.

Evolving Markets Advance Reliability, Economic and Environmental Benefits

Markets Promote Growth and Investment in the Region

When ISO New England began operations in 1997, formal wholesale electricity markets did not exist. Instead, electricity was dispatched from generators based on longstanding power pooling practices. Working with regulators, the industry, and other stakeholders, ISO New England developed "interim markets" that began the evolution from regulation to functioning markets.

Investors responded to the promise of competitive markets by financing a 30 percent increase in power supplies, building highly efficient and clean plants through a newly established merchant power sector. These investments significantly improved reliability and competition.

For the first time, New England consumers were not responsible for the cost of power plant development, as state restructuring policy eliminated the guaranteed recovery of power plant investment that electric utilities had traditionally received through retail rates. This policy also reduced exposure to stranded costs, the costs and losses of poor utility investment decisions that had previously been paid for by consumers.

Moreover, the introduction of markets provided new and more transparent information about the performance of the power system, helping to identify needed infrastructure improvements, including transmission investment of nearly $4 billion.

Market Forces Drive Efficiencies and Reduce Wholesale Market Costs

Competitive markets have also created incentives to improve the operation, utilization, efficiency and overall performance of existing generation and transmission facilities. For example, plant owners responding to wholesale prices are motivated to keep their plants well maintained, available in times of greatest need and running when demand is highest. This increase in "generator availability" has reduced the need to build additional plants and lowered wholesale market costs.

In addition, the investment in new, efficient generation has resulted in a reduction in the use of less efficient and more polluting power plants, delivering environmental as well as economic benefits to New England consumers. Specifically, the move to more efficient gas-fired generators has decreased the use of the region's oil and older gas power plants and is estimated to have reduced annual carbon dioxide emissions by 6 percent, nitrogen oxide emissions by 32 percent, and sulfur oxide emissions by 48 percent from these units from 2000 to 2004.

The additional generation, along with the competitive market incentives to improve generator availability, enhance operation and make infrastructure investment more efficient, has led to a reduction in wholesale market costs of approximately $700 million annually (after adjustment for fuel costs). Progress such as this is evidence that markets are working to meet their objective of delivering significant value to consumers.

Building on the Success of the Markets

Despite these developments, the interim markets lacked several essential elements. Missing were 1) risk-management tools, such as a day-ahead market to protect against price volatility that can occur in real-time, and 2) efficiency mechanisms, including pricing that accurately reflects power system needs by calculating the true cost of producing and supplying power at numerous locations on the system. In 2000, ISO New England and market participants set out to develop and implement these tools and mechanisms.

In 2001, ISO New England and the market participants decided to adopt the market system used by PJM Interconnection, the system operator for the Mid-Atlantic States, as the most cost-effective means of providing these features. This approach would create standardized markets with an appropriate level of flexibility to preserve best practices while adapting to the unique needs and characteristics of New England. The "Standard Market Design" (SMD) solution also offered the benefit of minimizing "seams" among the Northeast markets, permitting broader trading of energy.

Increasing Benefits Through Standard Market Design

ISO New England successfully inaugurated SMD in March 2003. SMD's leading-edge features, such as eight pricing zones for electricity, a trading hub for added market liquidity, and a day-ahead market, have brought further improvements and benefits to New England, including:

- Improved trading and risk-management opportunities for wholesale market participants
- Improved reliability by accounting for physical system constraints when dispatching the bulk power system
- Better market signals for targeting investments in new bulk power system facilities
- The ability of state utility regulators to enable retail competition

Advancing Demand Response for a Balanced Market

Another important benefit of SMD for New England takes the form of greater incentives for energy efficiency programs, including demand response programs. "Demand response" refers to customers' response to either high wholesale prices or system reliability events through a reduction of their electricity consumption in exchange for compensation based on wholesale market prices. It is an important part of a balanced wholesale market. Yet achievement of an adequate amount of demand responsiveness is a significant challenge facing today's markets.

New England's demand response programs have encouraged the reduction in consumption and the use of small, on-site generators to improve reliability, lower prices, and reduce price volatility during periods of high demand and/or high wholesale electricity prices.

Since the inception of SMD, the demand response programs have yielded a twofold increase in these resources available to the wholesale market, plus total customer payments of approximately $3.4 million for reductions in energy consumption. Ongoing improvements include the ability for demand response customers to directly bid into the markets and the greater use of demand response programs to enhance system reliability.

New England's Planning Processes Ensure Continued Progress

Wholesale Markets Planning

While SMD offers a solid foundation for meeting the region's present and future electricity needs, ISO New England is spearheading continued market improvements through its Wholesale Markets Plan. Created through an annual, iterative process for the development of the markets, the Wholesale Markets Plan benefits consumers in two ways: it guides consideration and implementation of a broad array of improvements, such that market participants have the ability to make informed decisions about future purchases and investments, and it assists ISO New England in bringing improvements to the markets in an organized and cost-effective manner.

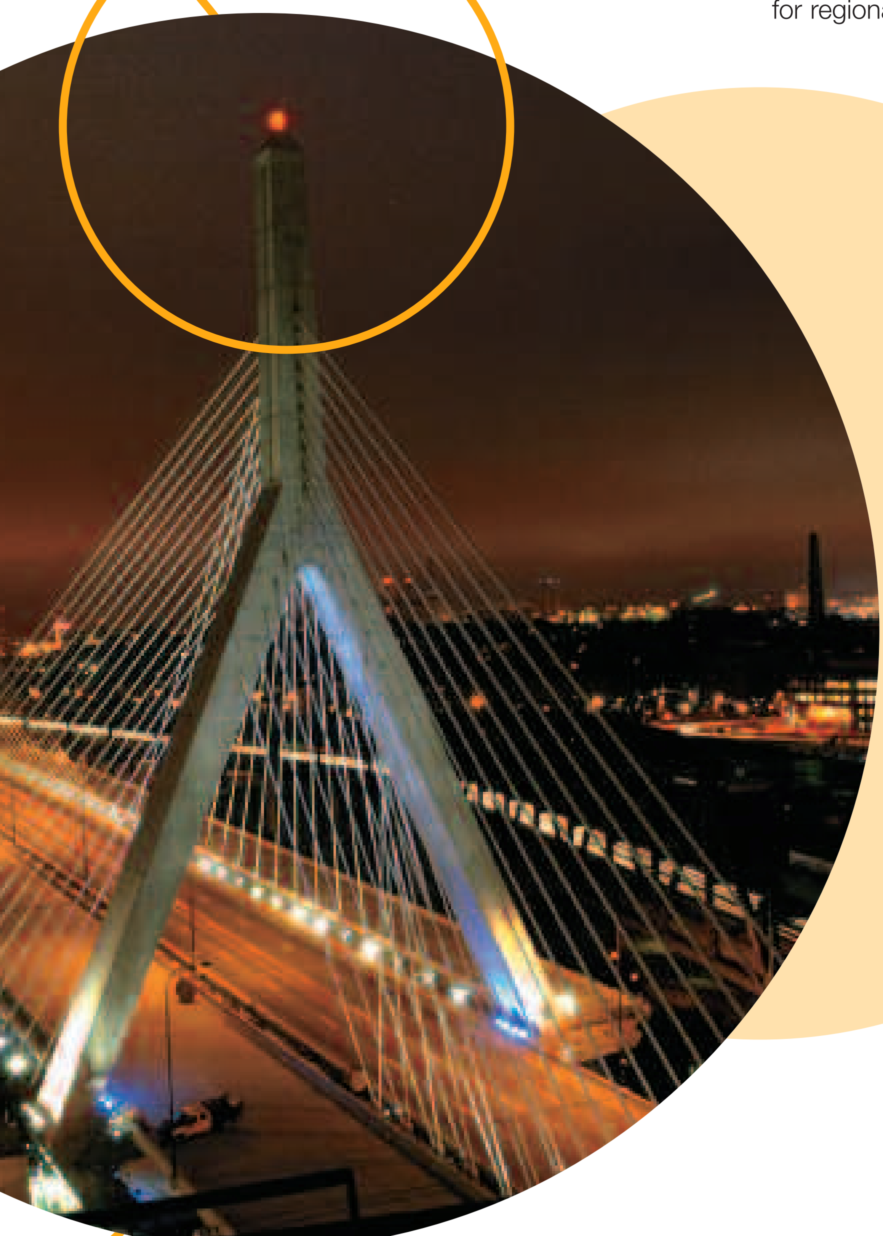
As part of the Wholesale Markets Plan, and as directed by FERC, ISO New England has proposed a locational installed capacity (LICAP) mechanism for implementation in 2006. While generation has grown, some existing capacity is outdated or uneconomical, and additional generation is needed in Southwest Connecticut and greater Boston. In the longer term, resources will be needed regionwide to keep pace with growing demand. Currently, there are few new supply resources being proposed for the region. The LICAP proposal advanced by ISO New England will further improve the efficiency of the New England market, promoting investment of needed resources in the right locations—while continuing to reduce risk for consumers and investors.

Power System Planning

ISO New England's annual system planning process, initiated in 2001, is a national model that has been recognized by the U.S. Department of Energy. The process is led by ISO New England in collaboration with industry representatives, state regulators and public officials. The result has been the identification of more than 270 transmission projects totaling $2.2–$4 billion—to be built by transmission owners—needed to preserve and increase reliability and market efficiency.

The process first encourages a marketplace response for solutions—funded by investors—to identified reliability and efficiency needs. In this regard, the planning process is resource-neutral, and all solutions, whether generation, merchant transmission or demand response, are considered equally. Regulated transmission projects are identified in the event that market solutions do not fully respond to system needs. If regulated transmission projects must go forward, ISO New England ensures the costs are reasonable and fair for all regional consumers.

After a dearth of transmission system upgrades during the pre-market era, New England states have successfully sited four of six major 345-kilovolt transmission projects needed to reinforce the entire region's transmission system. These sited projects represent more than 60 percent of the total amount needed in transmission investment in New England. ISO New England commits considerable resources to provide additional studies and expert testimony at the state siting level as part of its increased responsibility for regional planning, which ensures that regional system needs are met as demand continues to grow.



Strengthened Oversight and Governance Promise Benefits into the Future

Regional Transmission Organizations

After the independent system operators were launched, mainly during the 1990s, FERC refined the concept of independent oversight by promoting the adoption of “regional transmission organizations” (RTOs). These large multi-state entities are intended to oversee integrated, regional bulk power transmission service, broader regional system planning and larger electricity trading markets—all while having clear authority for grid operation that protects reliability and promotes efficiency.

An RTO for New England

On February 1, 2005, ISO New England became a regional transmission organization. While it continues to perform existing responsibilities, it also has become the region’s transmission provider. Its designation as an RTO provides essential clarification of its roles and responsibilities and those of the region’s stakeholders. Operating as an RTO also strengthens ISO New England’s independence, while ensuring that stakeholders continue to have a high degree of input.

Improved Authority for Reliability

As an RTO, ISO New England now has clear operational control over the day-to-day management of the region’s transmission facilities; authority for the terms and conditions by which transmission customers receive non-discriminatory transmission service; and the ability to require transmission owners to pursue needed upgrades. ISO New England will continue to be the single point of control to maintain reliability, not only on a daily basis, but also in emergencies. Through these authorities, it has increased ability to protect the region from system failures.

Strengthened Independence for Market Efficiency

Evolution to an RTO structure has significantly strengthened ISO New England’s independence. As an RTO, it has authority to develop and propose new market rules, instead of the financially interested market participants who previously had this responsibility. Under the new RTO process, ISO New England is committed to a fair and open stakeholder process that allows alternative proposals for new market rules to receive equal consideration.

Enhanced Responsiveness to Stakeholders

ISO New England is independent of market interests and is ultimately accountable to FERC. However, its success depends heavily on its coordination with New England state officials and its responsiveness to market participants. The RTO structure will enhance these qualities. Notably, ISO New England Board members will be elected with input from a nominating committee that includes representatives of market participants and regulators and after an advisory voting process through the New England Power Pool Participants Committee.

Greater Interregional Coordination

Significant reliability and efficiency benefits can be realized by allowing access to the broadest set of resources, without having to duplicate resources. The New England region is particularly well situated to beneift from fuel diversity in New York and any surplus supplies available in Canada during the summer months.

As an RTO, ISO New England will have greater authority for interregional planning and will implement initiatives and arrangements with neighboring power systems that effectively broaden the marketplace and its offerings for New England consumers. Benefits include:

- Strengthened reliability created by access to a broader, more diverse set of resources
- Elimination of transaction fees between New England and New York that prevent the most efficient dispatch of resources
- Identification of needs and solutions to enhance overall reliability and efficiency of the combined New England, New York and Mid-Atlantic regions

Cost-Effective Operations

ISO New England has taken on a variety of additional and significant tasks for the benefit of consumers and an ever-increasing number of market participants, requiring growth in the small staff with which it began operations. These additional tasks—system, markets and interregional planning; demand response program administration; operational control over transmission facilities; and independent market rules development—were pursued after consulting with the market participants and state regulators and under the direction and approval of FERC. ISO New England has focused on cost containment, consistent with the quality performance of its expanded duties. As a result, the New England region is the beneficiary of a full-service system operator that provides a high level of electric service reliability, market efficiency and consumer protection with one of the lowest annual operating budgets of any ISO or RTO in North America. ISO New England services are estimated to cost the average retail consumer only sixty cents per month.

Into the Future

The innovation, responsiveness and cost-effectiveness that ISO New England and other ISOs and RTOs are bringing to their operations carries on the evolution of the electric power industry that began more than a decade ago. During the coming years, ISO New England will continue to refine the model of competitive markets that have revolutionized a once-slumbering industry, with greater reliability, efficiency and consumer benefits.

2004
Year in Review

Jan 14-16 New England's power system and markets operate reliably despite combination of extreme cold, unexpected number of power plant outages, and record high electricity and natural gas use during bitterly cold weather.

March 1 First anniversary of Standard Market Design in New England finds SMD provides economic and reliability benefits for the region.

March 1 Proposal with FERC filed to institute LICAP, designed to appropriately value existing power supplies and incent investment in new resources in needed locations.

March 24 FERC conditionally approves ISO New England's regulatory designation as an RTO.

May 10 Interim January Cold Snap Report released; recommendations, based on operational experience gained during the cold snap, lead to a stronger system.

June Report by U.S. Department of Energy and the Edison Electric Institute recognizes ISO New England's annual system planning process as a national model.

July 15 Publish first weekly billing statement to customers; monthly settlements were previously standard.

July 29 In response to the August 2003 Northeast Blackout, North American Electric Reliability Council audit identifies 10 ISO New England 'best practices' for the industry.

Sept 30 Board of Directors approves 2005 Wholesale Markets Plan; identifies the timing and scope of planned enhancements to New England's wholesale electricity markets.

Oct 12 Customer Asset Management System launched to provide streamlined and more efficient data management for customers and ISO New England.

Oct 21 Board of Directors approves 2004 Regional Transmission Expansion Plan; identifies present and future system investment needed to reliably serve the region and its economy for years to come.

Oct 31 New York Mercantile Exchange opens trading of electricity futures based on ISO New England's wholesale electricity marketplace; underscores the stable trading environment and long-term confidence in the region's markets.

Nov 23 First long-term (12-month) Financial Transmission Rights auction opens for Jan 1–Dec 31, 2005.

Dec 10 First Statement on Auditing Standards (SAS) 70 Type 2 Audit passed; provides unqualified opinion and another level of assurance that SMD controls, systems and processes operate effectively.

Dec 20 Report to Connecticut Siting Council issued; offers solution to Southwest Connecticut transmission needs that balances the state's interest in placing lines underground with the physical realities of reliable and responsible bulk power system operation.

Dec 21 Release of Version 3.0 of Enhanced Energy Scheduler (EES) software used for submitting day-ahead and real-time external transactions.

Dec 30 ISO New England declares February 1, 2005, the operation date for RTO implementation, thereby strengthening the independent and efficient management of the region's bulk electric power system and competitive wholesale electricity markets.

Report of Independent Auditors

To the Board of Directors and Members of ISO New England Inc.:

In our opinion, the accompanying statements of financial position and the related statements of activities and of cash flows present fairly, in all material respects, the financial position of ISO New England Inc., at December 31, 2004 and 2003, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

PriceWaterhouseCoopers LLP
Boston, Massachusetts

March 22, 2005

Statements of Financial Position
For Years Ended December 31, 2004 and 2003

		2004		2003
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$	40,562	$	45,329
Security deposits		67,643		137,482
Unbilled receivable, net		21,147		19,350
Prepaid expenses		606		142
Restricted cash on deposit		17,774		42,128
Noncurrent assets:				
Property and equipment in-service, net (Note 3)		52,667		78,625
Work in process (Note 3)		22,164		4,839
Deferred charges		364		834
Swap asset (Note 4)		156		-
Regulatory asset		1,504		2,222
Total assets	$	224,587	$	330,951
Liabilities and Net Assets				
Current liabilities:				
Accounts payable:				
Settlement, net	$	26,151	$	493
Administration		7,878		8,405
Deposits payable		68,249		138,302
Interest payable		887		292
Billing advance collections		-		20,643
Accrued expenses		7,782		6,713
Minimum pension liability (Note 5)		1,504		1,988
Swap liability (Note 4)		-		234
Regulatory liability		156		-
Deferred income - current		13,995		71
Restricted cash on deposit payable		17,774		42,128
Term loan payable-current (Note 4)		21,687		35,421
Long-term liabilities:				
Deferred income, net of current portion		2,357		9,783
Term loan, net of current portion (Note 4)		56,167		66,478
Total liabilities		224,587		330,951
Unrestricted net assets		-		-
Total liabilities and net assets	$	224,587	$	330,951

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

Statements of Activities
For Years Ended December 31, 2004 and 2003

	2004	2003
	(In thousands)	
Changes in unrestricted net assets:		
Revenues (Note 1):		
ISO tariff revenues	$ 115,262	$ 100,942
Interest income	462	504
Fees and services	1,117	1,478
Total unrestricted revenues	116,841	102,924
Expenses:		
General and administrative:		
Salaries and benefits	46,310	41,417
Professional and consultants	16,783	12,441
Rents and leases	2,509	2,850
Computer services	3,684	3,831
Depreciation and amortization expense	35,227	31,908
Communication expense	1,586	2,007
Interest expense	2,561	3,066
Other	8,181	5,404
Total expenses	116,841	102,924
Change in unrestricted net assets	-	-
Unrestricted net assets, beginning of year	-	-
Unrestricted net assets, end of year	$ -	$ -

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

Statements of Cash Flows
For Years Ended December 31, 2004 and 2003

	2004	2003
	(In thousands)	
Cash flows from operating activities:		
Increase in unrestricted net assets	$ -	$ -
Adjustments to reconcile change in unrestricted net assets to net cash provided by operating activities:		
Depreciation expense	34,481	28,802
Loss on disposal of asset	1,024	51
(Increase) in accounts receivable	(1,797)	(8,557)
Decrease in deferred charges	470	2,767
(Increase) in prepaid expense	(464)	(70)
Decrease in regulatory asset	718	296
(Increase) swap asset	(156)	-
Increase/(decrease) in accounts payable:		
Settlement	25,658	(118)
Administration	(4,132)	(4,748)
(Decrease) in daily billing advance collections	(20,643)	(32,533)
(Decrease) in accrued pension and postretirement benefits	-	(1,866)
(Decrease) in minimum pension liability	(484)	(530)
Increase/(decrease) in swap liability	(234)	234
Increase regulatory liability	156	-
Increase in accrued expenses	1,069	1,002
Increase in interest payable	595	163
Increase in deferred income	6,498	9,338
Net cash provided/(used) by operating activities	42,759	(5,769)
Cash flows from investing activities:		
Capital expenditures	(23,267)	(17,382)
Net cash used in investing activities	(23,267)	(17,382)
Cash flows from financing activities:		
Decrease in security deposits	69,839	6,149
(Increase)/decrease in restricted cash on deposit	24,354	(40,517)
Increase/(decrease) in restricted cash on deposit payable	(24,354)	40,517
(Decrease) in deposits payable	(70,053)	(6,087)
Proceeds from term loan	9,450	27,050
Repayment on term loan	(72,495)	(16,151)
Proceeds from private placement debt	39,000	-
Repayment on revolving credit, net	-	(5,000)
Net cash provided/(used) by financing activities	(24,259)	5,961
Net decrease in cash and cash equivalents	(4,767)	(17,190)
Cash and cash equivalents, beginning of year	45,329	62,519
Cash and cash equivalents, end of year	$ 40,562	$ 45,329
Supplemental data:		
Amounts included in Accounts Payable and Accrued expenses related to work in process	$ 3,605	$ 2,663
Cash paid during the year for interest	$ 2,671	$ 3,258

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

Notes to Financial Statements

1. Summary of Significant Accounting Policies

Description of Business
ISO New England Inc. (the "Company" or "ISO") commenced operations on July 1, 1997 as the New England electric transmission independent system operator for the New England Power Pool ("NEPOOL") in compliance with the requirements of the Federal Energy Regulatory Commission ("FERC"). On May 1, 1999, the competitive marketplace opened in the ISO New England control area. The Company administers NEPOOL's open-access transmission tariff, administers a power exchange, and maintains the short-term reliability of the bulk power system.

Cash Equivalents
The Company considers cash on hand and short-term marketable securities with original maturities of three months or less to be cash equivalents. The cash equivalents at December 31, 2004 and 2003 were held in overnight repurchase agreements and also in direct and indirect obligations of the United States.

Accounts Receivable and Accounts Payable
In the course of bulk power transactions administered by the Company on behalf of the NEPOOL Participants, amounts for energy purchased and sold among Participants become payable to and receivable from such Participants. The Company summarizes and prices the energy transactions each week and provides an invoice or remittance advice to each Participant that summarizes the amount either payable to or receivable from each Participant.

Accounts payable on the balance sheet are segregated between the amounts owed for energy transactions and transmission, for which the ISO functions as paying agent, and for the administrative expenses incurred by the Company in the course of operations.

The net unbilled receivables at the end of each week include those amounts that will be billed and included in the invoice or remittance advice to Participants in the subsequent week. The net payables and receivables for energy transactions are settled with the Participants in the subsequent week.

Restricted Cash on Deposit
The balance of $17.8 million and $42.1 million in 2004 and 2003, respectively, recorded as Restricted Cash on Deposit represents the Congestion Revenue Fund, NRG Cost of Service Agreement Escrow and Pre-petition funds, which are restricted by Market Rule 1, FERC Orders or Bankruptcy Law. The balance is offset by a liability on the Statement of Financial Position. The restricted cash on deposit at December 31, 2004 and 2003 were held in overnight repurchase agreements and also in direct and indirect obligations of the United States.

Property and Equipment
The Interim Independent System Operator Agreement between the Company and NEPOOL states that any fixed assets acquired or developed by the Company and funded by the NEPOOL Participants shall be the property of the NEPOOL Participants. All capital expenditures of the Company subsequent to January 1, 2000 have been funded by the Company, principally through bank borrowings, and the assets acquired or developed have been recorded in Property and Equipment. Property and equipment is stated at cost, net of accumulated depreciation.

The Company applies the provisions of Statement of Financial Accounting Standards No. 34, "Capitalization of Interest Costs" ("FAS 34") and Statement of Financial Accounting Standards No. 62, "Capitalization of Interest Costs in situations involving certain tax-exempt borrowings and certain gifts and grants, an amendment of FASB Statement No. 34", which requires the Company to capitalize the interest and fees associated with the borrowings that the Company has entered into for the acquisition of assets related to a project that has a material effect on the Company's financial position.

In addition, the Company follows the provision of the Statement of Position 98-1, "Accounting for the Costs of Computer Service Software Development" ("SOP 98-1") in capitalizing internal software development costs.

Depreciation
Depreciation is generally computed using straight-line methods over an estimated useful life ranging from three years to twenty-five years (computer hardware, software and accessories—3 to 5 years, software development costs—3 to 5 years, capitalized interest and fees—3 to 5 years, furniture and fixtures—7 years, leasehold improvements—10 years or

remaining useful life whichever is shorter, vehicles—3 years, building—25 years). No depreciation is recorded for assets classified in work in process (Note 3). Depreciation expense is offset by amortization of Deferred Income related to fixed assets the Company purchased and placed in service in 1997 through 1999 that were pre-funded by NEPOOL Participants.

Derivative Policy

The Company follows the provisions of Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities” (“FASB 133”), as amended by FAS 138, in establishing its derivative policy. The policy states that the Company’s Management will make the determination with the approval of the Company’s Audit and Finance Committee to enter into fixed interest rate swaps when the fixed interest rate offered at the time will outweigh the risk of leaving the term loan borrowings to the fluctuations of the market, taking into consideration the length of the term loan, the state of the economy and the direction the Management team believes the economy is moving.

Deferred Charges and Regulatory Assets/Liabilities

The Company applies the provisions of Statement of Financial Accounting Standards No. 71, “Accounting for the Effects of Certain Types of Regulation” (“FAS 71”), which requires regulated entities, in appropriate circumstances, to establish regulatory assets or liabilities, and thereby defer the income statement impact of certain charges or revenues because it is probable to be collected or refunded through future customer billings. During 2002, in response to a FERC Ruling, all post September 11, 2001 security enhancement costs incurred above and beyond the amount filed in the ISO Tariff for 2002 were allowed to be capitalized and recovered in future ISO Tariff filings. Additionally, ISO New England incurred pension cost and the purchase of land located at Sullivan Road, which were not included in the 2003 and 2004 ISO Tariff rates, respectively. These costs were deferred and will be collected in future ISO Tariff filings.

Deferred Charges	**2004**	**2003**
Post September 11, 2001 security enhancement costs	-	324,000
Pension costs	213,000	510,000
Land located on Sullivan Road	151,000	-
	$ 364,000	$ 834,000

Regulatory Assets	**2004**	**2003**
Minimum pension liability	1,504,000	1,988,000
Swap liability	-	234,000
	$ 1,504,000	$ 2,222,000

Regulatory Liability	**2004**	**2003**
Swap asset	156,000	-
	$ 156,000	-

Income Taxes

Income taxes, for both Federal and State of Massachusetts, are not provided by the Company because it is operating as a corporation described in Section 501(c)(43) effective November 10, 2004, and was previously operating as a corporation described in Section 501(c)(4) of the Internal Revenue Code, and is exempt under Section 501(a) of the Internal Revenue Code. The Company has no unrelated business tax.

Security Deposits

The NEPOOL Participants are required to comply with the NEPOOL Financial Assurance Policy. In the case of non-investment grade rated Participants that meet certain criteria, the NEPOOL Financial Assurance Policy requires these Participants to put in place alternate forms of financial assurance. There are several options allowed under the NEPOOL Financial Assurance Policy for compliance, one of which is to post cash as collateral. The cash collateral deposits at December 31, 2004 and 2003 were approximately $67,643,000 and $137,482,000, respectively.

Billing Advance Collections
In 2002, the ISO, NEPOOL, and a certain Participant entered into a Weekly Billing Agreement, which continued into 2003. The Weekly Billing Agreement required the ISO to issue an invoice weekly to the affected Participant, who was required to pay the invoice on a weekly basis, which represented the amount of estimated charges they had incurred for the week. The amounts collected in advance were then trued-up at the end of each month through the normal settlement billing process. There were no such agreements in place in 2004.

Revenue Recognition
The Company recovers its operating and debt service costs pursuant to the ISO Tariff, which provides for recovery of expenses through three schedules. Scheduling, System Control and Dispatch Service (Schedule 1), Energy Administration Service (Schedule 2) and Reliability Administration Service (Schedule 3) recover related cost through a pre-approved rate applied to each month's activity. Schedules 1, 2 and 3 are subject to true-up through subsequent years' rates, and any over or under collection is recorded as deferred charges or deferred income. Schedule 2 of the 2004 ISO Tariff has been redesigned to include an additional basis for recovery. The basis for this recovery is a per transaction charge for increment offers and decrement bids submitted into the Day-Ahead Market.

Deferred Income
Deferred income offsets the net fixed assets of the Company that were purchased and placed in service in 1997 and 1998, and the amount of the ISO Tariff for Schedules 1, 2, and 3 that was over/under collected from 1999 through 2004. The pre-funded fixed-asset deferred income is being amortized to income over the life of the assets at the rate depreciation is recognized. In addition, the over/under collection amount of the ISO Tariff will be returned to the Participants through the mechanism provided for within the ISO Tariff.

Postretirement Benefit Plan
The Financial Accounting Standards Board ("FASB") issued FASB Staff Position 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" ("FSP106-2"), which is effective December 31, 2004 for the Company.

The Company has evaluated the effects of FSP 106-2 on the accumulated postretirement benefit obligation and the net periodic postretirement benefit cost, and determined the impact of this is immaterial.

Concentrations
The Company's top 10 Participants represented approximately 55% or $67.2 million and 56% or $61.4 million in tariff revenues for the years ended 2004 and 2003, respectively.

Fair Values of Financial Instruments
The carrying amounts reported in the Statement of Financial Position for current assets and liabilities approximate their fair values.

Use of Estimates
Generally accepted accounting principles require Management to make estimates and assumptions that affect assets and liabilities, contingent assets and liabilities, and revenues and expenses. Actual results could differ from those estimates.

Liquidity Information
In order to provide information about liquidity, assets have been sequenced according to their nearness to conversion to cash, and liabilities have been sequenced according to the nearness of their resulting use of cash.

Reclassification
Certain amounts on the financial statements of the prior year have been reclassified to conform with the current year's basis of presentation.

2. Commitments and Contingencies

Funding Arrangements

The Company has incurred significant expenses on behalf of NEPOOL relating to the development of NEPOOL's interim wholesale electric market that was placed in service May 1, 1999 for New England and the formation of the Company (implementation costs). Additional costs were incurred by NEPOOL itself. The final project costs were $50,567,000, exclusive of interest.

In accordance with the fortieth amendment to the NEPOOL Agreement, the Company has begun administering repayment of these costs by the current NEPOOL membership, which includes members that originally funded the expenses if they are still active Participants, to the members that originally funded the expenses. The repayment is to be made over a five-year period to the funding Participants at an interest rate of 8% per annum until August 18, 2001 and 10.78% per annum thereafter, beginning May 1, 1999. The source of repayment was a monthly charge to NEPOOL Participants based on their pro rata share of ISO Schedule 2 costs, which expired January 1, 2001.

Beginning January 1, 2001, the source of repayment for the remaining amounts is based 50% on Participants' pro rata share of electrical load and generating shares and 50% on Participants' pro rata share of electrical load and generating share peaks as defined in the Restated NEPOOL Agreement. The amount of these costs to be repaid by the current NEPOOL membership to the members that originally funded the expenses was approximately $0 and $4,482,000 at December 31, 2004 and 2003, respectively.

Capital Funding Tariff

The FERC accepted ISO's "capital funding tariff" ("CFT") filing for 2004 and 2003. These filings support the ISO's loan arrangements with various banks and note holders to fund the capital and working capital requirements of the Company.

Legal Proceedings

The Company is party to various legal actions incident to its business; however, Management believes that no material awards against the Company will result from such proceedings.

In accordance with the revised NEPOOL Billing Policy, formal billing disputes of Participants are not held in escrow until the dispute is resolved. The billing disputes total approximately $7,418,000 and $4,950,000 at December 31, 2004 and 2003, respectively. Settled disputes are paid by the Participants.

3. Property and Equipment In-Service, net and Work in Process

	December 31, 2004	December 31, 2003
Computer hardware, software and accessories	$ 91,313,000	$ 89,509,000
Software development costs	21,528,000	20,195,000
Furniture and fixtures	853,000	839,000
Building and leasehold improvements	6,163,000	3,537,000
Capitalized interest and fees	3,885,000	3,843,000
Vehicles	75,000	75,000
	123,817,000	117,998,000
Less: accumulated depreciation and amortization	(71,150,000)	(39,373,000)
Property and equipment in-service, net	$ 52,667,000	$ 78,625,000
Work in process	$ 22,164,000	$ 4,839,000

There were a number of new projects as of 2004, such as the ancillary service market project, web redesign and various market enhancement projects, which have not been placed in service as of December 31, 2004. Interest capitalized as work in process in 2004 and 2003 was $508,000 and $0, respectively.

Implementation of the Standard Market Design software system ("SMD") in 2003 necessitated the Company's disposal of assets related to the interim markets software system. This asset disposal resulted in a loss of $1,024,000 in 2004, and is reflected in "other" on the accompanying Statements of Activities.

4. Credit Facilities

Revolving Credit Arrangement

In June 2001, the Company entered into a $15 million revolving credit arrangement which expired in 2004. The Company entered into a new $15 million revolving credit arrangement in June 2004. The outstanding balances at December 31, 2004 and 2003 were $0. Interest accrues on the revolving credit at a London Inter-bank Offering Rate ("LIBOR") of which the Company has the option of selecting the 30, 60, 90, or 180-day rate, plus a .60% spread. Interest is paid at the earlier of the selected LIBOR term or 30 days. The arrangement expires June 1, 2009 and any outstanding balance must be paid by this date. The Company is charged an annual fee of .15% on the entire line of credit. The weighted average interest rate incurred for the years ended December 31, 2004 and 2003 was 0% and 2.37%, respectively.

In June 2004, the Company also entered into a $4.0 million revolving credit arrangement, which was requested as a result of the change in the NEPOOL billing policy to go from monthly billing to weekly billing. This arrangement serves as a line of credit to cover any potential payment defaults by a Participant. Interest accrues on the revolving credit at a LIBOR of which the Company has the option of selecting the 30, 60, 90 or 180-day rate, plus a .60% spread. Interest is paid at the earlier of the selected LIBOR term or 30 days. The arrangement expires July 1, 2009 and any unpaid balances must be paid as of this date. The Company is charged an annual fee of .15% on the entire line of credit. The weighted average interest rate for the year ended December 31, 2004 was 0%.

Term Loan and Private Placement Debt Arrangement

The Company entered into a $43.0 million term loan in 2001, a $40.0 million term loan in 2002, a $24.5 million, and a $20.0 million term loan in 2003. Principal is payable monthly with the final repayments due between June 2006 and June 2007. The Company also entered into a $39.0 million private placement loan which is made up of ten 5.60% senior notes. Payment is due in full on September 2, 2014, with no mandatory prepayments. The total outstanding debt at December 31, 2004 and 2003 was $77.9 million and $101.9 million, respectively. Interest accrues on the $20.0 and $24.5 million term loans at LIBOR of which the Company has the option of selecting the 30, 60, 90 or 180-day rate, plus a 1.375% spread.

The Company has entered into interest rate exchange agreements to mitigate the interest rate risks associated with its floating-rate term loans. On March 17, 2003, the Company entered into three interest rate exchange agreements whereby the Company pays at a fixed interest rate for predetermined notional amounts as scheduled at the time of execution of the agreements. The first interest rate exchange agreement for $43.0 million is effective March 17, 2003 to June 1, 2006. The notional amount of this agreement at December 31, 2004 is $21.5 million with a fixed rate of 3.375%. The second interest rate exchange agreement for $40.0 million, which was effective March 17, 2003 to January 1, 2007 with a fixed interest rate of 3.555%, was terminated in July of 2004 and resulted in a net gain of $206,657 to the ISO, which is reflected as a reduction of interest expense, in the accompanying Statement of Activities. The third interest rate exchange agreement for $24.5 million which was effective March 17, 2003 to June 30, 2006 with a fixed interest rate of 3.455%, was terminated in July 2004 and resulted in a net gain of $73,998 to the ISO, which is also reflected in the accompanying Statement of Activities. For the years ended December 31, 2004 and 2003, the weighted average floating interest rate is approximately 3.21% and 3.31%, respectively.

The fair market value of the out-of-market interest rate swaps as of December 31, 2004 and 2003 was $156,000 and ($234,000), respectively. The fair-market values are derived from proprietary models. The offset is recorded as a liability on the Statement of Financial Position.

Principal payments on the term loan and private placement debt are due annually as follows:

2005	$	21,687,000
2006		13,833,000
2007		3,334,000
2008		-
2009		-
Thereafter		39,000,000
	$	77,854,000

These credit agreements contain both affirmative and negative covenants, the most restrictive of which is the maintenance of a financial ratio related to revenue and expense-plus-debt service. The Company was in compliance with these ratios at December 31, 2004 and 2003.

Interest incurred on the revolving credit and the term loans for the years ended December 31, 2004 and 2003 was approximately $3,259,000 and $3,421,000, respectively. Interest capitalized from the term loans for the years ended December 31, 2004 and 2003 was approximately $508,000 and $355,000, respectively.

5. Pension and Other Employee Benefits

The Company sponsors defined benefit pension and postretirement plans, which cover substantially all union and nonunion employees and provide retirement income, medical, dental and life insurance benefits.

The Company sponsors two defined benefit pension plans, which are funded solely by Company contributions. Benefits are determined based on years of service and average compensation.

The Company sponsors two defined benefit postretirement plans, which provide medical, dental and life insurance benefits for union and nonunion eligible employees and their beneficiaries. The medical benefits are contributory with participants' contributions adjusted annually and participants are responsible for deductible and coinsurance amounts. Dental benefits are noncontributory but participants are responsible for deductible and coinsurance amounts. The life insurance benefits are noncontributory.

	Pension Benefits Years Ended December 31,		Other Postretirement Benefits Years Ended December 31,	
	2004	2003	2004	2003
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 34,493,000	$ 27,390,000	$ 2,786,000	$ 2,461,000
Service cost	2,536,000	2,102,000	427,000	380,000
Interest cost	2,064,000	1,851,000	161,000	153,000
Benefits paid	(560,000)	(329,000)	(43,000)	(33,000)
Plan participants' contributions	-	-	6,000	5,000
Actuarial (gain) loss	1,803,000	3,479,000	-	(180,000)
Benefit obligation at end of year	40,336,000	34,493,000	3,337,000	2,786,000
Change in plan assets:				
Fair value of plan assets at beginning of year	24,360,000	17,078,000	2,674,000	-
Actual return on plan assets	2,908,000	4,535,000	305,000	227,000
Employer contributions	3,139,000	3,076,000	417,000	2,475,000
Plan participants' contributions	-	-	6,000	5,000
Benefits paid	(560,000)	(329,000)	(43,000)	(33,000)
Fair value of plan assets at end of year	29,847,000	24,360,000	3,359,000	2,674,000
Funded status	(10,489,000)	(10,133,000)	22,000	(112,000)
Unrecognized transition obligation	1,187,000	1,312,000	697,000	753,000
Unrecognized net actuarial (gain) loss	9,268,000	8,785,000	(904,000)	(876,000)
Unrecognized prior service cost	34,000	36,000	185,000	235,000
Prepaid (accrued) benefit cost	$ -	$ -	$ -	$ -

Amounts recognized in the statement of financial position consist of:

	Pension Benefits		Other Benefits	
	12/31/2004	12/31/2003	12/31/2004	12/31/2003
(Accrued) benefit cost	$ (1,504,000)	$ (1,988,000)	-	-
Regulatory assets	1,504,000	1,988,000	-	-
Net amount recognized	-	-	-	-

The accumulated benefit obligation for all defined benefit pension plans was $30,791,000 and $25,906,000 at December 31, 2004 and 2003, respectively.

	December 31, 2004	December 31, 2003
Projected benefit obligation	$ 40,336,000	$ 34,493,000
Accumulated benefit obligation	$ 30,791,000	$ 25,906,000
Fair value of plan assets	$ 29,847,000	$ 24,360,000

The Company follows the provisions of Statement of Financial Accounting Standards No. 87; Employers' Accounting for Pensions, and Financial Accounting Standards No. 132; Employers' Disclosures about Pensions; and other Post Retirement Benefits, in determining the minimum liability requirements. A liability has been recorded on the Statements of Financial Position in the amount of $1,504,000 and $1,988,000 for the years ended December 31, 2004 and December 31, 2003, respectively. The accumulated benefit obligation exceeded the fair value of plan assets for one defined benefit plan, which was in an under funded position, as follows:

	December 31, 2004	December 31, 2003
Accumulated benefit obligation	$ 29,506,000	$ 24,621,000
Fair value of plan assets	28,433,000	22,955,000
Prepaid benefit cost	431,000	322,000
Minimum pension liability	$ 1,504,000	$ 1,988,000

The Company has determined that this amount is probable of recovery through the ISO Tariff and has recorded a regulatory asset at December 31, 2004 and December 31, 2003.

	Pension Benefits Years Ended December 31,		**Other Postretirement Benefits Years Ended December 31,**	
	2004	**2003**	**2004**	**2003**
Components of net periodic benefit cost:				
Service cost	$ 2,536,000	$ 2,102,000	$ 426,000	$ 379,000
Interest cost	2,064,000	1,851,000	161,000	153,000
Expected return on plan assets	(1,947,000)	(1,462,000)	(213,000)	-
Amortization of transition obligation	125,000	125,000	56,000	56,000
Amortization of net actuarial loss	359,000	458,000	-	-
Amortization of unrecognized prior service	2,000	2,000	51,000	51,000
Amortization of unrecognized (gain)/loss	-	-	(64,000)	(30,000)
Net periodic benefit cost	$ 3,139,000	$ 3,076,000	$ 417,000	$ 609,000

The primary economic assumptions used to value these liabilities are summarized in the following chart. These assumptions are selected as the measurement data based on prevailing economic conditions.

Weighted-average assumptions used to determine net periodic benefit cost for the following years ended:

	Pension Benefits Years Ended December 31,		**Other Benefits Years Ended December 31,**	
	2004	**2003**	**2004**	**2003**
Discount rate	6.00%	6.50%	6.00%	6.50%
Expected long-term rate of return on plan assets	7.50%	8.00%	7.50%	N/A
Rate of compensation increase	3.50%	4.00%	3.50%	4.00%
Health-care cost trend rates – initial	-	-	7.00%	9.00%
Health-care cost trend rates – ultimate	-	-	4.00%	4.00%
Ultimate year	-	-	2007	2007

Weighted-average assumptions used to determine benefit obligation for the following years ended:

	Pension Benefits Years Ended December 31, 2004	2003	Other Benefits Years Ended December 31, 2004	2003
Discount rate	5.75%	6.00%	5.75%	6.00%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%

A one percentage point change in the assumed health-care cost trend rates would increase the Accumulated Post Retirement Benefit (APBO) as of December 31, 2004 by approximately $150,000 or decrease the APBO by approximately $134,000. Additionally, a one percentage change in the assumed health care cost trend rates would increase or decrease the net post retirement cost for 2004 by approximately $34,000 and $31,000, respectively.

ISO's pension plan weighted-average asset allocations and expected returns by asset category are as follows:

Pension Plan Assets

	Target Allocation 2005	Percentage of Plan Assets at December 31 2004	2003	Weighted Average Expected Long-Term Rate of Return - 2004
Equity securities	60%	65%	61%	5.50%
Debt securities	40%	35%	39%	2.00%
Total	100%	100%	100%	7.50%

ISO's postretirement benefit plan weighted-average asset allocations and expected returns by asset category are as follows:

Postretirement Plan Assets

	Target Allocation 2005	Percentage of Plan Assets at December 31 2004	2003	Weighted Average Expected Long-Term Rate of Return - 2004
Equity securities	60%	65%	61%	5.50%
Debt securities	40%	35%	39%	2.00%
Total	100%	100%	100%	7.50%

The forward-looking estimates of total return are generated through combined assessment of current valuation measures, income, economic growth and inflation forecasts, and historical risk premiums. The long-term bond forecast is derived from the expected long-term return of a portfolio of corporate, government and high-yield debt instruments. The equity forecasts are based on the long-term real returns of a portfolio of U.S. large cap, U.S. small cap, international developed markets and emerging markets equity securities.

The Plan's investment portfolio is to be invested to provide benefits for qualified employees of ISO New England. Investments are to be compatible with the liquidity requirements determined by the plan's actuary. An optimal target allocation of 60/40 between equities and fixed-income investments is to be kept with an allowance of 15% over/under deviation from the optimal allocation target.

The Company expects to contribute $3,599,000 to its pension plan and $484,000 to its postretirement benefit plan in 2005.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Other Benefits
2005	$ 519,000	$ 85,000
2006	$ 609,000	$ 109,000
2007	$ 746,000	$ 138,000
2008	$ 933,000	$ 165,000
2009	$ 1,129,000	$ 217,000
Years 2010-2014	$ 10,380,000	$ 2,338,000
Total	$ 14,316,000	$ 3,052,000

6. 401(k) Savings Plan

The Company has a 401(k) Retirement and Savings Plan open to substantially all employees. This savings plan provides for employee contributions up to specified limits. The Company matches employee contributions up to 3% of eligible compensation and provides a 50% match on the next 2% of eligible compensation. The matching contributions for the Company were $1,131,000 and $976,000 for 2004 and 2003, respectively.

7. Leases

The following is a schedule by year of future minimum rental payments for all noncancelable operating leases:

2005	$ 906,000
2005	853,000
2007	496,000
Total minimum lease payments	$ 2,255,000

The Company currently houses its back-up facilities at a separate location for a minimum annual payment. In April 2002, the Company secured additional space at the same facility.

Additionally, the Company leases office space in one other building. The additional office space is leased with an initial term of six years with an automatic month-to-month renewal option.

For fiscal years 2004 and 2003, actual rental payments for operating leases were $2,277,000 and $2,191,000, respectively.

As part of a separation agreement with NUSCO, the Company has agreed to reimburse NUSCO for all charges related to providing service to NEPOOL. This includes charges for leased equipment used at the Control Center. The lease was terminated in 2004 and all outstanding balances were paid. The annual payments were approximately $120,000 and $534,000 for the years 2004 and 2003, respectively.

8. Expiration of ISO Interim Agreement

The Company operates under an Interim ISO Agreement with NEPOOL, which was scheduled to expire on December 31, 2004. The Company and NEPOOL agreed to extend this agreement through April 1, 2005 or the effective date of operation as a Regional Transmission Organization (RTO), whatever comes earlier. Subsequently, the Company filed a Notice of Operations date with the FERC, which stated the Company would operate as a RTO effective February 1, 2005. As of February 1, 2005 the Company is operating as an RTO.

9. Subsequent Events

Regional Transmission Organization

On March 24, 2004 FERC conditionally approved the implementation of an RTO in New England. Throughout 2004, the ISO made a number of filings with the FERC to comply with the conditions imposed by the FERC. On December 30, 2004, the ISO and the New England transmission owners filed a notice of a February 1, 2005 Operations Date for the RTO. On February 1, 2005, the ISO became the RTO for New England, with enhanced responsibilities as the transmission provider for New England and new governing documents (Transmission Operating Agreement, Participants Agreement, Market Participants Service Agreement, ISO New England Transmission, Markets and Services Tariff) in place of the existing governing documents (the Interim ISO Agreement, NEPOOL Tariff). It is anticipated that the ISO will experience an increase in legal costs as a result of taking over the responsibility of making the FERC filings. All anticipated increased costs as a result of becoming the RTO were included in the revenue requirements of the 2005 Administrative Cost of Services Tariff filing with the FERC.

Tax Exempt Financing

In February of 2005 the Company obtained tax-exempt financing of $45,500,000 in the form of Multi-Mode Variable Rate Civic Facility Revenue Bonds, which were issued by the Massachusetts Development Finance Agency. The proceeds of the Bonds were loaned to the Company to assist in financing and refinancing a project located at the main control center. The project will entail the acquisition of a 13-acre parcel of property and attached existing 64,000-square-foot facility (which acquisition took place in December 2004); the renovation, equipping and furnishing of the existing facility, including construction of a 3,200-square-foot expansion, a new lobby and mechanical penthouses; construction, equipping and furnishing of a three-story, 100,000-square-foot facility; and construction of site improvements, including but not limited to additional parking spaces, a retaining wall and security curtain, a pedestrian connecting bridge between the existing and new facilities and a guard house. The project is expected to take up to 18 months to complete.

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(as of September 2004)

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New England by the Numbers

- 6.5 million households and businesses; population 14 million
- More than 350 generators
- Over 8,000 miles of high-voltage transmission lines
- 12 interconnections to electricity systems in New York and Canada
- More than 31,000 megawatts of total supply
- All-time peak demand of 25,348 megawatts (August 14, 2002)
- More than 260 participants in the marketplace (those who generate, buy, sell, transport and use wholesale electricity)
- $7.25 billion annual total energy market value
- Up to $4.0 billion in transmission expansion needed over next 10 years; four of six major 345-kilovolt projects already approved by state siting councils

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