June 12, 2013

VIA EMAIL

Hon. Jeffrey Cohen
Acting Secretary to the Commission
New York State Public Service Commission
Empire State Plaza
Agency Building 3
Albany, NY 12223-1350

Re: Contingency Procurement of Generation and Transmission, Inquiry #Q13-5441LW

Dear Secretary Cohen,

Iberdrola USA is pleased to submit our proposal for Connect New York HVDC Project, a new 53.3 mile transmission line, as a response to your Request for Proposal entitled "Contingency Procurement of Generation and Transmission, Inquiry #Q13-5441LW."

This package includes one hard copy and one CD copy. We have also emailed a PDF version of this proposal to you.

If you have any questions, please contact me anytime at (207) 688-6362. Thank you for your consideration for this exciting project!

Yours sincerely,

Thorn Dickinson
Vice President, Business Development

Iberdrola USA Management Corporation
Durham Hall, 52 Farm View Drive | New Gloucester, ME 04260
(207) 688-6362 | www.iberdrola.com | info@iberdrola.com

IBERDROLA USA

Connect New York
HVDC Project

Contingency Procurement of Generation and Transmission

Inquiry No. Q13-5441LW

Submission to
New York Power Authority

May 20, 2013

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Section 1

Cover Letter

IBERDROLA USA

Len Walker
Manager of Special Projects
New York Power Authority
123 Main Street
White Plains, NY 10601
USA

Re: Contingency Procurement of Generation and Transmission, Inquiry #Q13-5441LW

Dear Mr. Walker,

Iberdrola USA is pleased to submit our proposal for Connect New York HVDC Project, a new 53.3 mile transmission line, as a response to your Request for Proposal entitled "Contingency Procurement of Generation and Transmission, Inquiry #Q13-5441LW."

As you will see from this package, we not only have a solid understanding of the power transmission needs of New York State and Governor Cuomo's Energy Highway and Clean Energy Goals, but we believe that our project will satisfy all five of the major goals to: (1) expand and strengthen the energy highway; (2) accelerate construction and repair; (3) support clean energy; (4) drive technology innovation; and (5) expedite implementation. Through the design and construction of our 1,000 MW HVDC bulk transmission line running predominantly along the New York State Thruway from New Scotland substation to the Hurley substation, our project will:

- Update New York State's energy infrastructure.
- Bring jobs to upstate New York.
- Utilize the latest in energy technology and provide allowances for even newer technology to tap into our transmission line in the future.
- <u>Be online by June 2016</u>.

If you have any questions, please contact me anytime at (207) 688-6362. Thank you for your consideration for this exciting project!

Yours sincerely,

Thorn Dickinson
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Section 2

Executive Summary

Executive Summary

About the Iberdrola team

Iberdrola USA, and its parent, Iberdrola S.A., bring tremendous experience and investment capabilities to New York. Iberdrola is an energy services and delivery company that services more than 2.4 million customers in Upstate New York and New England through its five operating companies: Central Maine Power, Maine Natural Gas, New Hampshire Gas, New York State Electric and Gas (NYSEG), and Rochester Gas and Electric (RG&E). Iberdrola today is one of the five largest global utilities and is the world leader in the wind sector. The company's 33,000 employees manage assets worth $130 billion that in 2011 produced revenues worth $42 billion and a net profit of over $3.5 billion dollars.

Iberdrola has won a number of international awards, such as the nomination as the leading electric utility on the "Global 100 Most Sustainable Corporations in the World."

For this project, Iberdrola USA will be the primary developer for this project. Iberdrola USA will work with Iberdrola Engineering & Construction (a subsidiary of Iberdrola) on the engineering design of the transmission line, The Cianbro Company for assistance with managing the EPC portion of the project, Gilberti Stinziano Heintz and Smith, P.C., for any legal and permitting support services, and Spectra Environmental Group, Inc. for the environmental permitting aspects of this project,

Iberdrola Engineering & Construction (E&C) is one of the world's leading electrical engineering companies, with projects in more than 30 countries across Europe, Asia, Africa and America. Iberdrola E&C provides services ranging from basic studies to "turnkey" projects, in the generation, nuclear, networks, and renewables sectors. In fact, Iberdrola E&C has been able to undertake more than 500 substations in 500 kV, 230 kV, 132 kV and lower tension levels. In the transmission and distribution realm, Iberdrola E&C is an expert in analyzing and integrating new installations, designing new substations, designing cable lines (underground, as with this project, as well as aerial and submarine), as well as protections, control, and measurement tools.

The Cianbro Companies, a 100% employee-owned company, specializes in the construction of transmission, mechanical, and electrical projects. Cianbro is the managing member of the Atlantic Energy Partners, LLC, the developer of the Neptune Regional Electrical Transmission System. The Neptune Transmission System provides up to 600 MW of electric power from the PJM system to the LIPA grid on Long Island via a 500 kV, high voltage direct current cable running from Sayreville, NJ to New Cassel, NY. The converter stations utilize both AC and DC power respectively. Since starting operation in mid-2007, Neptune has provided, on average, nearly 25% of the electric power used on Long Island.

Gilberti Stinziano Heintz and Smith, P.C. is a legal firm specializing in clients in the energy field, including large, multi-plant power producers, natural gas pipeline operators, and electric transmission line developers. They have been counsel on power generation projects that total more than 5,000 MW of generating capacity and have counseled electric transmission companies on projects involving more than 450 miles of transmission line.

Spectra Environmental Group, Inc. is an environmental engineering firm located in Latham, New York and is a self-certified federal Small Business Enterprise (SBE). With 37 employees and 20 years in business, Spectra has experience in the preparation of environmental permit applications and Environmental Impact Statements. Spectra's staff are experts in New York State environmental permitting regulations; in fact, president Robert LaFleur has over 30 years of experience in the environmental consulting field, and president John H. Shafer, PE has over 50 years of experience in the engineering field and is the former Chief Engineer at the New York State Department of Transportation and Executive Director of the New York State Thruway Authority.

Key Project Management Team Members

The project management team has extensive experience in power transmission, including developing transmission lines, managing projects from design through operation, permitting, legal expertise, technical expertise, and construction abilities. Our team is highly familiar with New York State requirements and have been involved in many projects within New York State, such as the NEPTUNE project.

The project management team will include representatives from:

Iberdrola USA

- Project Owner
- Financing
- Project Oversight
- Key managers: Robert Kump; Thorn C. Dickinson; Jose Maria Torres

Iberdrola Engineering & Construction

- Transmission line cost estimates and design
- Converter station design
- Key managers: Eduardo M. Duchini; Gonzalo Echevarrieta Alvarez

The Cianbro Companies

- EPC managing consultant
- Key managers: Peter Vigue; Ernest E. Kilbride

Gilberti Stinziano Heintz and Smith

- Legal representation
- Article VII application process
- Key managers: William J. Gilberti, Jr., Esq.; Brenda D. Colella, Esq.; John F. Klucsik, Esq.

Spectra Environmental Group

- Article VII application process
- Environmental permitting
- Expert testimony
- Key managers: Robert C. LaFleur; Paul Adel, PE; John D. Ciampa

Project Summary

"Connect New York" is a proposed 1,000 MW HVDC bulk transmission line running from New Scotland (Albany County) to Hurley (Ulster County), New York. The transmission line will run from NYISO Zone F to Zone G. This 53.3 mile transmission line will be connected to the main electrical lines at two strategic converter stations (AC/DC converter stations) at either end of the transmission line. The line would utilize existing public utilities adjacent to the New York State Thruway right-of-way, New York State Department of Transportation right-of-way, and small selections of private right-of-way. The entire line is proposed to be located underground, thereby minimizing environmental issues and protecting viewsheds of the Hudson River and Catskill Mountains.

Project Benefits

There are many compelling benefits associated with the Connect New York initiative, but perhaps the most important one is that it is achievable. More specifically, this project is entirely possible to be online by June 2016. Many of the mine fields threatening the approval of customary transmission proposals are avoided with the Connect New York approach. Environmental and NIMBY challenges are largely circumvented by utilizing the existing right-of-way. Eminent domain is similarly not an issue.

Equally important, Connect New York is all about New York. It will foster New York's desire for energy independence by building an energy highway that will change the financial dynamics of closing Indian Point Energy Center and repowering upstate plants while encouraging new investment in on-shore wind development in upstate New York. It will reduce the state's annual energy bill by reducing congestion and allowing lower cost, cleaner energy upstate to flow into New York City and Long Island. This will finally reduce downstate energy bills at a time when consumers need some relief. Connect New York will provide New York State with a state of revenue through lease fees with the New York State Thruway Authority.

The energy most likely to be transmitted on Connect New York (gas and renewables) will displace more expensive and higher greenhouse gas energy produced by the older vintage fossil fuel plants in the metropolitan New York/Long Island regions, thereby reducing greenhouse emissions as well as energy costs.

Furthermore, Connect New York utilizes state-of-the-art energy technology. The project utilizes a DC transmission line, which has a multitude of benefits, including system reliability, fewer losses, fewer environmental impacts, reduced trenching, less material used, and a smaller footprint.

Finally, Connect New York will create thousands of New York jobs, not only during the construction period but subsequently by enhancing prospects for upstate plants to invest in repowering as a new downstate energy market is opened up. The same holds true for renewable development east of Lake Ontario, assuming that long-term power purchase contracts can be put into place to support the 2015 RPS mandate.

In summary, the time has come for this transmission infrastructure proposal to be implemented as the foundation for Governor Cuomo's "Power NY" vision and the "New York Energy Highway."

Project Schedule

This project can—and will—be online by June 2016. Our team proposed to achieve this in three ways:

1. By expediting the permitting process. Our Article VII application is underway and will be submitted to the PSC long before a decision on this proposal, "Contingency Procurement of Generation and Transmission" (Inquiry # Q13-5441LW) has reached a decision.
2. Much of the design for this project has already been completed. We will tweak the plans that we already have in place in order to expedite the schedule for this project.
3. We have broken our project out into two phases in order to ensure that this most critical project path through the most congested portion of New York State is completed by June 2016. This proposal is for Phase 1 (New Scotland to Hurley) of a two-phased project that will ultimately tie the transmission line from Queens to Utica.

Project Cost

Iberdrola USA will form a separate, wholly-owned legal entity whose sole purpose will be to construct, own, and operate the Connect New York project. Iberdrola S.A., Iberdrola USA's parent, and Iberdrola USA will private all equity capital requirements and any credit support necessary during the construction phase.

Total project cost is estimated to be $633 million. This is an estimate of total costs based on traditional cost of service treatment. This number can vary for a number of reasons.

Section 3

Description of the Project

Description of the Project

Overview

The catalyst for this Request for Proposals from the New York Power Authority stems from Governor Andrew Cuomo's "New York Energy Highway" policy document, which outlines the blueprint and long-term strategic goals for upgrading and revitalizing New York State's electric transmission infrastructure.

Key to the discussion of upgrading New York's infrastructure is the creation of several contingency plans to address potential power plant closures, such as the closing of the Indian Point Energy Center outside of New York City. According to the November 30, 2012 New York Public Services Commission (PSC) "Order Instituting Proceeding and Soliciting Indian Point Contingency Plan," New York State is addressing the possible closure of this energy facility by the summer of 2016. Consequently, the PSC and process administration New York Power Authority have issued a formal RFP to seek proposals from qualified generation and transmission project developers that address the reliability needs that would result with the closure of the Indian Point Energy Center in the summer of 2016.

"Connect New York" offers a solution to this contingency plan dilemma. Connect New York is a proposed, 1,000 MW HVDC bulk transmission line running from New Scotland (Albany County) to Hurley, New York (Ulster County). The 53.3 mile transmission line will run from NYISO Zone F to Zone G. Connect New York will be connected to the main electrical lines at two strategic converter stations (AC/DC converter stations) at either end of the transmission line. This underground transmission initiative would utilize existing public right-of-way along the New York State Thruway and small selections of private right-of-way.

This project proposes to use high voltage direct current (HVDC) technology, which has greater efficiency than AC current technology when used in long distances. The advantages of HVDC transmission lines are numerous: they are more stable than AC current; HVDC has fewer losses; HVDC has reduced construction costs due to fewer materials and a smaller footprint; and HVDC has fewer adverse environmental effects than AC current.

The technical requirements and system parameters of this project are as follows:

Power to Transmit	1,000 MW
Transmission voltage level	
▪ Option 1	+/- 320 kV DC XLPE
▪ Option 2	+/- 500 kV DC MI
Type of HVDC Project	Point to Point Transmission
HVDC Technology	Voltage Source Converter (VSC)
HVDC Configuration	Symmetrical Monopole
Type of HVDC Transmission	Underground Cable
Power Flow	Bi-directional
Route Length	Approx. 125 km
Converters	2 VSC HVDC Converter Stations
Number of Circuits	One
Number of Cables	Two power cables (positive and negative), plus two optical fibre cables and DTS
Circuit Arrangements	Cables installed in one thermally independent trench
Spacing of Cables	250 mm
Cable Surround	Stabilized material
Type of Joints	Straight-joints
Type of Terminations	Outdoor terminations
Sheath Bonding and Earthing	Cable sheaths earthed along the route and at both converter stations

There are two potential technologies available in utilizing HVDC: LCC-HVDC (Line Commutated Converter HVDC) technology and VSC-HVDC (Voltage Sourced Converter HVDC) technology. The Iberdrola team recommends the use of VSC-HVDC technology for the Connect New York project because it provides functional advantages over LCC-HVDC technology and conventional HVAC solutions.

Although there are a few types of VSC-HVDC technical solutions, all of them are based on the fast switching capacity of IGBTs (up to 2 kHz). Turn On and Turn Off impulses are sent to the different IGBT modules, which are connected in a series in order tor each the operating voltage level, to conduct or not the AC voltage received from the converter reactor. The VSC transistors' voltage output can be controlled in phase angle and amplitude, allowing an independent active and reactive power control. Benefits of VSC-HVDC technology includes: (1) independent control of P & Q at the same time; (2) capability of operating connected to weak AC networks and even to passive AC networks; (3) black start capability; (4) fast power reversal; (5) no need for specific and more expensive power converter transformers; (6) minimum filtering required; (7) possibility of modular design; (8) minimum layout/footprint; and (9) ability to work with both types of HVDC cables: extruded and mass impregnated. Figure 1 and 2 illustrate VSC-HVDC converter stations.

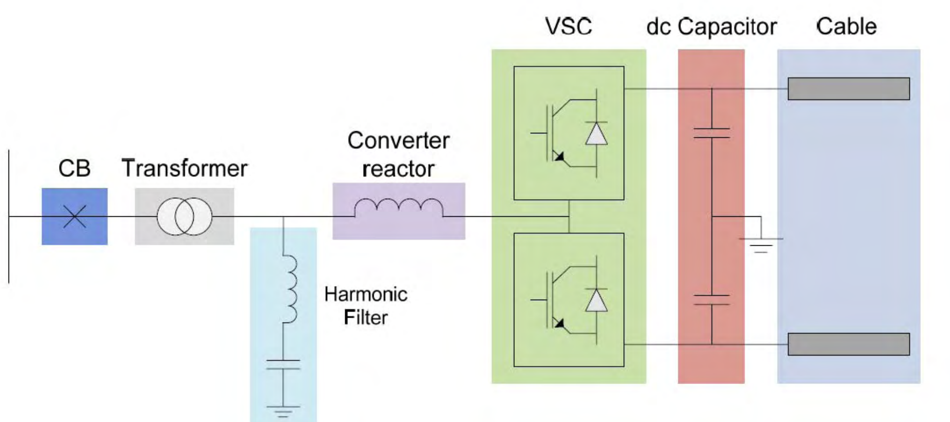


Figure 1: Power elements in a VSC-HVDC Converter station

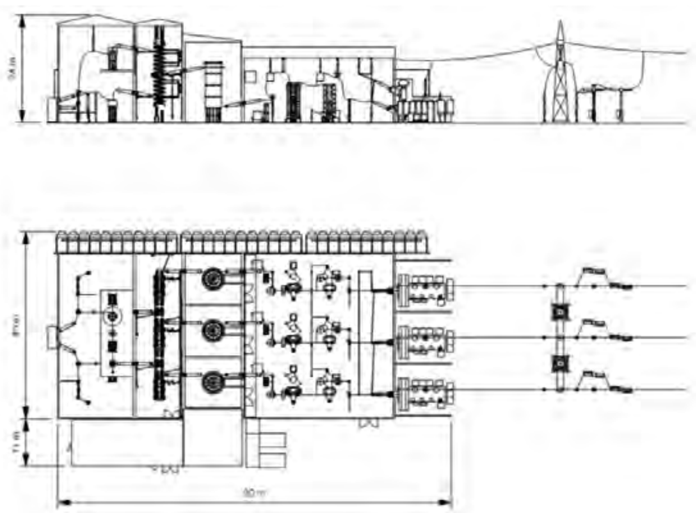


Figure 2: Example of a VSC-HVDC Converter Station Layout

This proposal considers two possible alternatives regarding the transmission voltage level.
The fundamental reason for this is the direct influence of the transmission voltage on the budget of the project, as well as on the losses of the transmission link.

The increase of the transmission voltage impacts the budget by means of increasing the costs of the equipment required for the transmission link. In general, equipment for higher voltages require higher grade equipment and this is more expensive in terms of cost.

Regarding the losses of the transmission link, higher voltages mean reduction of the current for the same power transfer. As ohmic losses constitute one of the main contributors to the overall transmission link losses, at higher voltages the losses of the transmission link are minimised.

Thus, the final solution shall reach the best compromise of costs and losses. To ease the decision of the final solution to be adopted, two possible scenarios have been proposed regarding to the voltage level of the transmission link:

- ± 320 kV
- ± 500 kV

For this project, Iberdrola USA has contacted several HVDC converter and cable suppliers for general cost estimates and detailed technology information. Iberdrola received interest and detailed information from ABB and ALSTROM for converter technology and from NEXANS and GENERAL CABLE companies for cable technology. General information about ABB, ALSTROM are included at the end of this section for your consideration.

Connect New York will be buried in the New York State Thruway right-of-way for the vast majority of the project length. By doing this, New York State will earn income from the lease agreement. Furthermore, environmental and NIMBY challenges will be largely circumvented by utilizing an existing right-of-way. Eminent domain issues will be lessened.

Connect New York will be located entirely underground. This will ensure that viewsheds of the Hudson River and the Catskill Mountains are unimpeded. Underground cables take up less right-of-way than overhead lines and are also less affected by bad weather.

Ultimately, Connect New York will expand and strengthen the energy highway by alleviating a tired and congested transmission infrastructure currently in place, especially in the transmission corridor consisting of: Central East-New Scotland-Leeds-Pleasant Valley, which is identified in the New York Energy Highway Blueprint as an area of most concern.

Alternative Routes

The Iberdrola USA team evaluated six routes for this project:

1. Starting at Marcy substation near Utica, NY
2. Starting at the New Scotland substation near Albany, NY
3. Creating a new substation on the Thruway right-of-way, near Coeymans where the existing 345Kv transmission line crosses the Thruway
4. Ending at the Rainey substation in Queens, NY
5. Ending at the Ohioville substation in Ulster County
6. Ending at the Hurley Avenue substation in Ulster County

Ultimately, the Iberdrola USA team chose a route starting from the New Scotland substation near Albany to the Hurley Avenue substation for a number of reasons. First of all, the more compact route ensures that the June 2016 online date is attainable. Secondly, this route travels along the Thruway right of way for the majority of the length, and uses public right-of-way for the short sections from the Thruway to the substations. These public right of ways include property sections that are owned by National Grid and the Central Hudson Gas and Electric. Thirdly, by utilizing existing substations that have large adjacent vacant land we can ensure that any required expansion of the AC substation and the construction of the two converter stations can be done efficiently.

As noted in this RFP submittal, all of the required prerequisites are met with a route from New Scotland to Hurley. However, as detailed in our RFI submittal last year, we believe a HVDC project with a larger scope better addresses the principles laid out in the New York Energy Highway. As a result, Iberdrola USA will continue to develop the larger project; however, this larger project is outside of the scope requested by this project. Consequently, all further discussion focuses on the New Scotland-Hurley Avenue route.

Additional Information

Additional information about Iberdrola's choice in using HVDC technology can be found in Appendix B: Additional Information.

Technical Information

In order to provide the power transfer requirement and compliance with the technical request for information in accordance with the scope detailed above, Iberdrola USA is proposing to install two HVDC Converters, based on the VSC (Voltage Source Converter) Technology.

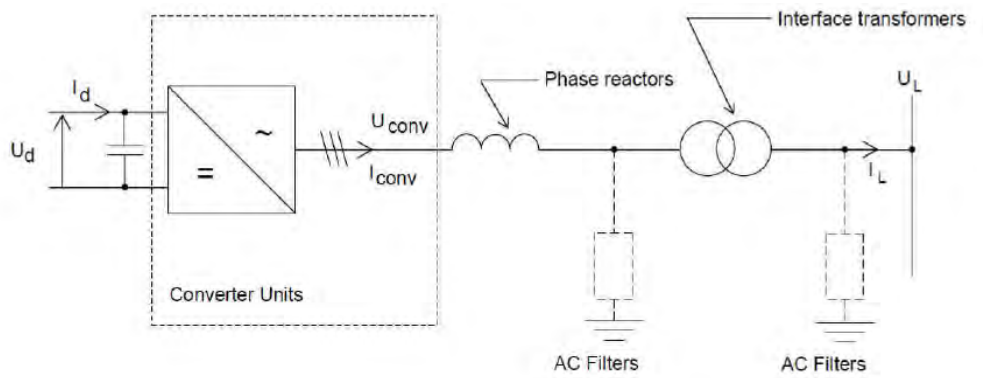


Figure 3 – Typical VSC System

1.1 Technical Proposal: VSC System Description

This type of converter uses self-commutated semiconductors with IGBT valves. These devices are controlled for turn-on and turn-off, that is, they are devices that can switch on and off independently of the current through it. The scheme proposed utilizes half-bridge IGBT sub-modules connected in a symmetrical monopole configuration. The maximum DC voltage of the scheme is selected according to the requirements stated at ±320 kV and ±500 kV and the rated nominal current is selected accordingly to meet the 1000 MW delivered at the point of common coupling on the AC busbar at the receiving end converter, under all normal operating conditions.

The main components of the VSC HVDC converter station are described fully within Section 1.2.

According to its principle of operation, only a few components are essential in a VSC HVDC scheme. These are:

- A means to convert DC into AC voltages provided by a converter comprising VSC valves and controls
- An AC side reactance provided by phase reactors, transformers and a combination of filters if they are needed
- A DC voltage source provided by at least one VSC DC capacitor

1.1.1 Advantages of VSC Technology

As described, VSC technology has many advantages inherent to the design of the converter:

- Both active and reactive power levels can be achieved without the need for separate compensation equipment.
- Little or no filtering requirements and no reactive power switching, significantly reduces the engineering and land area requirements.
- For the required HVDC link configuration as a symmetrical monopole, it is possible to use normal or ordinary AC power transformers.
- Operation down to very low short circuit ratios therefore the converter can connect to AC networks without the need for complex studies of system reinforcement.
- Fast power reversal by reversing the direction of the current therefore enables the use of lower cost polymeric cabling and allows continuously variable power from full power in one direction to full power in reverse direction.
- Inherent black-start capability.
- VSCs can operate at zero power requirements, something LCC converters cannot.
- Multi-terminal configurations are simpler to engineer than classic LCC configuration.
- No commutation failures, which can occur with LCC converters.

1.2 VSC Components

1.2.1 AC Switchyard

The AC Switchgear includes the AC soft start resistor, surge arrester, voltage and transformers. In general, AC switchgear are located outdoors, unless special requirements apply.

1.2.2 Converter Transformers

The converter transformers connect the AC switchyard to the valve hall, transforming the voltage from the AC voltage to the required voltage for the performance of the valves. The windings connected to the AC switchyard are referred as line windings, and the windings connected to the valve hall are normally referred as the valve windings.

The main functions of the converter transformers are:

- To supply the converter bridge with a desired AC voltage, adjusting the amplitude by means of the On Load Tap Changers (hereafter called OLTC).
- To provide galvanic insulation between the converter bridges and the AC switchyard.
- To limit the short-circuit current into the valve in case of a fault inside the converter bridge
- To act as a barrier for the DC voltage, preventing it from entering into the AC system.

For the proposed HVDC link configuration as a symmetrical monopole, it is possible to use normal or ordinary AC power transformers, as those installed in AC substations.

1.2.3 Characteristics and arrangements

The power transformers in a VSC HVDC scheme are not exposed to DC voltage stresses or harmonic loading, allowing the use of ordinary transformers, as installed in AC substations, the same design methodology.

In most of the cases, VSC schemes do not require tap changers, but with an on-load tap changer (OLTC), the transformer ratio can be continuously optimized to maximize the steady-state power capability of the converter, compensating the internal voltage drops of the HVDC converters and the deviations of the AC busbar voltage from the nominal value. An additional benefit of an OLTC is that it can minimize the power losses of the VSC transmission system.

Various arrangements for the transformers can be employed in an HVDC converter station depending on the transformer configurations. Transformer banks can be installed as a single 3-phase unit or as 3 single-phase units.

In general, power transformers are located outdoors between the AC substation and the valve hall buildings.

During the detailed design phase it may be necessary to add an auxiliary winding connected in star to provide an additional auxiliary power supply. By utilizing the well-established 3rd harmonic injection technique on the converter side of the converter transformer it is possible to maximize the amount of current flow during any conduction period whilst minimizing the converter valve switching instances. The delta winding of the converter transformer will trap the line-to-ground voltage distortion to the converter side of the transformer.

> From supplier consultation:
>
> Regarding converter transformers, ALSTOM proposes conventional AC substation design transformers, arranged as single phase 2-winding units, each having a grounded star line winding for connection to the AC network, together with valve winding connected in delta to feed the IGBTs. Additionally, incorporates an OLTC on the transformer to allow for an extended range of AC operating voltages on both ends of the HVDC link.

1.2.4 IGBT Valves

The Insulated Gate Bipolar Transistor (IGBT) is a device with high input impedance and large bipolar current-carrying capability. The equivalent circuit is represented in next figure:

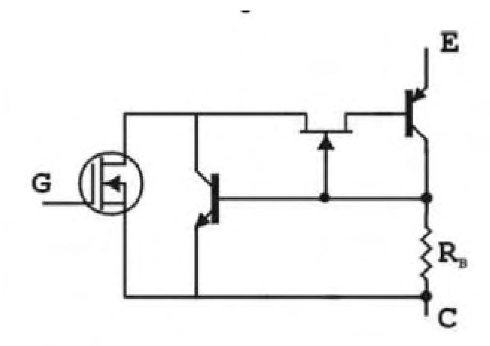


Figure 4 - IGBT Equivalent circuit

Where G is the gate, E the emitter and C the collector.

The IGBT has three basic modes of operation:

- Reverse blocking: The IGBT is reverse biased when the collector voltage is lower than the emitter voltage.
- Forward blocking: With positive voltage between the collector and the emitter and without the gate signal, the IGBT is blocked.
- Forward conduction: When forward biased, the IGBT can be switched by a positive voltage between gate and emitter. In this condition there is the on-state forward voltage.

A complete IGBT position consists of an IGBT, an anti-parallel diode, a gate unit, a voltage divider and a water-cooled heat sink. Each gate includes gate-driving circuits, surveillance circuits and optical interface. The gate-driving electronics control the gate voltage and current at turn-on and turn-off to achieve optimal turn-on and turn-off processes of the IGBTs.

1.2.4.1 Modular Design

The preferred VSC technology at present is the so called Modular Multilevel Converter (MMC).

In order to reduce the harmonic content of the AC output waveform, phase voltages can assume 2n+1 levels between +Vdc and -Vdc. 2n DC supplies, provided by 2n DC storage capacitors, are connected in series, providing 2n+1 discrete voltage levels.

The voltage between the terminals of each half-phase varies between 0 and +Vdc, and the voltage of each phase of the bridge converter consists of a high number of discrete voltage steps. The converter bridge works as a controllable voltage source (possible regulation of amplitude and phase), supplying a voltage waveform close to a sine wave. The waveform of a multilevel VSC converter is represented in the next figure:

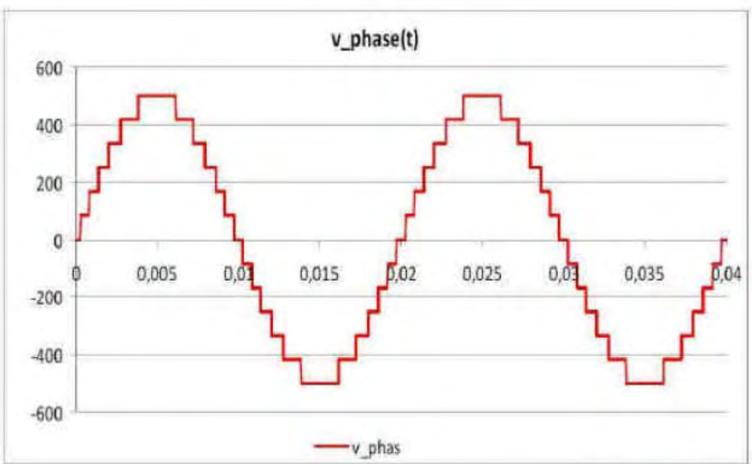


Figure 5 - Multilevel Waveform

A general Modular Multilevel Converter system module arrangement single line diagram is shown in Figure 6.

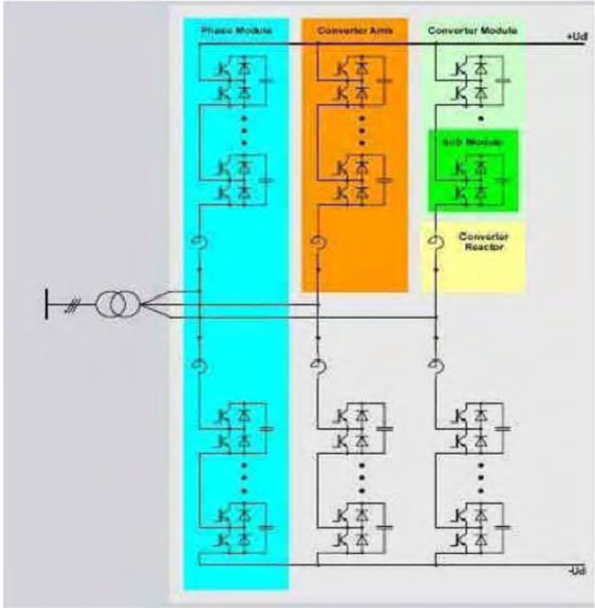


Figure 6 - MMC SLD Modular Arrangement

<u>From supplier consultation:</u>

Figure 7 and Figure 8 show the Alstom HVDC MaxSine® Sub-module and module, that includes the IGBT position and the capacitor units.

Figure 7 - HVDC MaxSine® Sub-module

Figure 8 - HVDC MaxSine® Module

The valves proposed by ALSTOM are the latest generation of IGBT device in the form of a Modular Multi-level Converter (MMC), as shown in Figure 9. The IGBT Valves consist of a number of series-connected sub-modules, arranged in modules of 8, and stacked inside the valve hall.

The total amount will include the necessary quantity of redundant sub-modules to allow for failure of individual components while meeting the required availability performance. In the half-bridge configuration proposed there are two IGBT devices in each of the sub-modules.

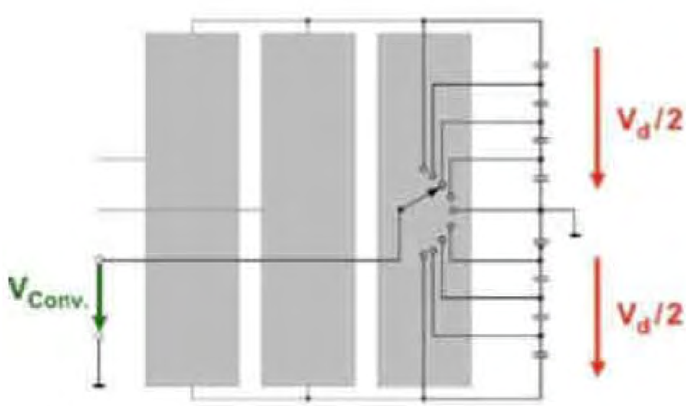


Figure 9 - Modular Multilevel Converter

Proposed technical solution by ABB for the project is the VSC-based HVDC transmission system called HVDC Light, which is also based on Modular Multilevel Converter technology. In particular, ABB's HVDC Light VSC Generation 4 has the half-bridge layout.

1.2.5 The Converter Reactors

The converter reactors are reactors connected in series with the IGBT valve, on the AC side between the power transformers and the converter terminals. They allow the possibility to deliver reactive power together with the active power.

1.2.6 Smoothing Reactor

There is the possibility of requiring DC smoothing reactors and DC filters; however, for this project, it is assumed that as the DC circuit is entirely underground, probably it will not be needed.

In case it is needed, the main functions of the reactor are:

- to keep the DC current as smooth as possible in all the range of power transmitted (especially at the technical minimum)
- to limit the overcurrent in the converter due to faults along the DC line/cable or to commutation failure
- to reduce the risk of resonances in the DC circuit for the characteristic and noncharacteristic harmonic voltages
- to reduce, together with the DC filter (if any), the harmonic currents into the DC link

It has been discussed with different suppliers the necessity of incorporating DC smoothing reactors and DC filters. However, for this proposal it is assumed that as the DC circuit is entirely underground, these can be excluded.

1.2.7 Cooling Equipment

During the switching operation of the IGBTs an amount of heat is generated. In order for that heat to be dissipated away from the components to prevent damage from overheating, a closed loop cooling water circuit will be installed.

1.2.8 Control Building

The control building is an area out of the valve hall that controls the operation of the HVDC converters. It also provides a suitable environment for the protection system components required for the protection of the various elements of the converter station. Within the control building the operator is able to monitor and control the output of the various elements that make up the complete converter station. This also provides the interface point between this converter and other associated converters on the same HVDC link and with Remote Control Centers to remotely operate the HVDC Link.

1.2.9 Control System

In a typical two-terminal DC link connecting two AC systems, the primary functions of the DC controls are to:

- Control power flow between the terminals
- Protect the equipment against the current/voltage stresses caused by faults
- Stabilize the attached AC systems against any operational mode of the DC link

The two DC converter stations have their own local controllers, which are the point of control when operating in Station Control Mode. When operating in System Control Mode, a centralized dispatch centre can communicate a power order to one of the converter stations which will act as a Master Controller and has the responsibility to coordinate the control functions of the DC link with the converter station on the other end.

One major benefit of HVDC is that the power transfer through the link is absolutely controlled according to the different control modes, and therefore the power through the lines to and from upstate NY and downstate NY may be held at whatever value is required, up to but never exceeding the thermal limit.

Different control modes are possible in HVDC installations, including:

- Constant Power Control – The operator sets a power reference and a ramp rate or a time window to reach that power reference at the end of it, and the control system adjusts the power flow accordingly.
- Constant Frequency Control – The operator sets a Frequency Reference and a frequency slope, and the control system will adjust the power flow through the link to remain on the slope line, sharing the duty with the generators in the network in maintaining a constant frequency once reached the desired reference.
- Power Modulation, or Swing Damping are detection mechanisms that may be incorporated into the HVDC system design such that when the control system detects a power swing in the network caused by such events as a line or generator trip, an automated response may be activated which modulates the power through the link to damp out the oscillation.
- Sub-Synchronous Damping Control – This is similar to power modulation, but focused more on the detection of sub-synchronous oscillations between generators, or between the HVDC link itself and the generators.

In addition, VSC technology has the advantage of giving the possibility to control two energy parameters at the same time, and as a consequence can combine different control modes depending on the type of the AC network where it is connected.

There are three types of AC networks depending on the stiffness of the AC voltage at the point of common coupling (PCC) with the VSC-HVDC converter: stiff (strong), weak, and passive.

Therefore, different control strategies are possible depending on the connected AC grid. For instance, control of system AC voltage by the VSC converter for connections to passive or weak AC grids, with possibility of additional Active Power Control or DC

Voltage Control. When connected to stiff AC networks, P and Q or Q and Udc Independent controls are possible.

The various control modes may be prioritized in such a way that changes in AC network conditions may override the present control mode settings and power transfer level of the HVDC link. For example, if the link is in constant power control mode, and the AC system frequency on the sending end of the link falls and reaches a pre-set limit, then the frequency control mode may be automatically activated to follow the slope characteristic and to reduce the level of power being extracted from that system through the link. Other scenarios are possible and should be defined as part of the specification to ensure that these functions are properly installed in the software and verified during factory tests.

As long as system operation or the Dispatch Center is the selected control location in System Control Mode, then its personnel has full control of the HVDC link. The selection of control location is normally a request/release function between "control desks".

Changing between control modes is normally "bumpless," as far as functionally possible. For example, if leaving Frequency Control to enter Power Control, the control system will normally introduce the present power transfer level as the Power Reference set point. Similarly and vice-versa, if the operator selects Frequency Control, the control system will introduce the present system frequency as the Frequency Reference set point. The operator is then free to adjust new references as required.

Shutdown is not normally required to change between control modes.

The HVDC control system can use established and common industry-standard communication protocols such as DNP-3 implemented on a comprehensive fully integrated network, with all intelligent equipment/subsystems connected. In this way all status, alarm, measured values, commands, configuration, etc information may be easily communicated throughout the network as necessary. More recently introduced protocols such as per Standard IEC61850 may also be used, which is fast becoming the de-facto standard for substation equipment and systems such as this. External communications between the HVDC stations and the HVDC owner facilities, and with other controlling and monitoring entities such NYPA, NYISO, ConEd and others in the wider telecommunications/internet media may also be provided according to requirements, with appropriate security encoding and access control.

1.2.10 DC switchyard

Within the DC switchyard there are a number of components which are more-or-less the same regardless of the type of converter configuration chosen. The HVDC equipments are located between the converter valves and the outgoing DC circuits.

The main difference is that in an HVDC VSC converter station the smoothing reactors are considerably smaller than one used in an LCC HVDC converter station; however, the design methodology is quite similar to that for LCC HVDC schemes. The harmonics to be filtered in a

VSC scheme oscillate at higher frequencies than in LCC case, and may not be required to be filtered, but if required they are lower rated.

A VSC HVDC switchgear contains many of the same elements in an LCC HVDC converter station:

- Measurement transducers
- Disconnectors
- Surge arresters
- Smoothing reactor
- Insulators

The technical characteristics and principle functioning of HSC HVDC switchgear scheme remain the same as in an LCC HVDC scheme.

1.3 Operation

Normally the HVDC link converter station control rooms include a full redundant control operation facility, with redundant HMI. This is required during the commissioning phase and may prove useful during any future start-up following a major outage or in the event of system upgrades. The HVDC controls can be integrated into the owners' network control system, allowing the station to be operated remotely, and this is typically from the grid control or dispatch center. This will allow the operators and remote engineering support staff to have full access to the functionality of the HVDC stations and full diagnostic information from the monitoring points at the station.

The decision of how many staff to provide at each converter station is dependent on the requirements of the owner. It is possible to customize the HVDC link to provide the full spectrum of staffing vs. automation according to the preference of the owner, ranging from fully manned 24/7, with operation and maintenance staff present at all times at one extreme, and at the other extreme, totally unmanned under remote control at all times.

In most HVDC systems very few routine regular maintenance activities are required, the most common being the various systems/subsystems with moving parts, such as the valve cooling plant (checking filters and make-up tank levels for proper function/levels, etc), the converter transformer tap changers, and the AC harmonic filter circuit breakers. Generally the approach to the design is that all aspects of the plant are provided with sufficient monitoring and alarm functions that any failure is mitigated by a backup or redundant system. The failure is notified to the operation and maintenance personnel so that either the repair can be carried out while the station is in operation or an outage can be scheduled when convenient to carry out the repair.

> From supplier consultation:
>
> Operation and Maintenance is a service actually offered by different suppliers as a follow-up to the construction contract. As described above, there is a wide range of possible operating strategies, but as an indicative guide it is anticipated that the range of annual costs associated with the

different support services of Operation & Maintenance will be in the range of 0.3% - 1.5% (from minimal call-out support on specific items of equipment only, up to the maximum of full O&M support service) of overall converters contract price. However more information is needed to establish a more detailed scope of supply.

1.4 Maintenance

For the proposed solution, regular maintenance is required to keep the equipment in optimum condition and prevent early life failures. In general, maintenance tasks can be divided as regular routine inspections and major maintenance tasks.

On-line regular and routine inspection, checking and monitoring of the station equipment which does not require a shutdown of the HVDC system but may require the switch off of one of the redundant systems is required.

These inspections are performed on a monthly or a six months basis. The initial frequency of the inspections can be adapted once a base line and readings are established. If the inspection would require the shutdown of a redundant component it is recommended that this type of inspection should be performed during a light load period.

In general, recommended activities are visual inspections approximately once a month and checking of the filters on the cooling plant, as wells as looking for anything out of the ordinary. Remote monitoring can take care of the day-to-day operation aspects.

For a single pole installation of 1000MW, maintenance on main power circuit equipment requires is a complete outage of the station; hence, major maintenance tasks are those which require the HVDC system to be taken out of operation. These maintenance tasks should be performed every two or three years and concentrated on a period of up to 3 days.

The most complex parts of the VSC facility are the IGBT converters and the HVDC control systems; however, the most demanding in terms of maintenance activity are any equipment with moving parts, namely the cooling plant, the switchgear and the transformer OLTC, if one is installed. The Converter equipment and the control systems have extensive monitoring and recording facilities incorporated, presenting the operation and maintenance personnel with real-time and historical indications of the equipment status, including any faults which exist. Sufficient redundancy is normally incorporated in all critical areas of the facility to ensure that a single failure will not cause a total loss of power transfer capability.

Scheduled maintenance is normally carried out on a 2-3 year interval, and it is anticipated that this can be carried out by a 10 man crew in a total of 80 hours, comprising 10 shifts of 8 hours.

For unscheduled maintenance and repair activities, most equipment failures can be replaced or repaired during a short (several hours duration) outage. If a major item of power equipment fails, such as an air-cored reactor or wall bushing, the outage could last approximately one day, as a crane will be required for the heavy lift operation. The most extended outage would occur if a transformer failed. Depending on the access system used, e.g. rail system or skid system, it could take between 2 – 4 days to replace the transformer.

1.5 Redundancy

The converter station will include redundancy in all key systems to ensure reliable operation of the station over its design lifetime, this includes:

- Redundant power electronic sub-modules, typically 2 – 3% above the minimum requirement
- 100% duplication of the digital control system, both at pole level and station level.
- Duplication of digital protection systems, within each of the duplicated control systems

- 100% redundancy in water pumps
- Redundancy in cooling fans
- Duplication of auxiliary power systems

Additional duplication or redundancy would not be necessary in order to meet the normally specified availability requirements.

VSC HVDC stations are still relatively few in number; therefore there are few reports on reliability and availability statistics, as there are for LCC converters. However, we anticipate that, similar to LCC stations, cooling systems and auxiliary power systems will be significant sources of unreliability, hence these systems would have built-in redundancy. The control system can also be a source of unreliability, hence the 100% duplication in the control system. Normally the impact, in terms of outage time, of such failure is low as the station either carries on operation with no loss of power or can be re-started quickly.

1.6 Spares

All electrical power systems are susceptible to failure (unreliability); however, to reduce the risk of power failure, some redundancy is built into the transmission system, making continuity of supply tolerant to single or sometimes double failures.

With this system redundancy, equipment failure will be unlikely to impact availability of supply so long as the equipment can be quickly reinstated, repaired or replaced. For the maintenance and repair these devices, some stock for spare parts will be needed. The determination of how many spare parts are required should be based on a calculation of the required total system reliability and availability and the expected statistical failure rates. It is not necessarily a question of "as reliable as possible," but a consideration of the objective of the link, its reliability with reference to the other elements in the power system, and its likely performance.

Spare parts philosophy directly affects the cost of a HVDC system. This philosophy is unique for each link. The distance between the stations and transport determine whether or not spare parts are separate or common to both stations.

In general, it is prudent to hold spares for all key components, and a recommended spares list would be a normal part of our detailed tender study. This will include major power equipment, such as reactors, wall bushings, switchgear, etc. The transformer is a relatively high cost item, and although transformer failure is a rare event, a transformer failure has a high impact on the station availability if no spare is available; therefore it is normally recommended the purchase of a spare transformer.

The spares strategy would be analyzed and discussed with the different HVDC converter suppliers during the detailed design stage.

1.7 Reliability & Availability

Reliability is identified with the security of the system and the avoidance of power outage. Reliability of an item of equipment or a system may be considered to be its capacity to continue to operate throughout the period that it is called to do so. In contrast to this, availability of an item of equipment or a system is the total time under consideration (for example 8760 hours per year) minus the time required for maintenance (scheduled) and repair (unscheduled). Availability is thus highly dependent on the combination of failure rate and repair time.

> From supplier consultation:
>
> For ALSTOM's single monopole solution, HVDC system is capable of achieving 98.5 % availability, and this is the most common monopole HVDC specification requirement. It may be possible to design a system to meet a higher availability (possibly up to 99%) through additional redundancy in critical sub-systems at additional cost. For reliability, ALSTOM considers 5 station trips on average.

1.8 Losses

Losses constitute a significant component of the life time costs of transmission circuits. For a HVDC installation link, losses occur both in the converter stations and in the cables. Losses in the overall link are typically less for the HVDC scheme than for an HVAC scheme, firstly because there is no skin and proximity effect for the DC current flow, no screen losses, and dielectric losses are far less compared to AC conductors. Secondly, losses are less for the HVDC scheme because there is no reactive power flow in the DC circuit. Because reactive power flow in HVAC connections increases with circuit length, the difference in the power loss between HVAC and HVDC also increases with the length of the circuit. The total conductor losses for DC cables are due to the Joule losses (heat energy will be generated in proportion to the resistance of the conductor and the square of the magnitude of the current).

Converter station losses are normally around 1% for each converter station. Regarding the HVDC cable, normally cable manufacturers set a design target in the range of 1.5% - 2% of rated transmission power for the operating losses in the cables.

In general, converter station losses are quantified by means of no-load losses and load losses.

The no-load losses are those that arise when the HVDC transmission is energized without any power being transmitted and when no reactive power is exchanged between the HVDC stations and the AC system. No-load losses primarily arise in interface transformers, phase reactors and filters as iron or dielectric losses. In addition, various auxiliary systems, such as cooling, heating, and power supply to the control system, also contribute to these losses when the HVDC stations are energized.

The load losses occur when power is being transmitted and the HVDC stations are exchanging power with their AC systems. Load losses increase with the loading of the DC transmission line and the HVDC stations. The load losses arise from ohmic conduction losses in the DC lines and in the HVDC stations. Load losses in the HVDC station come from ohmic conduction losses and from switching losses in the valves equipment.

From supplier consultation:

The operating losses of ALSTOM VSC solution, based on the proposed multi-level converter topology are expected to be in the range 1.0% - 1.1%. It is not possible to give a precise value until more detailed design and rating studies have been carried out. The following table 2 gives a typical breakdown of the anticipated losses, expressed as a % of rated scheme power. These figures relate to each converter station.

Equipment	No load loss (%)	Full load loss (%)	Total loss (%)
Transformer	0.1	0.32	0.42
Power electronic valves	0.04	0.53	0.57
AC reactors	-	0.03	0.03
DC reactors and capacitors	-	0.02	0.02
Auxiliary power	0.02	0.04	0.06
Totals	0.16	0.94	1.1

Table 1 – Anticipated Converter Losses - ALSTOM

ABB for their VSC solution estimates each converter's losses to be as low as 0.9%.

1.9 System Studies

System studies would be performed during the contract phase. These would consist of a number of steady state, dynamic and transient studies to quantify the performance of the HVDC system. These studies would also be required to clarify the design and the rating of the equipment and also to assess the interaction of the HVDC system with other nearby generating sources and the stability of the AC network.

1.10 Converter Station Layout

As described in previous sections, the layout of a VSC station is considerably smaller than a traditional HVDC converter station of the same rating. This is in principal due to reduced requirement of both the reactive power and harmonic filter banks, comparing to the traditional HVDC technology.

It is estimated that for a VSC converter station the land (building footprint) required is in the range of 30 to 40% less than for a traditional HVDC converter station.

Figures 10 and 11 depict typical existing VSC converter station layouts. In further development of the project an in-depth study of the layout is performed and the final footprint designed.

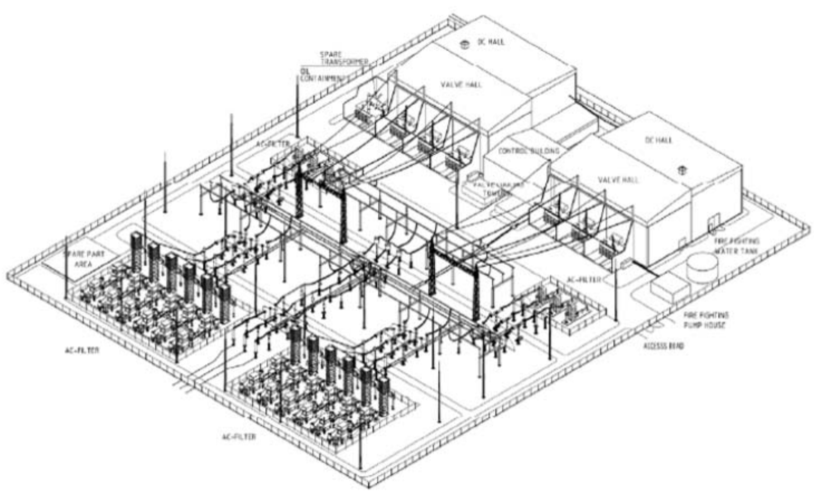


Figure 10 – Typical VSC Station Layout 3D

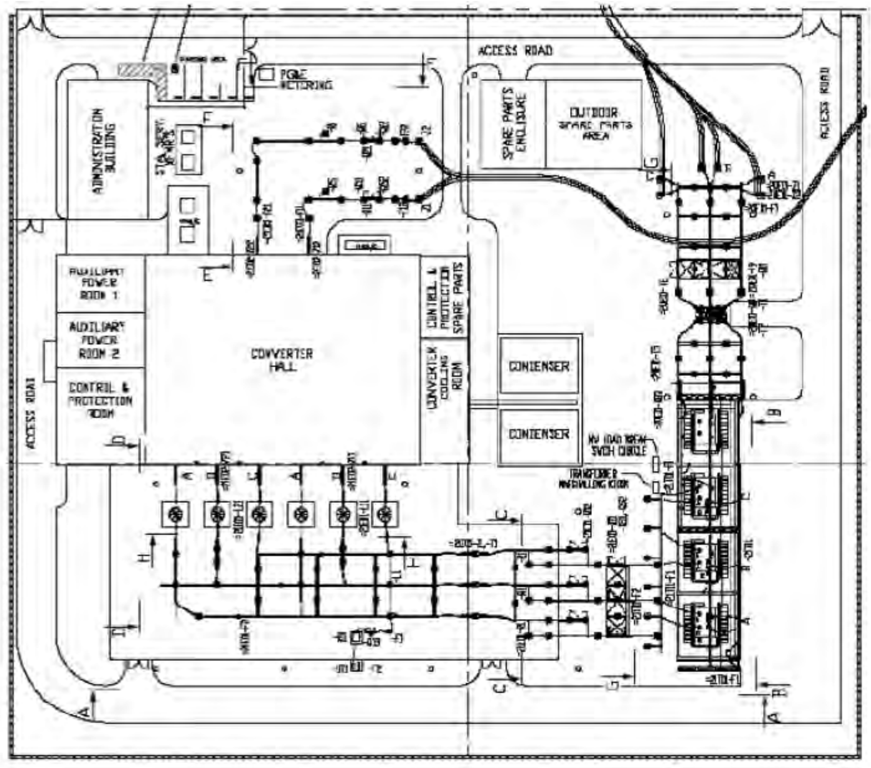


Figure 11 – Typical VSC Station Layout

<u>From supplier consultation:</u>

Regarding ALSTOM's experience in layout design, the layout drawings shown in the following figures illustrate the typical ALSTOM layout specifically for the DC converter part of an overall VSC converter station footprint, which is approximately 820.21 feet x 328.084 feet.

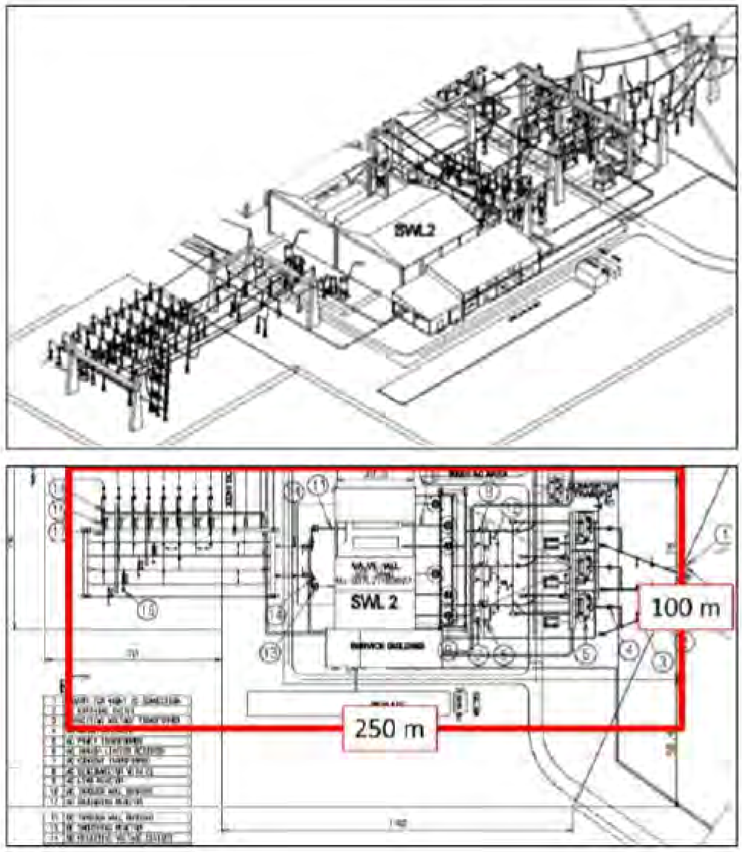


Figure 12 – VSC Layouts - ALSTOM

The AC voltage in the case illustrated was 400 kV, the DC voltage was 300 kV, and the converter rating was approximately 750 MW.

Therefore, considering the differences for the Connect New York project, as: lower AC voltage, slightly higher DC voltage, higher MW rating, the net impact on the overall converter footprint will not be significant, and will mainly be seen as a small increase (about 5%) in the size of the building.

Note that the DC area in the illustration is actually shown here larger than would be anticipated for the Connect New York project, as this was originally drawn with a dual line + dual converter switchyard.

Also the illustration shows an outdoor DC switchyard suitable for connection to an overhead DC line. However in the case of the Connect New York project, it is anticipated that the DC circuit will be mainly underground DC cable. Therefore it is likely that the DC switchyard will consist of a very small number of components, and will occupy a much smaller area than that shown, so it may be possible to achieve a converter station footprint of approximately 656.168 feet x 328.084 feet. ABB's layout designs for VSC converters stations are shown in the next drawings. In this case, this design corresponds to common layout design for ABB's VSC symmetrical monopole solution at ±320 kV.

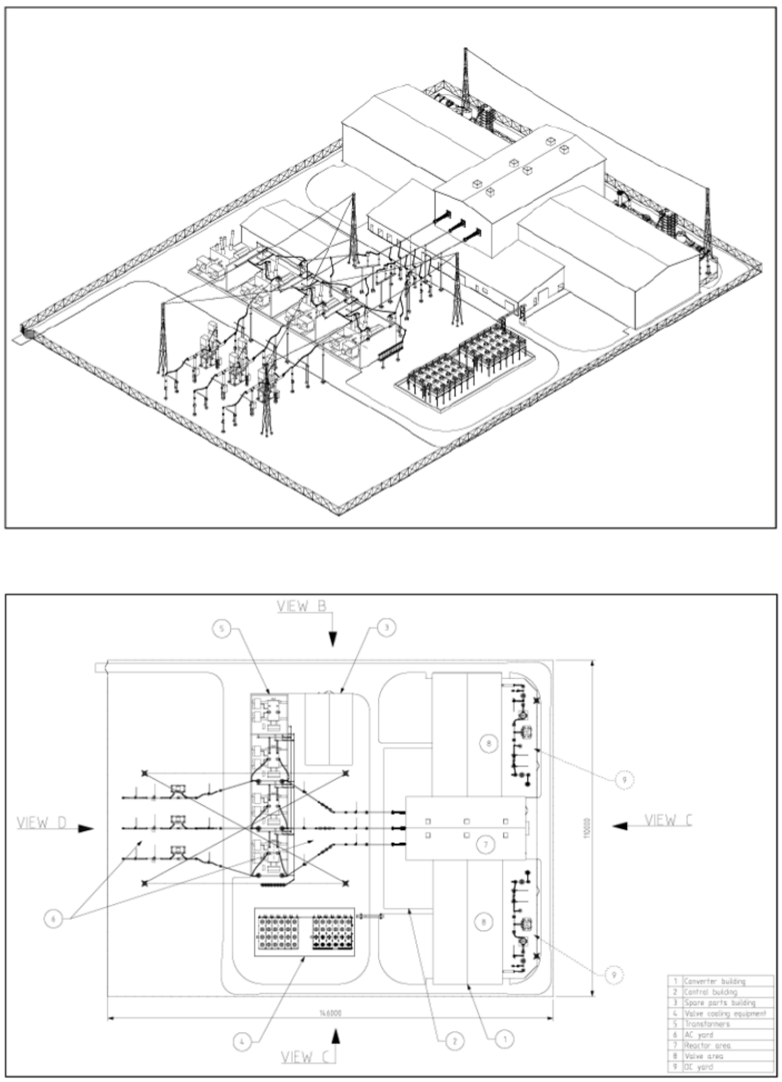


Figure 13 - VSC Layouts - ABB

This converter station footprint will fit within the land available at the Hurley and New Scotland substations.

2. TECHNICAL PROPOSAL – CABLE SYSTEM

The term "cable system" is understood as cable plus relevant accessories.

2.1 Proposed Cable Systems

For the HVDC link under study, three cable system options were analyzed:

- 320 kV DC XLPE insulated cable with 2500 mm^2 copper conductor
- 500 kV DC mass impregnated MI insulated cable with 1600 mm^2copper conductor
- 500 kV DC XLPE insulated cable with 1000 mm^2copper conductor

Ultimately, the 320 kV option was selected due to cost, availability, and optimal transmission.

2.2 Cable System Technical Details

In further development of the project an in-depth study of the parameters required for the design of the cable will be carried out. At this stage the following parameters have been used for the conceptual design of the proposed cable.

Ambient Temperature

	Ambient Temperature (Environment Cables) [ºC]	
Cables Installation	Winter (W)	Summer (S)
Ducted Trench	10	25

Table 2 - Ambient Temperature

Cable Environment Thermal Resistivity

Backfill Material	Cable Environment Thermal Resistivity (K·m/W)	
	Winter (W)	Summer (S)
Inside 50°C Isotherm		
Selected Sand	1.2	2.7
Stabilised Backfill (CBS)	1.05	1.2
Unspecified	1.05	3
Outside 50°C Isotherm		
All Materials	1.05 (Selected Sand 1.2)	1.2

Table 3 – Cable Environment Thermal Resistivity

Cable Depth along the Route

Possible route sections have been studied for the Connect NY project in order to cover most foreseeable situations in this type of connection. These routes are mapped in Section 9: Proposed Resource Development Plans and Schedule.

There are three ways to route the cable underground to the two converter stations:

- Standard trench configuration
- Highways and railways crossing configuration
- HDD for special crossings

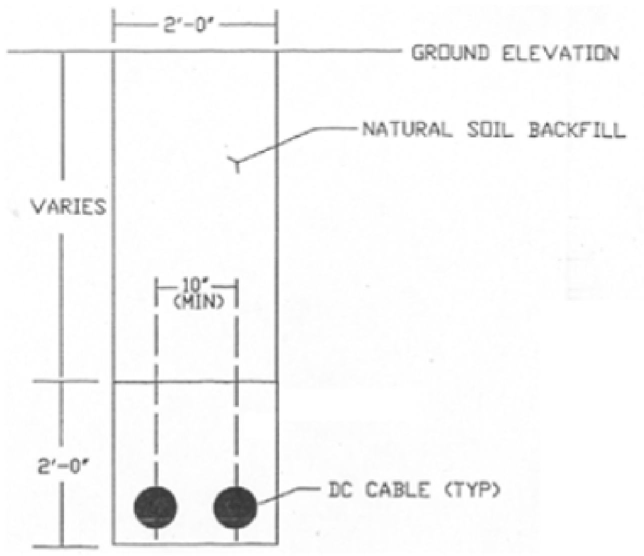


Figure 14 – Standard Trench—Direct Buried

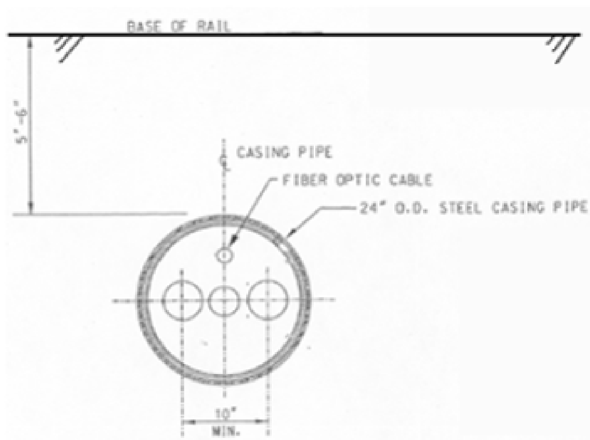


Figure 15 – Highways and railways crossing configuration

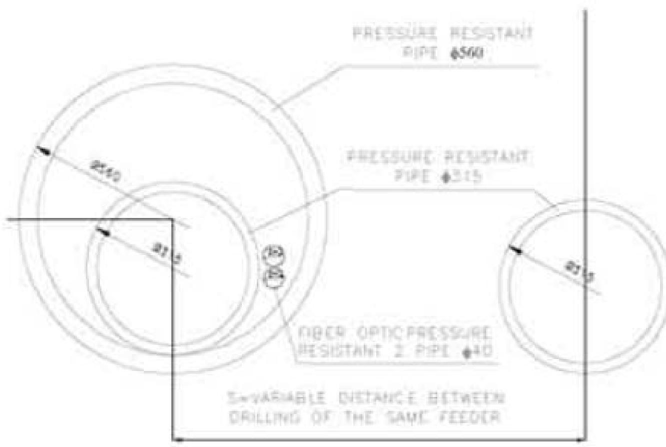


Figure 16 – HDD configuration for special crossings

The design parameters to carry out the cable study for these sections are described on the next table.

CASE	Ambient Temperature (ºC)	Thermal Resistivity (K·m/W)	Depth (ground level – cable edge) (m)	Pole Separation (m)
1. Standard Trench	25	1.2	1.8	0.25
2. Railways and Highways crossing configuration	25	1.2	2.2	0.25
3. HDD	18	1	20	10

Table 4 - Design Parameters on different route sections

At this stage full detail of crossing requirements are not known, hence design parameters will be confirmed after a complete analysis of the different crossings along the route.

In general HDDs will be filled with bentonite to allow better thermal evacuation and to reinforce the ducts resistance against the terrain pressures. However, for HDDs, parameters such as ambient temperature, thermal resistivity and cable spacing will be analyzed on a case by case basis.

2.2.1 Cable Data Sheets

Proposed cables have been evaluated to ensure they are able to guarantee the respect of the performance requirements related to this HVDC link. The general composition of this type of cables is described in the following paragraphs.

Conductor

In general a perfectly smooth conductor is assured with a uniform surface which minimizes the electric stress.

Normally for XLPE cables a round or miliken type copper section is used and for MI cables conductor consisting of annular segments made of copper closely laid up together around an inner rod.

Conductor screen

Conductor screens are designed with the purpose of offering a smooth surface over the conductor to avoid irregularities on the insulation. Thus, these screens avoid imbalances in the distribution of the electric field that could locally stress the insulation and reduce its life.

It may consist of a semiconductor or conductor material (mixture of polyethylene and carbon black or extruded XLPE or paper layer) which must be compatible with both the conductor and the insulation.

Insulation

Insulation is designed with the purpose of minimizing the dielectric stress level (measured in kV/mm) to extend the life of the insulation. The insulation must withstand maximum design temperatures so that its characteristics are not impaired as well as its lifecycle. In DC cables special care must be taken with the temperature drop on the insulation.

Principal types of DC cables insulation are:

- Cross-linked polyethylene (XLPE) super clean

- Mass Impregnated (MI) – and its development Polypropylene Paper Laminate (PPL)

Insulation screen

Insulation screen composition is similar to that used for the conductor screen and it must remain completely attached to the insulation to prevent irregularities in the distribution of the electric field. Insulation screens may include a moisture barrier that can also provide a smooth contact to the metallic screen.

Metallic sheath

The metallic screen is intended to provide a path for short circuit currents and confine the electric field inside it. Therefore, metal screens will be provided with sufficient section to conduct safely anticipated fault current.

Metallic screens are normally applied by continuous extrusion and is made of aluminum, copper or lead. Copper metallic screens are often made of copper wires.

Water blocking barrier

A water blocking barrier is normally attached to the metallic screen. Depending on the design, his may be made up of swelling tape and a metallic laminate (commonly aluminum).

Radial and longitudinal water blocking must be provided.

Outer sheath

An outer sheath is composed of a polyethylene (PE) sheath with outer semiconductor layer extruded jointly with de sheath.

In the following drawings typical components of XLPE and MI cables are described.

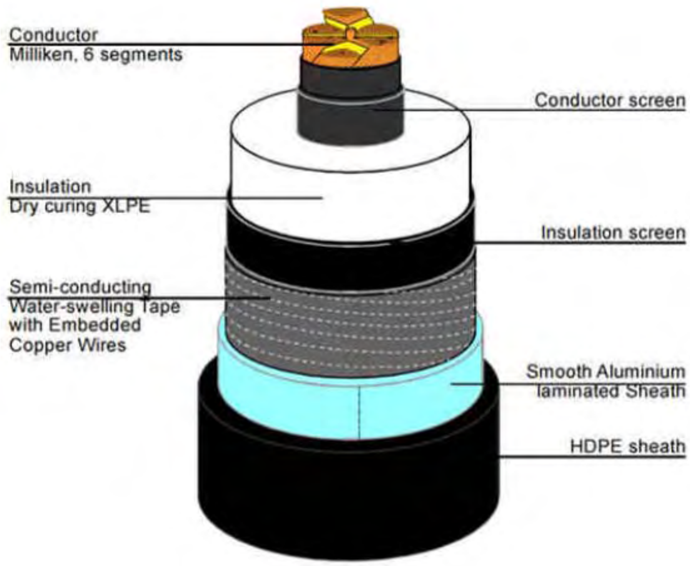


Figure 17 – XLPE cables general composition

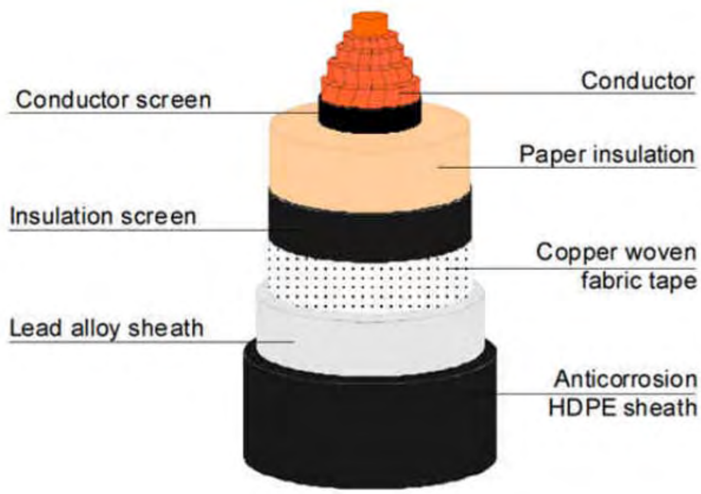
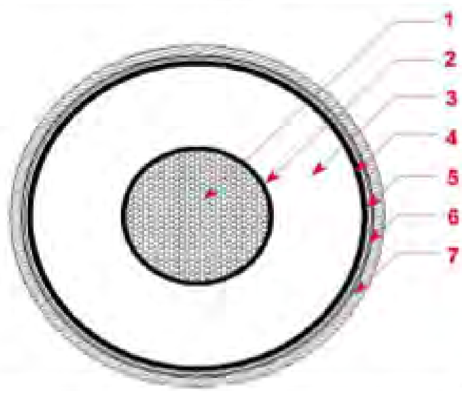


Figure 18 – MI cables general composition

- 320 kV DC XLPE insulated cable with 2500 mm2 copper conductor

Conductor Section		
A	*2500*	*mm^2*
Maximum Temperature at insulation		
T_{ins}	*70*	*°C*
DC Resistance of conductor at 20 °C		
R_0	*0.00725*	*Ω/km*
Temperature Coefficient of Resistance		
α	*0.00393*	K^{-1}



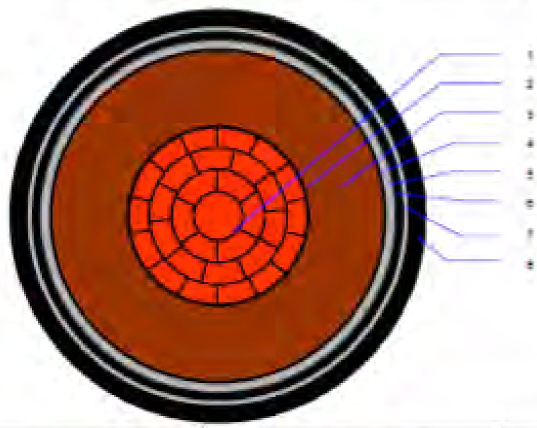
Item	*Description*	*Thickness (mm)*		*Nominal D (mm)*	
1	Conductor	-		D_c	56.5
2	Conductor Screen	Sp_{si}	*1.5*	D_{si}	59.5
3	Insulation	Sp_{is}	*21.5*	D_{is}	102.5
4	Insulation Screen	Sp_{se}	*1*	D_{se}	104.5
5	Extruded Lead Alloy Sheath	Sp_{Pb}	*3.5*	D_{Pb}	111.5
-	PE Sheath	Sp_{PE}	*3.5*	D_{PE}	118.5
-	Bedding tape	Sp_{tp}	*0.35*	D_{tp}	119.2
6	Galv. steel tape Reinforcement	Sp_{bl}	*0.6*	D_{bl}	120.4
-	Bedding tape	Sp_{ll}	*1.3*	D_{l}	123.0
7	PE + CG Serving	Sp_{serv}	*4.95*	D_e	132.9

Note: All dimensions only for indicative purpose

Table 5 – 320 kV DC XLPE 2,500 mm2 cable data sheet

- 500 kV DC MI insulated cable with 1600 mm2 copper conductor

Conductor Section		
A	*1600*	*mm²*
Maximum Temperature at insulation		
T_{ins}	*55*	°C
DC Resistance of conductor at 20 °C		
R_0	*0.0113*	Ω/km
Temperature Coefficient of Resistance		
α	*0.00393*	K^{-1}



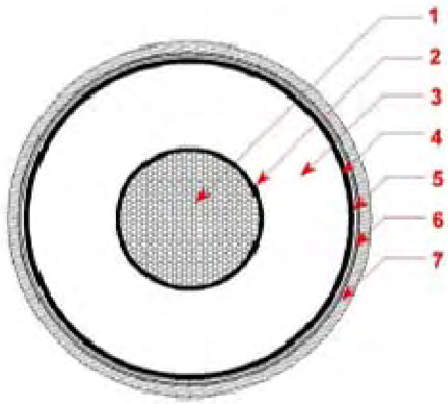
Item	Description	Thickness (mm)		Nominal D (mm)	
1	Conductor	-		D_c	45.2
2	Conductor Screen	Sp_{sc}	1.5	D_{sc}	48.2
3	Insulation	Sp_s	17	D_s	82.2
4	Insulation Screen	Sp_{se}	1.4	D_{se}	85.0
5	Lead Sheath	Sp_{Pb}	3.5	D_{Pb}	92.0
6	PE Sheath	Sp_{PE}	3.5	D_{PE}	99.0
-	Bedding tape	Sp_{tb}	0.35	D_{tb}	99.7
7	Galv. steel tape Reinforcement	Sp_{bt}	0.6	D_{bt}	100.9
-	Bedding tape	Sp_t	1.3	D_t	103.5
8	PE + CG Serving	Sp_{serv}	4.95	D_e	113.4

Note: All dimensions only for indicative purpose

Table 6 – 500 kV DC MI 1,600 mm2 cable data sheet

- 500 kV DC MI insulated cable with 1600 mm2 copper conductor

Conductor Section		
A	1000	mm^2
Maximum Temperature at insulation		
T_{ins}	90	°C
DC Resistance of conductor at 20 °C		
R_0	0.0176	Ω/km
Temperature Coefficient of Resistance		
α	0.00393	K^{-1}



Item	Description	Thickness (mm)		Nominal D (mm)	
1	Conductor	-		D_c	35.7
2	Conductor Screen	Sp_{si}	0.5	D_{si}	36.7
3	Insulation	Sp_{is}	30	D_{is}	96.7
4	Insulation Screen	Sp_{se}	0.6	D_{se}	97.9
5	Long. Water Penetration	Sp_{Pb}	3.5	D_{Pb}	104.9
-	Lead Alloy extruded Sheath	Sp_{PE}	3.5	D_{PE}	111.9
-	Bedding tape	Sp_{tb}	0.35	D_{tb}	112.6
6	Galv. steel tape Reinforcement	Sp_{bl}	0.6	D_{bl}	113.8
-	Bedding tape	Sp_{l}	1.3	D_{l}	116.4
7	PE + CG Serving	Sp_{serv}	4.95	D_e	126.3

Note: All dimensions only for indicative purpose

Table 7 – 500 kV DC MI 1,600 mm2 cable data sheet

2.2.2 Communication Cables

Both converter stations will be communicated by a fiber connection with redundancy. Along the route each fiber will be allocated as far as possible within the trench to ensure that one healthy fiber will live in case of cable fault. The optical cables will terminate in the control building at the converter stations installed on a specific frame.

- Number of cables 2
- Number of fibers per cable 48
- Type of fibers According to ITU-T Recommendation G.652

Being a long fiber route may imply fiber signal mitigation because of the cable length. In the case of straight fiber communication impossibility a fiber signal regenerator feeder by LV and with batteries will be place in a suitable fiber joint along the route to guarantee the fiber signal strength at both ends.

2.2.3 Distributed Temperature Sensing – DTS

The HVDC cable temperature will be monitored in the total route, by means of a measuring system (one per independent system) based on temperature sensors, installed for a length equal to that of the HVDC cables, directly on the external surface of the HVDC cables or inside a pipe close to the pipe where is installed the HVDC cables.

The temperature values will be transmitted to the control room of the converter stations, visualized locally on a cabinet in the control room, and made available to the control and supervision system of the HVDC link.

DTS is a branch of condition monitoring whereby the temperature of an optical fiber, at any point along its route, can be determined with a high degree of accuracy. Essentially, the DTS operates by firing a laser pulse down an optical fiber; as the pulse travels along the fiber, part of the signal is reflected back in the opposite direction. The temperature sensitive component of the "backscatter," as it is called, is then sampled with the time of sampling from when the pulse was originally transmitted being used to determine the point of measurement along the fiber. The combination of these points of measurement is used to develop a temperature profile of the optical fiber.

Figure 19 - Power cable with DTS cable attached

2.2.4 Cable Joints

Due to the limitations of cable manufacturing and transportation, as described above, cable

route is divided in cable sections to be reeled and transported to site. These cable sections are jointed on site to complete the cable route of the HVDC transmission link.

Depending on the technology of the proposed cable system, the jointing accessories and assembly vary considerably.

In the case of extruded XLPE insulation cables, cable joints are made up with a premoulded insulating body which is installed over both ends of cable in order to assure the main insulation continuity.

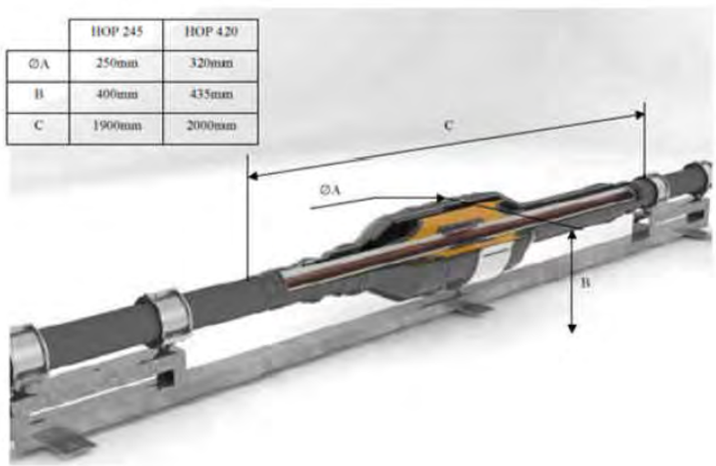


Figure 20 – XLPE Cable Joint

In the case of Mass-Impregnated insulation cables, there is no premoulded joint and the jointing process is a fully handicraft work. Therefore, these joints represent a virtual reinstatement of the original cable structure, minimising any changes in cable characteristics. This is a process that takes a longer time comparing to the XLPE cable jointing process and it is much more complex. This process consists of the following processes:

- Jointing the two conductor ends
- Reconstruction of the insulation using identical material to the used for the cable
- Reconstruction of the sheath using a shrunk sleeve
- Reconstruction of the outer sheath by means of a heat shrink

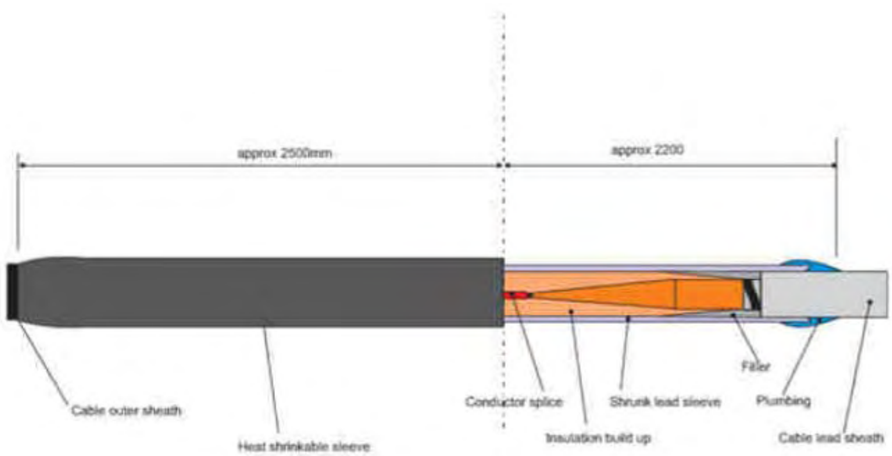


Figure 21 - MI Cable Joint

2.2.5 Cable Terminations

At each end of the route the power cables terminate by air insulated terminations.

The power transmission capacity, as well as the withstand short circuit current will be at least

the same as the HVDC cable. Terminations for the cables will be installed indoor, in “ad hoc” buildings of the converter stations foreseen for the HVDC converter yard. The terminations shall be capable to sustain the electrical, thermal, and mechanical stresses for a duration of 40 years.

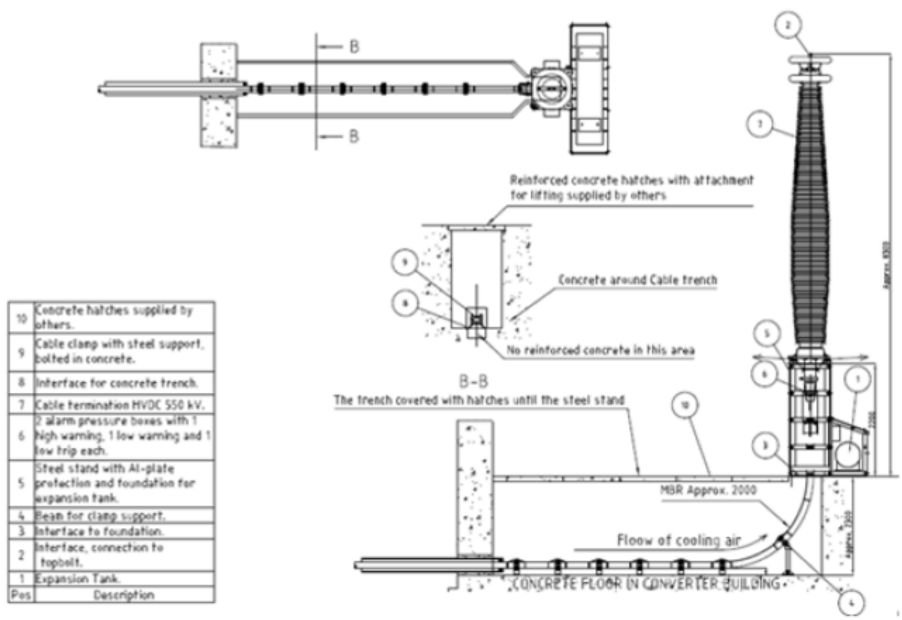


Figure 22 – Cable Termination Scheme

The main components of terminations are described below:

1. Insulation filling fluid: Oil or SF6. Pressure control devices will be required.
2. Top bolt in aluminium or copper: The diameter of the top bolt must be adequate to withstand the short circuit current of the conductor, as well as electrodynamics

stress, both in normal operation and in short circuit conditions and with its Corona shield in aluminum.

3. Interface foundation and cable clamp compression electrode. It must assure the sufficient mechanical protection to the joint in normal operation of the cable, in short circuit conditions and during assembly operations and must be provided of the guarantee the water tightness in the entrance of the cable into the termination .
4. Cable clamp compression electrode. It must assure the sufficient mechanical protection to the joint in normal operation of the cable, in short circuit operations and must be provided of the necessary devices to guarantee the water tightness in the entrance of the cable into the termination.
5. Plate base in aluminum. The connection to the cable shall be designed to resist electrodynamics stress produced during normal operation and during specified short circuit conditions. The box body shall be prepared for the correct connection with the support of the termination.
6. Oil tank pressure alarms (if needed)
7. Polymeric external insulator: Upper and lower flanges shall be correctly sealed to the external insulator in order to prevent leaks of the insulating fluid. It must assure an appropriate protection against corrosion of any element exposed to air.
8. Concrete trench or duct within the building.
9. Clamps along the trench
10. Concrete hatches.

The terminations are assembled over small support insulators to insulate the screen from the metallic structure. With these insulators it is possible to make the outer sheath tests. The cable screen is connected to the sealing end base terminal, and through it is connected to earth. The high voltage connection is done on the top connector which is protected with a corona shield.

2.3 Cable Installation

Following cable and accessories manufacturing process, cable installation will simultaneously take place during the project development optimizing the delivery plan of the project. For this purpose the cable route will be studied and manufacturing and installation plan will be developed to the best detail.

This way, cable sections are defined along the route and manufacturing plan is defined according to the forecasted optimum cable laying seasons. This process enables the possibility of overlapping manufacturing and installation phases, thus minimising completion time of these phases of the project.

Cable installation process includes the following processes:

- Cable transportation
- Trench digging
- Special civil works: crossings, HDDs
- Cable laying
- Joints assembly
- Terminations assembly

2.3.1 Cable Transportation – Estimated Cable Package

Manufactured cable is transported from the factory to the site on cable drums. Due to the fact the cables considered for this project are relatively large and heavy, the cable length to be transported on each drum is limited.

The key factor on the limitation of cable length to be reeled is the weight of the cable. For the cables proposed the average length of drums estimation is the following:

- 500 kV DC MI: Aprox. 1.000 m/drum
- 320 kV DC XLPE: Aprox. 800 m/drum

This is an estimated average length which could be increased or decreased depending on the installations facilities and transport.

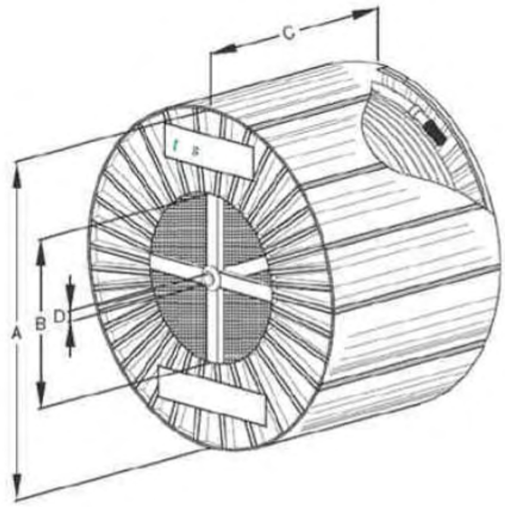


Figure 23 - Cable drum

Average dimensions of drums for cable transportation are described on the following table.

Type of drum		42 x 23 x 27
A,	mm	4.200
B,	mm	2.300
C,	mm	3.000
D,	mm	150
Weight of empty drum, kg		6.000
Weight of loaded drum, kg		40.000

Table 8 – Dimensions of cable drums

The estimation of the average cable length per drum results on the number total number of drums to be transported for cable installation, hence, the number of joints to be installed along the cable route.

The estimation of section lengths will be studied in deep, once the cable route is studied, in order to define the optimum section lengths, and according to this, the number of drums and joints. Main considerations for the definition of the optimum section lengths are:

- Best compromise between the number of drums and their size
- Earthing length limitation to sheath corrosion effect
- Number of joints

- Location of joint bays
- Cable laying

	±500 DC 1600 mm^2 Cu	±320 DC 2500 mm^2 Cu	±500 DC 1000 mm^2 Cu
Unit weight (kg/m)	41	48	32
Number of drums	250	312	235
Length per drum (m)	1.000	800	1063

Table 9 - Estimation of cable drums

Drums of this weight and size have to be handled with great care. To minimize the risk to the safety of persons employed on the site, a proper methodology will be adopted in order to minimize the number of times that the drums are handled during the transportation process.

For this project the drums will be delivered by ship to a port in the vicinity of the project. Then the drums will be collected by cable trailers and delivered to site for installation of the cable.

2.3.2 Track Characteristics

Main characteristics to be considered regarding cable route, cable design and cable installation are summarized in this section.

Start Point: North Converter Station will be located in the vicinity of New Scotland Substation

Final Point: South Converter Station will be located in the vicinity of the Hurley Substation

Approximate Length: 53.3 miles

Restrictions along the track. Restrictions / Standards Public Services (drawings): The studies based on trial holes information consider a maximum depth (from ground level to top cable edge) of 1.8m.

Minimum turning radius along the route: 50 x D_{cable}

Minimum turning radius at sealing end arrival: 40 x D_{cable}

Duct Dimension: Internal Diameter has to be 1.5 x D_{cable}

Joint bay position:

	±500 DC 1600 mm^2 Cu	±320 DC 2500 mm^2 Cu	±500 DC 1000 mm^2 Cu
Number of joints Aprox.	250	312	235
Number of joint bays Aprox.	125	156	118

Table 10 – Estimation of joints along the route

2.3.3 Trenching & Laying

The cables will be located, where possible, below the surface on the Thruway within the existing right of way. Where it is feasible to do so, the cables will be placed adjacent to the roadway shoulder. This will minimize the impacts on the travellers on construction to proceed safely.

Circuit will be buried in trenches along the Thruway. A typical trench cross below. The trench is typically 0,6 m wide and 1,8 m deep. It holds the two 500kV/320kV cables.

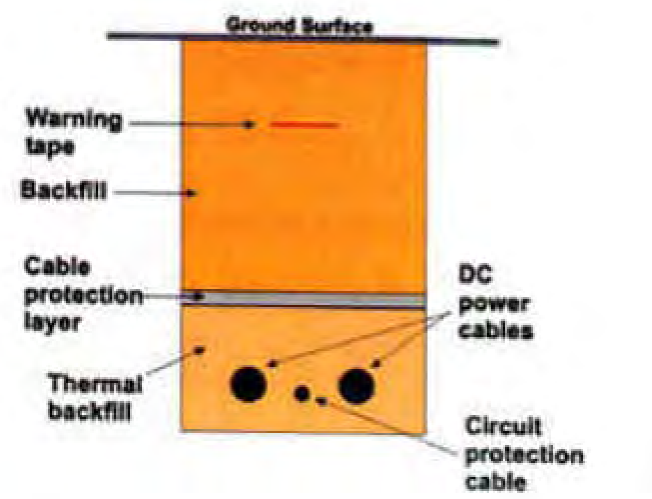


Figure 24 - Typical trench cross section for direct buried cables

The warning tape shown in the figure above provides a notification to contractors that high voltage cables lie underneath and that they should work with extreme care.

The backfill is usually the material that was removed from the trench during excavation.

The cable protection layer is usually made of reinforced concrete or an equally strong synthetic material and provides a physical protection barrier for the cables in the the warning tape is ignored.

The thermal backfill is a material that has good thermal properties and is used to prevent the cables from overheating by dispersing the heat generated by each cable conductor into the surrounding soil.

The circuit protection cable is usually an optical fibre cable that is used to send circuit control and protection signals from one end of the route to the other.

During the construction stage, purpose-developed machinery will be used to minimize excavation and cable installing times.

Working within the Thruway right-of-way will require special safety training and Personal Protective Equipment during the construction.

All construction activities will comply with the requirements of the New York State Thruway Construction Specifications and Requirements. The location and scheduling of work activities will be approved by the Thruway in advance and work will be scheduled to minimize impact on the travelling public.

Detailed Maintenance and Protection of Traffic Plans for each segment of the work will be prepared and submitted to the Thruway for approval prior to beginning work. For the most part, construction work activities will be performed in the daylight hours. Any lane or shoulder closures will be minimized and only used when necessary.

The daily construction work hours will generally be between 7 AM and 7 PM. When it is necessary to reduce or change these hours due to traffic volume and safety needs, the hours will be reduced or changed accordingly.

Staging areas will be installed within the Thruway right-of-way. These areas will primarily be close to the existing entry points to the Thruway. They will be developed for the project and restored upon the completion of construction activities. Construction field offices, parking, first aid facilities and equipment and material storage will be located at these points and daily activities will be staged from these locations.

Prior to the start of any excavation activity, the New York State One Call System will be contacted to locate any utilities along the proposed route. These utilities will be located in the field, and where necessary, test pits excavated to determine the exact locations.

Cables will be installed using a trenching machine or excavator, as necessary, to remove the existing soil/rock. The trench will be approximately 2 feet wide and 6 feet deep. The trench will follow the existing contours along the Thruway.

At some locations along the Thruway, rock instead of soil will be required to be removed. Depending on the extent and hardness of the rock, removal will be done using mechanical means.

The alignment of the cables will follow the shoulder where possible. At certain locations, it may be necessary to install the cable in the existing paved shoulder. In these locations, additional Maintenance and Protection of Traffic measures will be required. The surface area will be saw cut prior to trench excavation.

Installation of the cables will typically be performed utilising a mechanical trencher that will remove the existing soil or rock, place bedding material, install the cables, place select backfill around the cable and then complete the backfill using native soil. The installation activities will be continuous with complete sections being excavated, cable installed and backfilled in the same day.

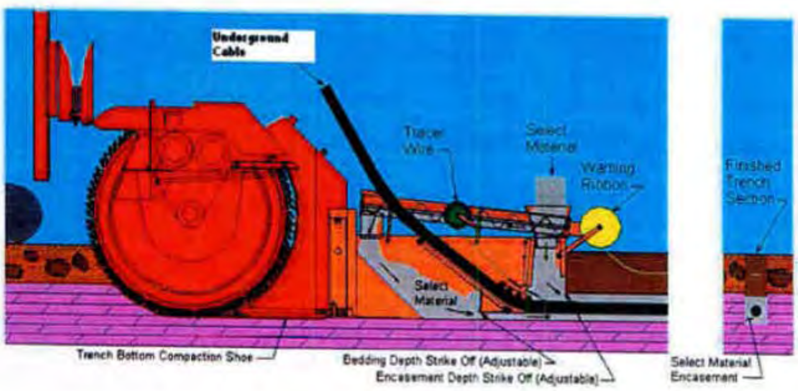


Figure 25 - Cables installation performed utilizing a mechanical trencher

The carbide toothed wheel trenches through the existing ground (rock, concrete, asphalt pavement, loose stone or sand, hard fill, boulders, wet soil, gravel, etc.)

The only area disturbed and material excavated is from the relatively narrow trench. The trench bottom compaction shoe flattens and compacts the bottom of the trench.

The laying box is connected to and pulled along through the trench by the compaction stone. It is connected in such a way that changes in direction both up and down and from side to side are not a problem. The laying box holds back the sides of trench, keeping out all debris.

The utility or utilities are fed down through the laying box by means of rollers or chutes, as appropriate, to the proper depth. Once the laying box passes and the utility or utilities are installed, the trench can be backfilled.

If select bedding or backfill is required, it can be accomplished in a number of ways. For sand, stone or other relatively dry material, the Select Material Transfer Cart is used. The select material is placed into the can, which is connected to and pulled along by the trencher, as the installation progresses.

Figure 26 - Selected material placed into the can in order to be installed

Concrete or flowable fill can be directly deposited into the laying box material hopper from the ready mix or flows fill trucks.

Figure 27 – Concrete deposited into the laying box material

The bedding is placed to the desired depth by the adjustable Bedding Depth Strike Off. The utilities are then placed down onto the bedding towards the rear of the laying box where select material encases the utilities.

Figure 28 - Bedding placement

In locations where there are interferences to the trenching operations such as bridge abutments, streams and roadways, sleeves will be jacked under the obstruct cables will be pulled through the sleeve.

Where cable joints are required, it will be necessary to excavate additional areas to perform jointing activities. A concrete mud slab will be placed in the joint area to provide a stable work platform. Once the joint is completed the area will be backfilled with select material around the cable and then native soil will be placed and the area seeded. The use of manholes for this purpose is not anticipated.

Figure 29 – Area backfilling and native soil will be placed

2.3.4 Jointing & Sealing Ends

The assembly of joints and terminations is made in order to achieve the continuity of the cable between converters. As explained before, the typology of these accessories change depending on the technology of the cable. For extruded XLPE manufactured accessories are utilized, while for mass-impregnated insulated cables this process is a fully handicraft work.

In terms of required time for accessories installation on site for extruded XLPE insulated cables, around five days are necessary to install one accessory for one jointer team. In the case of mass-impregnated insulated cables this timescale can be significantly increased due to the complexity of the process.

2.4 Cable System Testing

In case of being awarded is Iberdrola USA's intention to carry out the following set of test before,
along and after the project. All tests will be according to Cigre, Electra recommendation for
HVDC cable and accessories testing recommendations or IEC standards.

Prequalification Tests will be performed only if the cable supply has no demonstrated previous experience in any project for the insulation features offered in order to establish the
long term insulation integrity of a cable system (i.e. cable and accessories) under DC conditions.

Cable and at least one of each type of accessory should be tested (including one factory joint). The minimum duration of the test period will be 360 days at least.

As the converter technology is VSC where voltage polarity reversal cannot occur polarity reversal tests are not necessary.

The tests that are performed during the 360 days at least testing period are:

- Load cycle: Positive voltage at 1.45Uo
- Load cycle: Negative voltage at 1.45Uo
- High load: Positive voltage at 1.45Uo
- High load: Negative voltage at 1.45Uo
- Zero load: Positive voltage at 1.45Uo
- Zero load: Negative voltage at 1.45Uo, both systems

At the end of the 360 day period, switching and lightning impulse tests will be preformed. The
tests to will be performed by an independent laboratory or, if they are performed in a manufacturer's own laboratory, for them to be observed and verified by an independent

witness.

Type Tests will be carried out for cable and accessories (including factory made joints) should be tested together as a system. Type tests are split into two distinct areas; nonelectrical
and electrical.

Non-electrical test will be defined at the tender stage according cable installation special features foreseen such us:

- Unusually low ambient temperature (such as an in-air installation would see during the winter period)
- Installation and burial method; direct, in ducts, in troughs, etc.
- Bridge expansion joint crossings
- Areas exposed to high vibration

The principal electrical tests are:

- Load cycle tests: performed at 1.85Uo under positive and negative polarities
- Superimposed surge voltage test: performed at Uo with UP2,S then -UP2,0 then -UP2,S then UP2,0 superimposed
- Superimposed lightning impulse test will not be performed as the system will not be exposed to direct or indirect lightning strikes
- Negative dc test: 2 hours at –UT

If type test has been performed by the cable supplier for one equal specific system type test will avoided only if the previous contract fulfils the following points:

- Designs, manufacturing processes and service conditions are in all respects equal
- In service voltages as given above are equal or less
- Mechanical stresses are equal or less
- Conductor cross-section is equal to or within the range of that previously tested
- Maximum conductor temperature is equal or less
- Maximum electrical stresses are equal or less

- A system tested for LCC systems is qualified for VSC systems but not vice versa.

The tests will be performed by an independent laboratory or, if they are performed in a manufacturer's own laboratory, for them to be observed and verified by an independent witness.

Routine Tests will be performed on every delivery length of cable. A negative DC voltage
1.85·Uo shall be applied between conductor and screen for 15 minutes. Then the cable must be let deenergized during 1 hour, before applying a positive DC voltage 1.85·Uo between conductor and screen for 15 minutes.

The routine tests will be witnessed by Iberdrola USA or their representative.

Mechanical Routine Testing will be carried out if necessary.

Coiling test will apply only to cables that are to be coiled during manufacture or installation. The test cable should be coiled in a shape with dimensions representative of those experienced during manufacture and installation. At least 8 complete turns of the coil should be laid. After coiling, a sample of cable should be checked for damage.

External Water Pressure Withstand Test is designed to ensure the cable can withstand the crushing load from the head of water.

Sample Tests will be performed on selected samples from a batch of contract cables and are destructive in nature.

Sample tests shall be carried out according to the sampling rules listed as follows:

1. Conductor examination	According to IEC 62067-10.4
2. Measurement of electrical resistance of conductor	According to IEC 62067-10.5

3. Thickness of insulation on outer sheath — According to IEC 62067-10.6
4. Measurement of thickness of metallic sheath — According to IEC 62067-10.7
5. Measurement of diameters — According to IEC 62067-10.8
6. Hot set test for XLPE insulation — According to IEC 62067-10.9
7. Measurement of capacitance — According to IEC 62067-10.10
8. Measurement of density of HDPE insulation — According to IEC 62067-10.11
9. Lightning impulse voltage test followed by a power frequency voltage test — According to IEC 62067-10.12
10. Water penetration test — According toIEC62067-12.5.14
12. Tests for determining mechanical properties of insulation — IEC 62067 Paragraph 12.5.2
13. Tests for determining mechanical properties of outer sheaths — IEC 62067 Paragraph 12.5.3
14. Shrinkage test for PE, HDPE and XLPE insulation — IEC 60840 Paragraph 12.4.13
15. Shrinkage test for PE outer sheaths — IEC 60840 Paragraph 12.4.14

After installation tests will be performed in the installed HV cable system to a negative polarity DC voltage -1.45·Uo for 15 min.

Testing of Accessories will be carried out depending of the cable insulation type (XLE or MI). Accessories that are either filled with a low viscosity fluid that permeates throughout the accessory and fills any voids or, in the case of a mass impregnated system, are of a low stress design will be tested.

In an extruded system, accessories are likely to be of the premoulded or prefabricated design and, based on HVAC experience, are prone to failure as a result of discharge. While it is recognized that the stress distribution within DC accessories is different and failure mechanisms are likely to be different, accessories are still considered to be the weakest link, and it is recommended that accessories should undergo pre-dispatch routing tests.

Suitable detailed test requirements will need to be developed but it is considered that testing of key accessory components such as rubber mouldings should include the following:

- High voltage test
- Partial discharge test (under ac)
- X-ray examination
- Ultrasonic examination

Tests for telecommunication cables will also be carried out. Acceptance tests will be done for each of cable typologies in the supply, these tests shall be carried out.

- Spectral attenuation for 20% of the drums
- Chromatic dispersion for 20% of the drums
- PMD at for 20% of the drums
- Attenuation measurements by reflectometry from both ends for every fibre

At the end of installation testing after laying, on the telecommunication cables, the following tests shall be performed:

- Attenuation measurements by reflectometry from both ends for every fibre
- Attenuation measurements by reflectometry for joints
- Power measurements from end to end for every fibre
- Pitched of the fibres and characterization of connectors in the ODF
- Visual inspection and checking of all caskets and all junction boxes installed

3. COMISSIONING

The commissioning stage of a HVDC link takes part once all the different equipment has been installed and tested, including the cable. It comprises each converter station testing as

well as the testing of the complete HVDC link.

The commissioning stage can be divided in the following processes:

- Pre-commissioning Tests
- Subsystem Tests
- Converter Station Tests
- End to end Tests

3.1 Pre-comissioning Tests

After installation, functional tests will be carried out on the components of the HVDC system including switchgear, measuring devices, transformers, reactors, filters, auxiliaries and communications. The individual manufacturer supplies these pre-commissioning procedures. On complex equipment manufacturers commissioning specialist will pre-commission the equipment in accordance to the written procedure and document the results. The documented results are then signed off by the commissioning specialist and the customer.

Once the pre-commissioning of the components has been completed and the precommissioning documents are signed, it is safe to energize them.

The on site pre-commissioning tests for control and protection cubicles, which have been routine tested and pre-commissioned at the factory, only require a visual check of the auxiliary supplies.

3.2 Subsystem Tests

The individual equipment is brought together in the subsystem testing stage up to a point where all equipment works together correctly as a functional unit.

The tests should be carried out in such a manner that commands are generated and indications checked at the operator controls. Response to commands generated at the HMI shall be carried out correctly by the equipment. Indications from the equipment should show up correctly on the operator's workstation monitor in the form of on/off, open/closed, in transition or position.

The subsystem tests of the communication systems, LAN and field bus must prove that all participants connected to these busses are communicating successfully. The bus loading is measured and documented.

The components connected to the master clock system are checked to verify the accuracy of the time synchronization.

3.3 Converter Station Tests

The station tests follow the subsystem tests. While in the subsystem tests several commissioning tasks could be carried out in parallel, here the commissioning tasks at each station must be carried out sequentially. It is still possible to commission the two stations in parallel at this time with the exception of a few inter-station tests. These tests include:

- Off Voltage Converter Station Tests
- Energised Converter Station Tests
- Transmission Tests

3.4 End to end Tests

The system tests shall demonstrate that the HVDC system operates together with the AC systems correctly over the specified operating range in steady state as well as during transient conditions.

Standards

The project scope is composed in general by the two converter stations and the cable system.

The proposed solution will be designed, installed and tested with reference to internationally recognized standards, techniques and best practice. Most power systems have a number of unique features and, in order to ensure maximum system reliability, local project amendments to each piece of published work will be made as appropriate.

In general, reference will be made to IEC Standards and technical documents (Electra brochures) related to electrical transmission systems.

In addition, standards published by the New York Independent System Operator's (NYISO)
design requirements, the National Grid, New York State Power Authority and ConEd's Interconnection Standard for Transmission Facilities may be used as applicable.

The facilities will meet all applicable guidelines or standards of the Association of Edison Illuminating Companies (AEIC) Standard CS-7; Insulated Cable Engineers Association (ICEA) S-66-524; American Society of Testing and Materials (ASTM) Standard B-3 and Institute of Electrical and Electronic Engineers (IEEE). System design will comply with applicable sections of the latest version of National Electrical Code (NESC) and the National
Electric Code (C2) all as applicable. Also publications issued by the International Council on
Large Electric Systems (CIGRE) may be used. Pertinent design standards would include but
not be limited to the following ones:

[1] IEC 60076 – 6 "Power transformers – Part 6: Reactors"

[2] IEC 60633 “Terminology for high-voltage direct current (HVDC) transmission”
[3] IEC 61378 – 2 “Convertor transformers – Part 2: Transformers for HVDC applications”
[4] IEC 61378 – 3 “Converter transformers – Part 3: Application guide”
[5] IEC 61803 “Determination of power losses in high-voltage direct current (HVDC) converter stations”
[6] IEC 61975 “High-voltage direct current (HVDC) installations – System tests”
[7] IEC 62501 “Voltage sourced converter (VSC) valves for high-voltage direct current (HVDC) power transmission – Electrical testing”
[8] IEC PAS 62344 “General guidelines for the design of ground electrodes for high-voltage
direct current (HVDC) links (NPPAS)”
[9] IEC PAS 62544 “Active filters in HVDC applications”
[10] IEC TR 62001 “High-voltage direct current (HVDC) systems – Guidebook to the specification and design evaluation of A.C. filters”
[11] IEC TR 61000 – 3 – 6 “Electromagnetic compatibility (EMC) – Part 3-6: Limits – Assessment of emission limits for the connection of distorting installations to MV, HV and
EHV power systems”
[12] IEC TS 60071 – 5 “Insulation co-ordination – Part 5: Procedures for high-voltage direct
current (HVDC) converter stations”
[13] IEC 60060 – x: “High voltage test techniques”
[14] IEC 60230 “Impulse Tests on Cables and Their Accessories”
[15] IEC 60229 “Tests on cable oversheaths which have a special protective function and are
applied by extrusion”
[16] IEC 60287 series: “Electric cables – Calculation of the current rating”
[17] IEC 60438: “Tests and dimensions for high-voltage d.c. insulators”
[18] IEC 61245: “Artificial pollution test on high voltage insulators to be used in d.c. systems”

[19] IEC 60168 “Tests on indoor and outdoor post insulators of ceramic material or glass for
systems with nominal voltages greater than 1000 V”
[20] IEC 60332-3-22 “Tests on electric cables under fire conditions – Part 3-22: Test for vertical flame spread of vertically-mounted bunched wires or cables – Category A"
[21] IEC 60811-x: “Common test methods for insulating and sheathing materials of electrical
cables”
[22] IEC 62067: “Power cables with extruded insulation and their accessories for rated voltages above 150 kV (Um = 170 kV) up to 500 kV (Um = 550 kV) – Test methods and requirements”
[23] IEC 62155 “Hollow pressurised and unpressurised ceramic and glass insulators for use
in electrical equipment with rated voltages greater than 1 000 V”
[24] IEC 60228: “Conductors of insulated cables”
[25] IEC 60885-2: “Electrical test methods for electric cables. Part 2 : partial discharge tests”
[26] IEC 60949: “Calculation of thermally permissible short-circuit currents, taking into account non-adiabatic heating effects ELECTRA 141, 1992 “Guidelines for tests on High Voltage cables with extruded insulation and laminated protective coverings”.
[27] IEC 60250: “Recommended methods for the determination of the permittivity and dielectric dissipation factor of electrical insulating materials at power, audio and radio frequencies including metre wavelengths”
[28] IEC 60793: Optical fibres - Part 1-1: Measurement methods and test procedures - General and guidance.
[29] IEC 60793-2: Optical fibres: Product specifications - General.
[30] IEC 60793-2-50: Optical fibres: Product specifications – Sectional specification for class B single-mode fibres
[31] IEC 60794-1-1: Optical fibre cables: Generic specification - General.
[32] IEC 60794-1-2: Optical fibre cables: Generic specification - Basic optical cable test procedures

[33] IEC 60794-3: Optical fibre cables: Sectional specification - Outdoor cables.
[34] IEC 60794-3-10: "Optical fibre cables: Outdoor cables - Family specification for duct, directly buried and lashed aerial optical telecommunication cables"
[35] IEC 60794-3-11: Optical fibre cables: Outdoor cables - Detailed specification for duct and directly buried single-mode optical fiber telecommunication cables.
[36] IEC 60794-5: Optical fibre cables - Part 5: Sectional specification - Microduct cabling for installation by blowing.
[37] IEC 60141 Ed 3 Sept 1993 Tests on oil-filled and gas-pressure cables and their accessories
[38] ELECTRA 143,1992 "Calculation of temperature in ventilated cable tunnels - part 1".
[39] ELECTRA 144,1992 "Calculation of temperature in ventilated cable tunnels - part 2".
[40] ELECTRA n° 151, 1993: "Recommendations for electrical tests type, sample and routine
on extruded cables and accessories at voltages voltages > 150 (170) kV and ≤ 400 (420) kV".
[41] ELECTRA n° 173, 1997: "After laying tests on high voltage extruded insulation cable
systems"
[42] ELECTRA n° 32, 1974 Recommendations for tests on DC cables for a rated voltage up
to 550 kV.
[43] ELECTRA n° 72, 1980 Recommendations for tests of power transmission DC CABLES
for a rated voltage up to 600 kV
[44] ELECTRA n° 189, 2000: "Recommendations for tests of power transmission DC cables
for a rated voltage up to 800 kV".
[45] CIGRE Technical Brochure 496: "Recommendations for Testing DC Extruded Cable

Systems for Power Transmission at a Rated Voltage up to 500 kV"

[46] CIGRE guide: "System Tests for HVDC Installations"

[47] IEEE Std1378-1997 "Guide for Commissioning HVDC Converter Stations and Associated Transmission Systems"

ITU:

- ITU-T G.650.1: Definitions and test methods for linear, deterministic attributes of
single-mode fibre and cable.
- ITU-T G.650.2: Definitions and test methods for statistical and non-linear related
attributes of single-mode fibre and cable.
- ITU-T G.650.3: Test methods for installed single-mode fibre cable sections.
- ITU-T G.652: Characteristics of a single-mode optical fibre and cable.
- ITU-T G.655: Characteristics of a non-zero dispersion-shifted single-mode optical fibre and cable.

OTHERS:

- AEIC: Applicable codes and standards of the Association of Edison Illuminating Companies.
- ANSI: American National Standards Institute.
- ASTM: American Society for Testing and Materials.
- IEEE: Institute of Electrical and Electronics Engineers.
- NETA: International Electrical Testing Association.
- NEMA: International Electrical Manufacturers Association.
- ICEA: Insulated Cable Engineers Association.
- UL: Underwriters Laboratories.
- CIGRE TB 303, 2006, Working Group B1.06, "Revision of qualification procedures for HV and EHV AC extruded underground cable systems"
- *ICEA S-108-720-2004, 2004, Standard for Extruded Insulation Power Cables Rated Above 46 Through 345 kV, Insulated Cable Engineers Association, Inc., Carrollton, Georgia, USA*

- *AEIC CS9-06 – Specification for extruded insulation power cables and their accessories rated above 46kV through 345kVac*
- National Electrical Code (NEC = NFPA 70).
- National Electrical Safety Code (NESC = ANSI/IEEE C2).
- Life Safety Code (NFPA 101).
- All applicable OSHA standards.
- All applicable USCG regulations.

Section 4

Proposer Experience

Business History

Experience in Developing, Financing, Constructing and Operating Transmission Facilities

Familiarity and Experience with NYISO Requirements and Its Membership Status with the NYISO

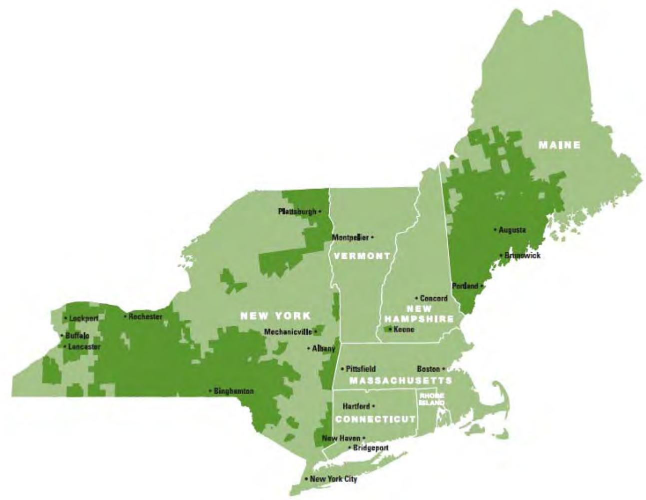
Environmental Permitting Experience

Project Management Team

Existing Electric Transmission Facilities Owned and/or Operated by the Proposer and Its Affiliates

Proposer Experience

Business History



Iberdrola USA, and its parent Iberdrola S.A., bring tremendous experience and investment capabilities to New York. Iberdrola is an energy services and delivery company that serves more than 2.4 million customers in upstate New York and New England through its five operating companies:

- **Central Maine Power (CMP)**
  Electricity delivery, Augusta, Maine
- **Maine Natural Gas (MNG)**
  Natural gas delivery, Brunswick, Maine
- **New Hampshire Gas (NHG)**
  Propane gas/air delivery, Keene, New Hampshire
- **New York State Electric and Gas (NYSEG)**
  Electricity and natural gas delivery, Binghamton, New York
- **Rochester Gas and Electric (RG&E)**
  Electricity and natural gas delivery, Rochester, New York

FACTS AND FIGURES:

Service Area	34,000 square miles
• Population Served	5 million
Electricity Service	62 counties, 962 cities, towns, villages, townships & plantations
• Electricity Customers	1,857,000
• Miles of Transmission Lines	8,275
• Miles of Distribution Lines	66,709
• Substations	905
• Electricity Delivered (2012)	31,570 gigawatt-hours
Natural Gas/Propane Service	41 counties, 377 cities, towns, and villages
• Natural Gas Customers	570,000
• Miles of Transmission Pipeline	123
• Miles of Distribution Pipeline	17,615
• Regulator Stations	875
• Natural Gas Delivered (2012)	111 million dekatherms
2012 Financial Results-Millions	
• Operating Revenues	$3,086
• EBITDA	$848
• Net Profit	$320
• Capital Investment	$955
Employees	4,085

Iberdrola USA is in the midst of a $1.4 billion upgrade of its transmission system in the state of Maine. The project, called MPRP, includes over 400 miles of new transmission lines, five new substations, and upgrades to numerous existing lines and substations. The company is about 1/3 of the way into the 5 year project and the project is on time and on budget. This project has created over 3,300 direct and indirect jobs for the state of Maine. Importantly, the project's DART rate (a measure of safety incidents) is .09 through March 2012 vs. a national average of 2.1. The completion of this project in early 2015 fits well with the likely construction schedule for this proposal.

Iberdrola is also a leader in the utilization of technology. For example, the MPRP project will be fully compliant with IEC 61850, an international best practice standard for substation automation and communications. Iberdrola USA subsidiary, Central Maine Power, recently completed the full installation of automated or "smart" meters that will provide tremendous environmental and customer benefits. Consumers are able to better manage their energy usage. CMP eliminated over 2 million vehicle miles per year.

Our parent, Iberdrola S.A., is a global investor-owned company with experience forged over more than 150 years of history that provides service to 31 million customers in 38 countries and four continents.

After a significant process of growth and internationalization, which involved an investment of over $100 billion in the last eleven years, Iberdrola is today one of the five largest global utilities, the world leader in the wind sector, and the leading Spanish energy group.

Our 33,000 employees manage assets worth $130 billion that in 2011 produced revenues worth $42 billion and a net profit over $3.5 billion dollars.

Iberdrola will continue to grow its core businesses: power generation through clean technologies and the build up and management of transmission and distribution networks. In addition, the continuous improvement of operational efficiency will remain one of the basic foundations of the Group's activities.

The path to sustainable growth in size, efficiency and profitability has brought Iberdrola a number of international awards, such as the nomination as leading electric utility on the

“Global 100 Most Sustainable Corporations in the World”. In addition, Iberdrola has been member of the “Dow Jones Sustainability Index” for the last eleven years.

Iberdrola USA has a solid team of experts on board to assist in the permitting, design, and implementation of this transmission line. Iberdrola USA will work with Iberdrola Engineering & Construction (a subsidiary of Iberdrola) on the engineering design of the transmission line, The Cianbro Company for consultation and management of the EPC Contractor, Gilberti Stinziano Heintz and Smith, P.C., for any legal and permitting support services, and Spectra Environmental Group, Inc. for the environmental permitting aspects of this project.

Iberdrola Engineering & Construction

Iberdrola Engineering & Construction is one of the world's leading electrical engineering companies, with projects in more than 30 countries across Europe, Asia, Africa and America. In 2011, the Company's project portfolio was worth more than two billion euros. Iberdrola E&C provides services ranging from basic studies to “turnkey” projects, in the generation, nuclear, networks, and renewables sectors. In fact, Iberdrola E&C has been able to undertake more than 500 substations in 500kV, 230kV, 132kV and lower tension levels. In the transmission and distribution realm, Iberdrola E&C is an expert in analyzing and integrating new installations, designing new substations, designing cable lines (underground, as with this project, as well as aerial and submarine), as well as protections, control, and measurement tools.

At present, Iberdrola Engineering and Construction (IEC) has a very specialised group of engineering and project management staff working in different HVDC projects. The focus on HVDC began in 2011, when the Company decided to create a group of engineers with capabilities to work in HVDC projects within the Iberdrola Group and for third party customers. As a result of this, IEC has written more than 30 technical manuals, describing the different technical engineering activities related to HVDC projects, including LCC and VSC HVDC Converter Terminals, HVDC OHT Lines and Cables Transmissions and System Study requirements .

IEC has today a staff of 33 professionals working in the following different HVDC activities:

- Electrical Power System Studies
- Converter Engineering
- Converter Protection & Control
- Converter Main Plant
- Converter Project Design Plant
- Converter Civil Engineering
- Land and Submarine HVDC Cable Design
- HVDC OHT Line Design
- HVDC Project Delivery

The Cianbro Companies

The Cianbro Companies, a 100% employee-owned company, specializes in the construction of transmission, mechanical, and electrical projects. Cianbro is the managing member of the Atlantic Energy Partners, LLC, the developer of the Neptune Regional Electrical Transmission System. The Neptune Transmission System provides up to 600 MW of electric power from the PJM system to the LIPA grid on Long Island via a 500 kV, high voltage direct current cable running from Sayreville, NJ to New Cassel, NY. The Sayreville converter station takes alternating current (AC) power from the PJM system and converts it to DC power, while the Duffy Avenue station converts DC power back to AC for use on the LIPA system. The DC cable runs approximately 50 miles under the Raritan River in New Jersey and the Atlantic Ocean, and an additional 15 miles buried alongside the Wantagh Parkway. The Neptune Transmission System interconnects to PHM in Sayreville at the nearby First Energy substation, and interconnects to the LIPA system at the Newbridge Road substation in Levitttown. Since starting operation in mid-2007, Neptune has provided, on average, nearly 25% of the electric power used on Long Island.

Gilberti Stinziano Heintz and Smith, P.C.

Gilberti Stinziano Heintz and Smith, P.C. is a law firm specializing in clients in the energy field, including large, multi-plant power producers, natural gas pipeline operators, and electric transmission line developers. They have been counsel on power generation projects that total more than 5,000 MW of generating capacity and have counseled electric transmission companies on projects involving more than 450 miles of transmission line.

Spectra Environmental Group

Spectra was formed in 1993 and is an integrated company, a combination of Spectra Environmental Group, Inc. and its affiliate Spectra Engineering, Architecture and Surveying, P.C., along with the newest affiliate Spectra Subsurface Imaging Group, LLC. The professional corporation (P.C.) is licensed to perform Engineering, Architectural and Survey services within New York State. The co-owners of Spectra, Mr. Robert C. LaFleur and Mr. John H. Shafer, P.E., have over 50 years of experience in engineering, environmental analysis, planning and management.

Mr. LaFleur has over 30 years of experience in the environmental consulting field. During his career, he has served as project manager for a number of large, complex environmental permitting and remediation projects in New York State. Mr. LaFleur specializes in the preparation of permit applications and Environmental Impact Statements and is an expert in New York State environmental permitting regulations. Mr. Shafer, who has formerly held the positions of Chief Engineer at the New York State Department of Transportation (NYSDOT) and the Executive Director of the New York State Thruway Authority, has specific expertise in infrastructure engineering, environmental analysis, and planning. Together, the owners provide diverse project experience and a "hands-on" management style that creates the greatest value for Spectra's clients.

Spectra is a Capital District based firm with its corporate office in Latham, New York. Additional offices are located in Poughkeepsie and Syracuse, NY. Spectra's staff is composed of approximately 40 professionals and includes environmental engineers and scientists, hydrogeologists, civil engineers, computer mapping personnel and surveyors. Spectra has a diverse client base that includes local and state government, as well as private industry.

Spectra's environmental group assists energy-producer companies with the following related services:

- Permitting new electrical transmission lines
- State-level permitting processes
- SEQRA permitting
- National Environmental Policy Act (NEPA) services
- Title VII and Title X permitting
- Transmission lines
- Route selection and feasibility studies
- Environmental science studies including biological, wetlands, land use, cultural, and archaeological resources
- Visual resources
- Mapping and Geographic Information Systems

Spectra Environmental Group, Inc. is a self-certified Small Business Enterprise (SBE) with the federal government.

Experience in Developing, Financing, Constructing, and Operating Transmission Facilities

Iberdrola USA, and its parent, bring tremendous experience and investment capabilities to New York. At the end of 2012, Iberdrola USA had over $12.2 billion of assets, including $2.3 billion of transmission assets. Iberdrola USA finances these assets and all of its future capital investments with a combination of debt and equity. Iberdrola USA, and its subsidiaries, is able to leverage its strong investment grade credit ratings to attract low cost debt financing. In the last five years Iberdrola USA has made capital investments totaling over $1.7 billion.

Iberdrola USA's largest current transmission project is a $1.4 billion upgrade of its transmission system in the state of Maine. The project, called MPRP, includes over 400 miles of new transmission lines, five new substations, and upgrades to numerous existing lines and substations. The company is about 1/2 of the way into the 5 year project and the project is on time and on budget. This project has created over 3,300 direct and indirect jobs for the state of Maine. Importantly, the project's DART rate (a measure of safety incidents) is .09 through March 2012 versus a national average of 2.1. The completion of this project in early 2015 fits well with the construction schedule for this proposal.

Other significant recent transmission projects include the Rochester Transmission Project. This project was completed in 2008 and represented a $125 million investment in 38 miles of new and rebuilt 115kV Transmission. The Ithaca Transmission Project represents 30 miles of new and reconductored 115kV Transmission and a new 345/115 kV substation.

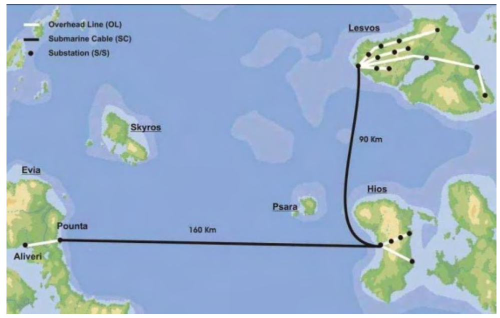
Iberdrola is also a leader in the utilization of technology. For example, the MPRP project will be fully compliant with IEC 61850, an international best practice standard for substation automation and communications. Iberdrola USA subsidiary, Central Maine Power, recently completed the full installation of automated or "smart" meters that will provide tremendous environmental and customer benefits. Consumers are able to better manage their energy usage. CMP eliminated over 2 million vehicle miles per year.

The following projects describe Iberdrola Engineering and Construction's experience in the technical design of transmission lines.

Mammoth HVDC Project, Greece

The first HVDC Project developed by Iberdrola Engineering & Construction was the feasibility study for the integration of large-scale wind power of the Islands Hios, 374

MW, Lesvos, 676 MW and Limnos, 586 MW to the Mainland Grid, in Greece, totalizing 1.6 GW Transmission.



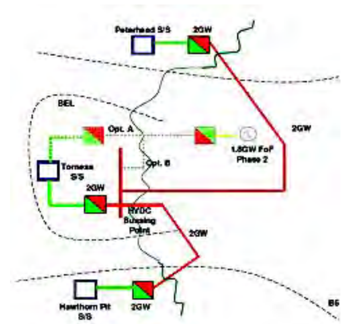
Western HVDC Link, Scotland and England

At present, Iberdrola Engineering & Construction is working for Scottish Power Energy Networks in the 2.4 GW HVDC transmission link between Scotland and England. The HVDC project includes around 370 km of route submarine HVDC Cable at 600 kVDC and two converter terminals designed with LCC HVDC Technology. The project will be delivered in 2016.

Eastern HVDC Link, United Kingdom

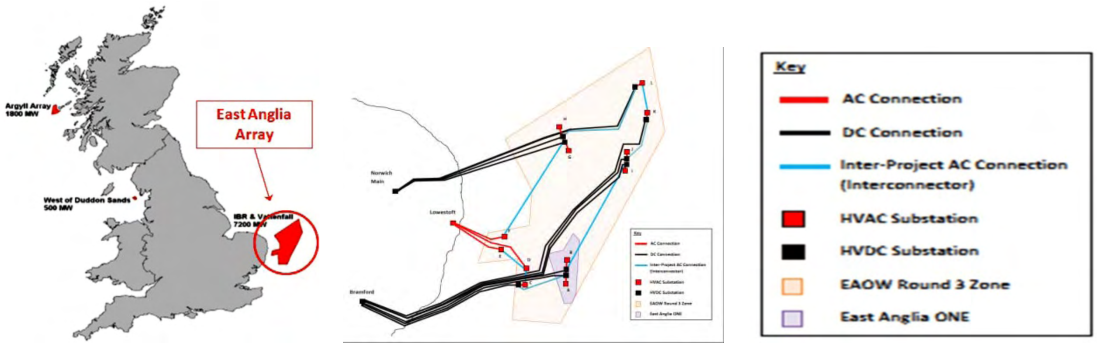
Iberdrola Engineering & Construction is working for Scottish Power Energy Networks in the definition and specification of the Multi-Terminal HVDC project of 1.8 to 2.0 GW that will interconnect by submarine HVDC cable Peterhead, in the Scottish Hydro

Electric Transmission (SHET) transmission area, with Torness, in the Scottish Power Transmission (SPT) transmission area and Hawthorn Pit, in the National Grid Electricity Transmission (NGET) transmission area. The HVDC project includes around 400 km of route submarine HVDC cable at a voltage level to be defined between 500 and 600 kVDC, three converter terminals designed with VSC HVDC technology and also an HVDC bussing station at Torness, required as the point of interconnection on the DC side for the two sub-sea cables and the Torness Converter Station. The project is currently in the feasibility stage and is expected to be delivered by 2019.



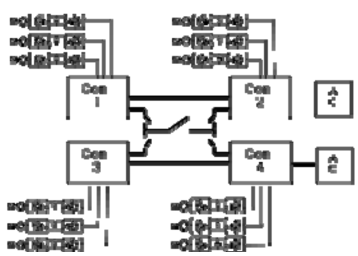
East Anglia Offshore Array, England

Iberdrola Engineering & Construction is working for Scottish Power Renewable (SPR) in the preparation and issuing of the invitation to tender for the HVDC aspects for of 1.2 GW, in the first phase of the interconnection of the East Anglia Offshore Array, which has a total capacity of 7.2 GW. The HVDC project will include onshore and offshore HVDC submarine cable and two converter terminals, most likely designed with VSC HVDC technology.



EU - Seventh Framework Programme

IEC is working for Iberdrola Renewables (IBR) in the presentation of the offer for the tender of the Project: “Beyond State of the Art Technologies for Re-Powering AC Corridors & Multi-Terminal HVDC Systems," belonging to the European Program: FP7-ENERGY-2013. This research project will investigate the electrical interactions between the HVDC link converters and the wind turbine converters in offshore wind-farms, and demonstrate the results in a laboratory environment using scaled models. One of the key objectives of the project is to demonstrate that multi-vendor capability of the various converters is achievable and how each converter will react under various scenarios.



Familiarity and Experience with NYISO Requirements and its Membership Status with the NYISO

Iberdrola USA, and its affiliate companies NYSEG and RG&E, have extensive familiarity with the NYISO, and its predecessor the New York Power Pool (NYPP). When the NYPP was founded in 1966 to provide statewide system oversight, in response to the Northeast blackout from the year before, NYSEG and RG&E were two of the seven founding partners. In 1999 the responsibilities of the NYPP were transferred to the NYISO. This transfer occurred to support the restructuring of the electric power industry that was occurring throughout this decade. NYSEG and RG&E had to go through the NYISO process, and today, as part of the NYISO, these two Iberdrola USA affiliate companies now participate as part of the shared governance system with the other investor owned utilities, generation owners, competitive suppliers, end-use customers, environmental parties and public power organizations. In this role Iberdrola USA and its affiliates has played an important leadership and participatory role on the numerous committees, sub-committees, task forces and working groups of the NYISO.

Environmental Permitting Experience

For more than twenty-five years, Gilberti Stinziano Heintz and Smith (GSH&S) has served the needs of clients in the energy field, including large, multi-plant power producers, natural gas pipeline operators, and electric transmission line developers, as well as the developers, installers and operators of various renewable energy systems and other smaller generating facilities. The firm’s understanding of, and experience with, the applicable financing structures, regulatory requirements, and governmental approvals needed for large infrastructure and commercial development projects in New York, including large scale energy generation and transmission projects, is unparalleled. From the initial planning and feasibility phases of a project through environmental review and permitting to completion of construction and beyond, GSH&S provides counsel and strategic advice to clients on every aspect of energy development.

GSH&S has successfully completed the permitting and environmental review for various power plants firing a wide variety of fuels and for hundreds of miles of transmission line in the state. The firm has served as lead counsel in several landmark cases under the State's Environmental Quality Review Act (SEQRA), including litigation establishing that certain previously approved industrial operations were "grandfathered" and not subject to review. GSH&S has also provided strategic legal counsel on the approvals needed for various major generation and transmission projects in New York, including, among others, a 130-mile underground electric transmission line, an aboveground 190-mile electric transmission line, and a 50-mile overhead electric transmission line.

Spectra has experience completing Title VII and Title X permit applications for energy-related projects, as well as DGEIS and Final GEIS development, SEQRA permitting, project siting, environmental impact review, and other related services. The following projects illustrate Spectra's past environmental permitting experience as it relates to power generation and transmission facilities:

Empire Connection

Statewide, New York State

Spectra prepared the Article VII application for the Empire Connection Project for a private client. The application was processed and received complete status by the PSC, but private capital funding was inadequate to construct the project. The Empire Connection Project was an ambitious energy project that would have supplied up to 2000 megawatts of power from the upstate electric grid to downstate metropolitan consumers.

The project contemplated two separate parallel conductor lines. One would connect Niagara Mohawk New Scotland – Alps line in Athens, Greene County, to a substation in the Ravenswood section of Queens. The second line would connect the New York Power Authority Gilboa - Leeds line in the Town of Coeymans, Albany County, to a substation in midtown Manhattan.

Spectra performed all civil and environmental analyses for locating the transmission route along the NYS Thruway and Major Deegan Expressway corridors. Converter stations were proposed to be located at Athens, Coeymans, the Bronx (near the Washington Bridge Harlem River crossing), and Spuyten Duyvil, as part of the project. All topics of interest to be included in Article VII applications were covered, including:

- cost of installation,
- benefits to the owner of the corridor ROW,
- visual and noise impacts,
- stormwater considerations, geology and hydrogeology,
- environmental justice and land use considerations,
- Phase 1 Environmental Assessment for the corridors, and
- construction access and staging impacts.

Spectra also prepared a GIS inventory to document utility and infrastructure easements throughout the Hudson River Valley between Albany and New York City for the Empire Connection Project. Spectra met the demands of a project schedule that was driven by the urgency for increasing the availability of energy from upstate producers to downstate users, and the timeframes of the Article VII permitting process.

Athens Generating Facility

Athens, Greene County, NY

Athens Generating is a 1,080 MW combined cycle generating facility located in the Town of Athens, NY. The facility was the first combined cycle electric generating facility subject to the PSC major power project certification review and approval process under Article X of the PSC law and regulations.

Spectra represented the interests of the Town of Athens by reviewing the Article X permit application and commenting upon the extensive issues in the application for the proposed Athens Generating facility. Spectra participated with local government to protect the interests of the town residents by conducting a complete environmental review and audit of the proposed 1160 MW project. In addition to modifications to the PSC certificate conditions, Spectra's involvement resulted in alteration of the permits issued by the New York State Department of Environmental Conservation (NYSDEC).

Statewide Wireless Network Permit Applications and EIS

Statewide, New York

Spectra served as the technical advisor to the New York State Office for Technology (OFT) in all aspects of environmental quality review process (SEQRA) for development and implementation of the $2 billion Statewide Wireless Network project. Spectra served both as OFT's consultant and as environmental compliance advisor. As the largest single technology project ever undertaken by the State of New York, the goal was to establish a statewide communication network to provide a secure, interoperable, communications system for all federal, state and local entities.

The five-year project proceeded in two distinct phases: comprehensive environmental review followed by individual site evaluation. The environmental review phase involved preparing the Generic Environmental Impact Statement (GEIS, Draft and Final) and other documents required for the SEQRA process. Spectra participated in scoping and the public participation aspects of SEQRA, including 16 hearings held across the state. To accommodate evaluation of up to 1100 antenna locations across the state, the scope of the GEIS covered a wide-range of issues, many of which reflected diverse regional interests, and addressed the alternative wireless communication technologies. To achieve the intent of a generic assessment, Spectra categorized and described virtually all of the natural and cultural resources in New York State, described the potential impacts of antenna site preparation, construction and operation on flora and fauna, historical, archeological and visual resources, aviation safety, human exposure to electromagnetic radiation, and other impact/receptor combinations, and evaluated the means of mitigating each potentially significant impact.

The second phase involved evaluation of individual antenna sites selected by the contractor. Spectra developed a selection hierarchy and a process for evaluating each site for consistency with the parameters established in the GEIS. Spectra visited approximately 50 sites to document the existing conditions, evaluated the contractors' environmental reports and proposed mitigation measures, and recommended the action to be taken by OFT, to approve the site selection or require further study.

The issues pertaining to the specific proposed sites typically centered on the potential visual and aesthetic impacts of the proposed wireless towers. The degree of public interest and number of site-specific activities made skillful management a critical component of the project.

Project Management Team

The participants of the project management team for Connect NY include Iberdrola USA; Iberdrola Engineering & Construction; The Cianbro Companies; Gilberti, Stinziano, Heintz, and Smith, P.C. (GSH&S) ; and Spectra Environmental Group, Inc. Iberdrola USA will be the overall project manager and will own and operate the project. Iberdrola Engineering & Construction will be responsible for the engineering, cost estimation and construction portions of the project. The Cianbro Companies will provide oversight with the EPC contractor. Spectra and GSH&S will provide all permitting and environmental support.

Robert D. Kump – Chief Executive Officer *(Iberdrola USA).* As CEO of Iberdrola USA since 2009, Bob Kump is responsible for leading the strategic planning and driving financial results for Iberdrola USA. Kump previously served as Iberdrola's CFO, a position he also held at Energy East before its acquisition by Iberdrola in 2008. Before joining the Iberdrola USA management team, Kump spent years in various executive positions at Energy East, including:

- Senior Vice President and CFO.
- Vice President - Controller and Secretary.
- Vice President - Treasurer and Secretary.
- Vice President and Treasurer.

Mr. Kump joined NYSEG in 1986 as a senior accountant and held progressively responsible positions there including director, investor relations, director, financial services, and treasurer. Kump became Treasurer of Energy East when it was formed as a holding company for NYSEG in 1998.

Before joining NYSEG, he served as a senior accountant with the audit group Peat Marwick Mitchell in Syracuse. Kump earned a bachelor's degree in accounting from Binghamton University and is a certified public accountant in New York State.

Thorn Dickinson – Vice President, Business Development *(Iberdrola USA)*. Thorn Dickinson is vice president of business development for Iberdrola USA. In this role, he is responsible for creating and supporting business development and growth initiatives for Iberdrola USA.

Mr. Dickinson has worked in the utility industry for over twenty-five years. Prior to his current position, he worked in transmission and distribution operations, resource planning, rates and regulatory, strategic planning, investor relations and risk management at Iberdrola USA, Energy East and NYSEG.

In these roles, Mr. Dickinson has worked on integrated resource plans, clean air compliance, industry restructuring, the Energy East acquisitions of RG&E and CMP, integration with Iberdrola S.A., the Maine Power Reliability Project and the sale of CNG, SCG and Berkshire Gas companies and numerous other non-utility businesses.

Mr. Dickinson earned a master's degree in business administration from Syracuse University, and a bachelor's degree in electrical engineering from Union College.

Jose Maria Torres – Chief Financial Officer *(Iberdrola USA)*. As vice president, finance and control, Jose Maria Torres manages all financial matters at Iberdrola USA. Mr. Torres joined the Iberdrola Group in 1997, and has served since in a series of executive roles including finance manager at Coelba in Brazil and control director at

Neoenergia in Rio de Janeiro. In 2003, Mr. Torres returned to Spain for a three-year stint as the CFO for the Sagunto Regasification Plant in Valencia.

Most recently Mr. Torres was the CFO of Medgaz, an Iberdrola company responsible for the design, contruction and operation of a deepwater natural gas pipeline stretching from Algiers to Europe via Spain.

Mr. Torres holds a bachelor's degree in economics and business from the Universidad Autonoma de Madrid, and a bachelor's degree in law from the Universidad Nacional de Educacion a Distancia (UNED).

Eduardo Mario Duchini Ramini – Power Systems Engineer *(Iberdrola Engineering & Construction)*. Mr. Duchini is a Senior Specialist of Power Systems, specializing specifically in transmission projects. He has more than 30 years of professional experience and has a degree in electromechanical engineering. Mr. Duchini was one of the key people responsible within Iberdrola Engineering and Construction for pushing and starting the HVDC business activities in the company due to his detailed knowledge of HVDC projects. His knowledge of HVDC technologies obtained during 2.5 years working at ABB HVDC Power Systems. Mr. Duchini worked on the feasibility study of the Amazon Electricity Transmission project in Brazil for the CPTA, analyzing and comparing HVAC transmission and HVDC transmission, associated HVDC tapping systems, and the HVDC overhead transmission lines crossing different Brazilian states.

William J. Gilberti, Jr., Esq. – Managing Partner; Senior Legal Advisor *(Gilberti Stinziano Heintz and Smith)*. Mr. Gilberti, CEO of the firm and co-chair of the environmental practice, is one of the foremost authorities on New York State environmental law and environmental litigation. Mr. Gilberti has successfully argued issues that have defined the contours of New York State environmental law. He is also experienced in appellate practice and has served as lead counsel in several cases, establishing important principles under New York State's Environmental Quality Review Act (SEQRA). His most recent projects include the build-out of the statewide wireless communications network and a proposal to construct the longest underground direct current electric transmission line in the world.

Brenda D. Colella, Esq. – Legal Advisor *(Gilberti Stinziano Heintz and Smith)*. Ms. Colella has a strong background in business litigation, environmental review and permitting, zoning, land use, and municipal law. Ms. Colella also counsels businesses on their needs with respect to regulatory compliance, including audits and certification processes. Ms. Colella's practice has historically focused on environmental law, eminent domain and water rights.

John F. Klucsik, Esq. – Legal Advisor *(Gilberti Stinziano Heintz and Smith)*. Mr. Klucsik's environmental practice has been focused on emissions regulations, water quality issues, hazardous waste disposal, contaminated site remediation, and compliance planning. He regularly lectures on the Clear Air Act, Title V, and air compliance programs. He was involved in the permitting of one of the largest steam-electric cogeneration stations in North America and assisted in converting several county-wide solid waste management systems to a private operation. Mr. Klucsik received the United States Nuclear Regulatory Comission's Special Achievement Award for work associated with the decontamination and decommissioning of the nation's only commercial plutonium reprocessing plant.

Robert C. LaFleur – Senior Environmental Engineer *(Principal of Spectra Environmental Group, Inc.)* Mr. LaFleur has over 39 years of experience as an expert in the environmental engineering and permitting field. Mr. LaFleur has experience providing expert testimony in both litigation and adjudicatory matters. He has expansive experience with the SEQRA review process, including taking the lead technical position at public meetings and hearings. He has also worked with industry leaders at the state level in the development of policy and legislation in the areas of environment and transportation. At Spectra, Mr. LaFleur is responsible for the preparation of permit applications and Environmental Impact Statements and expert testimony.

Paul Adel, PE – Senior Environmental Engineer ***(Senior Engineer at Spectra Environmental Group, Inc.)*** Mr. Adel has over 31 years of experience in environmental and structural engineering, including twenty years in environmental consulting and engineering services. On Spectra's prior power transmission projects, Mr. Adel has served as a technical advisor on all aspects of the environmental quality review process (SEQRA) and completion of Environmental Impact Statements. He has also provided expert witness testimony to present findings of environmental evaluations to the New York State Public Service Commission (PSC).

IBERDROLA USA

"Connect New York"

Organization Chart of Key Project Management Team Members

Chief Executive Officer
Robert Kump
Iberdrola USA

Project Management

Thorn C. Dickinson
Vice President, Business Development
Iberdrola USA

Financial Management

Jose Maria Torres
Vice President, Chief Financial Officer
Iberdrola USA

Transmission Design Team

Eduardo M. Duchini
HVDC Projects and Networks Business Development
Iberdrola Engineering & Construction

Gonzalo Echevarrieta Alvarez
HVDC Projects and Networks Business Development
Iberdrola Engineering & Construction

Environmental Permitting Team

Robert C. LaFleur
Senior Environmental Engineer
Spectra Environmental Group

Paul M. Adel, PE
Senior Engineer
Spectra Environmental Group

John D. Ciampa
Senior Environmental Scientist
Spectra Environmental Group

Engineering and Construction Support

Peter Vigue
Chairman & CEO
The Cianbro Companies

Ernest E. Kilbride
Vice President
The Cianbro Companies

Legal Team

William J. Gilberti, Jr., Esq.
Founding Partner
Gilberti Stinziano Hentiz & Smith

Brenda D. Colella, Esq.
Gilberti Stinziano Hentiz & Smith

John F. Klucsik, Esq.
Gilberti Stinziano Hentiz & Smith

Existing Electric Transmission Facilities Owned and/or Operated by the Proposer and Its Affiliates

Iberdrola USA is a major owner and operator of electric transmission facilities for over 100 years. We currently have over 8,000 miles of transmission lines under operation representing $2.3 billion of transmission assets at the end of 2012.

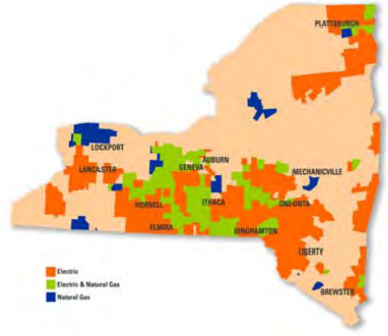
Our largest current transmission project is a $1.4 billion upgrade of our transmission system in the state of Maine. The project, called MPRP, includes over 400 miles of new transmission lines, five new substations, and upgrades to numerous existing lines and substations. The company is about 1/2 of the way into the 5 year project and the project is on time and on budget.

Iberdrola USA constructed a new 345/115kV substation consisting of two 345/115 kV, 200MVA LTC transformers, a 345 kV ring bus and a 115 kV bus arranged as a breaker-and-a-half scheme, located in Ithaca, New York. The existing 115kV line was rebuilt with larger conductor and a new 15 mile 115kV line was constructed. The project was placed in service on June 30, 2010 and the final project cost was $77.3M.

Iberdrola USA also completed the Rochester Transmission Project. Completed in 2008, the Rochester Transmission Project represented a $125 million investment in 38 miles of new and rebuilt 115kV Transmission.

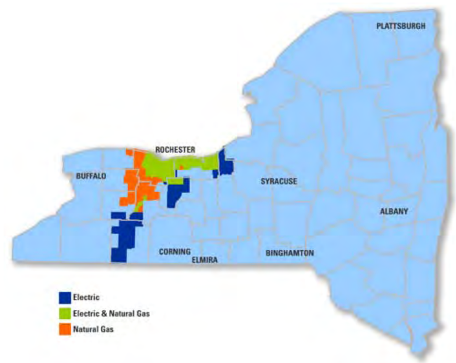
Iberdrola USA is currently developing the Rochester Area Reliability Project, a project that consists of 20.6 miles of new 115 kV transmission lines, the reconstruction of 2.0 miles of an existing 115 kV transmission line, a new 1.8-mile 345 kV transmission line, a new 345 kV/115 kV substation and improvements to three existing substations. The project is estimated to cost $250 million and is planned to be completed in 2015.

Iberdrola USA has two New York State affiliates: New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RGE). NYSEG serves 877,000 electricity customers and 261,000 natural gas customers across more than 40% of upstate New York. NYSEG's commitment to New York can be seen in its recent allocation of $2 million in emergency economic development funds to assist eligible businesses, municipalities, large residential establishments, agri-businesses and farms affected by Hurricane Sandy.



Map above: Service area of Iberdrola USA's affiliate New York State Electric and Gas (NYSEG)

RGE serves 368,000 electricity customers and 305,000 natural gas customers in a nine-county region centered on the City of Rochester. RGE is dedicated to the use of new technology to provide renewable energy to its customers, including aquaculture, erosion control, greenhouse technology, and optical methane detectors.



Map above: Service area of Iberdrola USA's affiliate Rochester Gas and Electric (RGE)

Together, NYSEG and RGE increased their generation of hydroelectric power by 14% in 2012, yielding CO2 savings equivalent to planning 55 million trees.

Section 5

Project Information

Company Details

Legal Status

Ownership Status

Sponsor Information

DUNS Number

Legal Form

Project Information

Company Details

Iberdrola USA
52 Farm View Drive
New Gloucester, ME 04260

Primary Contact: **Thorn Dickinson**
Vice President – Business Development
(207) 688-6362
thorn.dickinson@iberdrolausa.com

Legal Status

Corporation

Date of Incorporation

New York September 23, 1997

Jurisdiction of Organization

New York State

Indentification of Any Affiliates Having Any Role in the Project

None

Ownership Status

Iberdrola S.A., Iberdrola USA's parent company, is publically traded (in Spain)

Sponsor Information

Iberdrola USA, a subsidiary of global energy leader Iberdrola S.A., is an energy services and delivery company serving about 2.7 million customers in upstate New York and New England. Its primary subsidiaries are New York State Electric & Gas, Rochester Gas and Electric, and Central Maine Power. A new entity will be formed to manage the Connect New York project.

DUNS Number

04-186-6497

Legal Form

Not applicable

Section 6

Disclosure Statements

Disclosure Statements

In the last 5 years Iberdrola USA’s officers, directors or partners have not:

- Defaulted on, or was deemed to be in non-compliance with, any obligation related to the sale or purchase of power (capacity, energy and/or ancillary services), transmission, or natural gas, or was the subject of a civil proceeding for conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions, or collusive bidding or other procurement-or sale-related irregularities, or

- Been convicted of (i) any felony or (ii) any crime related to the sale or purchase of electric power (capacity, energy, and/or ancillary services), transmission, or natural gas, conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions, or collusive bidding or other procurement or sale-related irregularities.

Section 7

Financial Capacity to Complete and Operate the Proposed Project

A Demonstration of Financial Arrangements from the Proposer's Parent or Affiliate, Including Financing during Construction, Permanent Financing, and Capital Structure

A Schedule Showing All Major Projects Developed and Financed by Proposer and Its Affiliates in the Past 10 Years

Details of Any Events of Default or Other Credit Issues Associated with All Major Projects Listed in Proposer's Experience Above

Information Concerning the Proposer's Financial Condition

Four References from Prior Projects

Completed Financial Data Sheets

Financial Capacity to Complete and Operate the Proposed Project

A Demonstration of Financial Arrangements from the Proposer's Parent or Affiliate, Including Financing during Construction, Permanent Financing, and Capital Structure

Iberdrola USA will form a separate, wholly-owned legal entity whose sole purpose will be to construct, own and operate the Connect New York project. Iberdrola S.A., Iberdrola USA's parent, and Iberdrola USA will provide all equity capital requirements and any credit support necessary during the construction phase. Construction phase financing will be a combination of equity and bank-provided construction loans. Once construction is complete and the assets are placed in service, Connect New York will obtain its own stand-alone credit rating and access the debt capital markets to provide long-term debt capital financing. The capital structure will be approximately 50% debt and 50% equity.

Iberdrola S.A. is one of the largest utilities in the world with total assets of $125 billion. Iberdrola primarily operates in Spain, the U.K., the U.S. and Latin America. In the U.S., Iberdrola owns three regulated transmission and distribution utilities (NYSEG, RG&E and CMP) with combined assets of over $12 billion. Through its Iberdrola Renewables, Inc. subsidiary, Iberdrola owns and operates over 5GW of wind generation, making them the second largest renewable electricity generator in the U.S.

Iberdrola S.A. and its U.S. Subsidiaries maintain strong investment grade credit ratings. The Connect New York stand-alone entity is also expected to achieve an investment grade rating, ensuring access to the debt capital markets at a low cost.

	S&P	Moody's	Fitch
Iberdrola, S.A.	**BBB (Stable)**	**Baa1 (Negative)**	**BBB+ (Negative)**
Iberdrola, USA	**BBB (Stable)**	*N/A*	**BBB (Stable)**
NYSEG	**BBB+ (Stable)**	**Baa1 (Stable)**	**A- (Stable)**
RG&E	**BBB+ (Stable)**	**Baa2 (Stable)**	**BBB (Stable)**
CMP	**BBB+ (Stable)**	**Baa1 (Stable)**	**A- (Stable)**

A Schedule Showing All Major Projects Developed and Financed by the Proposer and Its Affiliates in the Past 10 Years

At the end of 2012 Iberdrola USA had over $12.2 billion of assets, including $2.3 billion of transmission assets. In the last five years Iberdrola USA has made capital investments totaling $3.5 billion, with over $1.7 billion being in transmission. In the last 10 years there have been hundreds of transmission projects developed by Iberdrola USA. Bellow are examples of a few of those major projects:

Maine Power Reliability Project

Our largest current transmission project is a $1.4 billion upgrade of our transmission system in the state of Maine. The project, called MPRP, includes over 400 miles of new transmission lines, five new substations, and upgrades to numerous existing lines and substations. The company is about 1/2 of the way into the 5 year project and the project is on time and on budget.

Ithaca Transmission Project

Construction of a new 345/115kV substation consisting of two 345/115 kV, 200MVA LTC transformers, a 345 kV ring bus and a 115 kV bus arranged as a breaker-and-a-half scheme. The existing 115kV line was rebuilt with larger conductor and a new 15 mile 115kV line was constructed. The project was placed in service on June 30, 2010 and the final project cost was $77.3M.

Rochester Transmission Project

The Rochester Transmission Project was completed in 2008 and represented a $125 million investment in 38 miles of new and rebuilt 115kV Transmission.

Rochester Area Reliability Project

A project currently under development, The Rochester Area Reliability Project, will include 20.6 miles of new 115 kV transmission lines, the reconstruction of 2.0 miles of an existing 115 kV transmission line, a new 1.8-mile 345 kV transmission line, a new 345 kV/115 kV substation and improvements to three existing substations. The project is estimated to cost $250 million and is planned to be completed in 2015.

Mammoth HVDC Project, Greece

The first HVDC Project developed by Iberdrola Engineering & Construction was the feasibility study for the integration of large-scale wind power of the Islands Hios, 374 MW, Lesvos, 676 MW and Limnos, 586 MW to the Mainland Grid, in Greece, totalizing 1.6 GW Transmission.

Western HVDC Link, Scotland and England

At present, Iberdrola Engineering & Construction is working for Scottish Power Energy Networks in the 2.4 GW HVDC transmission link between Scotland and England. The HVDC project includes around 370 km of route submarine HVDC Cable at 600 kVDC and two converter terminals designed with LCC HVDC Technology. The project will be delivered in 2016.

Eastern HVDC Link, United Kingdom

Iberdrola Engineering & Construction is working for Scottish Power Energy Networks in the definition and specification of the Multi-Terminal HVDC project of 1.8 to 2.0 GW that will interconnect by submarine HVDC cable Peterhead, in the Scottish Hydro Electric Transmission (SHET) transmission area, with Torness, in the Scottish Power Transmission (SPT) transmission area and Hawthorn Pit, in the National Grid Electricity Transmission (NGET) transmission area. The HVDC project includes around 400 km of route submarine HVDC cable at a voltage level to be defined between 500 and 600 kVDC, three converter terminals designed with VSC HVDC technology and also an HVDC bussing station at Torness, required as the point of interconnection on the DC side for the two sub-sea cables and the Torness Converter Station. The project is currently in the feasibility stage and is expected to be delivered by 2019.

Details of Any Events of Default or Other Credit Issues Associated with All major Projects Listed in Proposer's Experience Above

Iberdrola USA has had no events of default of other credit issues on any of our transmission projects.

Information Concerning the Proposer's Financial Condition

Please see the attached Financial Data Sheets for fiscal years 2010, 2011, and 2012 for Iberdrola USA, Inc. These sheets illustrate Iberdrola USA's current financial condition.

Four References from Prior Projects

William J. Allard
Project Manager
Burns and McDonnell
27 Pearl Street
Portland, ME 04101
(207) 517-8469

Rick Conant, PE
Manager
RLC Engineering
267 Whitten Road
Hallowell, ME 04347
(207) 621-1077 x101

Peter G. Vigue
Chairman & CEO
The Cianbro Companies
101 Cianbro Square
Pittsfield, ME 04967
(207) 679-2192

Jared S. Des Rosiers
Partner
Energy Pierce Atwood LLP
254 Commercial Street
Portland, ME 04101
(207) 791-1390

Bankers – To be Determined

Completed Financial Data Sheets

Iberdrola USA's Financial Data Sheets for fiscal years:

- December 31, 2010 and 2009
- December 31, 2011 and 2010
- December 31, 2012 and 2011

are attached to this section in the following pages.

ATTACHMENT 5

New York Power Authority

REQUEST FOR PROPOSALS
CONTINGENCY PROCUREMENT OF
GENERATION AND TRANSMISSION

PLEASE COMPLETE FINANCIAL PRO FORMA DATASHEET IF PROPOSING A TRANSMISSION PROJECT

Shaded Cells are Input Cells. Complete all cells as applicable. If Not Applicable, indicate "N/A."

	Construction Period -- By Year			
Capital Costs ($000)	**2013**	**2014**	**2015**	**2016**
Construction Costs - (Indicate fixed and variable components)				
HVDC Cable	153,714	0	0	65,878
Convertor Stations	58,875	196,250	78,500	58,875
AC Construction	3,150	10,500	4,200	3,150
Total Capital Costs	215,739	206,750	82,700	127,903
Financing Costs				
Total Financing Costs	17,256	16,544	6,616	10,232
Total Financing Costs	17,256	16,544	6,616	10,232
Total Project Costs	232,995	223,294	89,316	138,135
Sources of Funds				
Financing				
Equity	116,498	111,647	44,658	69,067
Debt	116,498	111,647	44,658	69,067
Other Sources				
Total	232,995	223,294	89,316	138,135

Pro-Forma Financial Template -- Initial Capital Structure

Construction Financing ($ '000's):	**% of Total**	**$000's**
Debt (list all debt)	50%	341,870
Equity	50%	341,870
Total Project Costs	100%	683,740

Permanent Financing ($ in thousands):	**% of Total**	**$000's**
Debt (list all debt)	50%	341,870
Equity	50%	341,870
Total Project Costs	100%	683,740

ATTACHMENT 5

New York Power Authority

REQUEST FOR PROPOSALS --- CONTINGENCY PROCUREMENT OF GENERATION AND TRANSMISSION

PLEASE COMPLETE FINANCIAL PRO FORMA DATASHEET IF PROPOSING A TRANSMISSION PROJECT--ADD/SUBTRACT YEARS TO CORRESPOND TO PROPOSED TERM

Shaded Cells are Input Cells. Complete all cells as applicable. If Not Applicable, indicate "N/A."

Year*	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Transmission Assumptions	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Cable Line Capacity (MW)				1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Major Scheduled Outages (Hours)					80		80		80		80		80		80		80		80		80		80		80		80		80
Income Statement, ($ '000's)																													
Revenues																													
Total Estimated Revenue	**13,518**	**39,995**	**58,138**	**101,844**	**120,465**	**118,124**	**115,918**	**113,844**	**111,886**	**110,034**	**108,289**	**106,456**	**104,613**	**102,784**	**100,968**	**99,167**	**97,381**	**95,609**	**93,853**	**92,112**	**90,380**	**88,674**	**86,975**	**86,777**	**87,212**	**86,809**	**86,423**	**86,056**	**85,707**
O&M Expenses																													
Operating and Maintenance Costs	0	0	0	10,128	10,331	10,537	10,748	10,963	11,182	11,406	11,634	11,867	12,104	12,346	12,593	12,845	13,102	13,364	13,631	13,904	14,182	14,465	14,755	15,050	15,351	15,658	15,971	16,290	16,616
Total O&M	0	0	0	10,128	10,331	10,537	10,748	10,963	11,182	11,406	11,634	11,867	12,104	12,346	12,593	12,845	13,102	13,364	13,631	13,904	14,182	14,465	14,755	15,050	15,351	15,658	15,971	16,290	16,616
General & Administration (G&A) Expenses																													
A&G	0	0	0	8,862	9,039	9,220	9,404	9,593	9,784	9,980	10,180	10,383	10,591	10,803	11,019	11,239	11,464	11,693	11,927	12,166	12,409	12,657	12,910	13,168	13,432	13,700	13,974	14,254	14,539
Property taxes and land use	0	0	0	5,128	10,461	10,671	10,884	11,102	11,324	11,550	11,781	12,017	12,257	12,502	12,752	13,007	13,268	13,533	13,804	14,080	14,361	14,648	14,941	15,240	15,545	15,856	16,173	16,496	16,826
Total G&A	0	0	0	13,990	19,501	19,891	20,288	20,694	21,108	21,530	21,961	22,400	22,848	23,305	23,771	24,247	24,731	25,226	25,731	26,245	26,770	27,306	27,852	28,409	28,977	29,556	30,148	30,750	31,365
Total Operating Expenses	0	0	0	24,118	29,831	30,428	31,036	31,657	32,290	32,936	33,595	34,267	34,952	35,651	36,364	37,091	37,833	38,590	39,362	40,149	40,952	41,771	42,606	43,458	44,328	45,214	46,118	47,041	47,982
Operating Income	13,518	39,995	58,138	77,725	90,634	87,696	84,882	82,187	79,596	77,098	74,695	72,189	69,661	67,133	64,604	62,076	59,548	57,019	54,491	51,963	49,428	46,903	44,368	43,319	42,884	41,595	40,305	39,015	37,725
Depreciation & Amortization Expense	0	0	0	8,547	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094
Interest Expense	2,912	8,616	12,524	15,185	16,376	15,682	15,020	14,386	13,780	13,198	12,638	12,092	11,547	11,003	10,458	9,913	9,369	8,824	8,280	7,735	7,190	6,645	6,100	5,622	5,278	5,000	4,722	4,444	4,167
Income taxes	4,201	12,431	18,070	20,601	21,156	20,438	19,743	19,075	18,424	17,788	17,175	16,417	15,632	14,846	14,060	13,274	12,488	11,702	10,917	10,131	9,339	8,558	7,767	8,247	8,915	8,514	8,113	7,712	7,312
Net Income	6,404	18,949	27,544	33,393	36,008	34,483	33,026	31,632	30,298	29,018	27,788	26,586	25,388	24,191	22,993	21,795	20,597	19,399	18,201	17,003	15,805	14,606	13,408	12,356	11,598	10,987	10,376	9,765	9,154
EBITDA	13,518	39,995	58,138	77,725	90,634	87,696	84,882	82,187	79,596	77,098	74,695	72,189	69,661	67,133	64,604	62,076	59,548	57,019	54,491	51,963	49,428	46,903	44,368	43,319	42,884	41,595	40,305	39,015	37,725
Cash Flow Statement																													
Net Income	6,404	18,949	27,544	33,393	36,008	34,483	33,026	31,632	30,298	29,018	27,788	26,586	25,388	24,191	22,993	21,795	20,597	19,399	18,201	17,003	15,805	14,606	13,408	12,356	11,598	10,987	10,376	9,765	9,154
Working Capital																													
Accounts Payable																													
Accounts Receivable																													
Deferred Taxes	0	0	0	5,983	11,296	10,003	8,807	7,682	6,653	5,720	4,834	4,691	4,691	4,691	4,691	4,691	4,691	4,691	4,691	4,691	4,714	4,691	4,714	-646	-5,983	-5,983	-5,983	-5,983	-5,983
Depreciation & Amortization Expense	0	0	0	8,547	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094
Capital Expenditures	-215,700	-206,800	-82,700	-127,900																									
Financing																													
Debt Service																													
Equity																													
Net Cash Flow	-215,700	-206,800	-82,700	-113,370	28,389	27,097	25,900	24,776	23,747	22,813	21,928	21,784	21,784	21,784	21,784	21,784	21,784	21,784	21,784	21,784	21,808	21,784	21,808	16,448	11,111	11,111	11,111	11,111	11,111
Balance Sheet Statement																													
Working Capital																													
Accounts Receivable																													
Gross Plant	232,956	456,300	545,616	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748
Accumulated Depreciation	0	0	0	8,547	25,641	42,734	59,828	76,922	94,015	111,109	128,203	145,296	162,390	179,484	196,578	213,671	230,765	247,859	264,952	282,046	299,140	316,233	333,327	350,421	367,515	384,608	401,702	418,796	435,889
Net Plant	232,956	456,300	545,616	675,201	658,107	641,014	623,920	606,826	589,733	572,639	555,545	538,452	521,358	504,264	487,170	470,077	452,983	435,889	418,796	401,702	384,608	367,515	350,421	333,327	316,233	299,140	282,046	264,952	247,859
Total Assets	232,956	456,300	545,616	675,201	658,107	641,014	623,920	606,826	589,733	572,639	555,545	538,452	521,358	504,264	487,170	470,077	452,983	435,889	418,796	401,702	384,608	367,515	350,421	333,327	316,233	299,140	282,046	264,952	247,859
Current Liabilities																													
Deferred Taxes	0	0	0	5,983	17,278	27,282	36,088	43,770	50,423	56,143	60,977	65,667	70,358	75,048	79,739	84,429	89,120	93,810	98,501	103,191	107,906	112,596	117,311	116,665	110,682	104,699	98,716	92,733	86,751
Capitalization																													
Debt	116,478	228,150	272,808	334,609	320,415	306,866	293,916	281,528	269,655	258,248	247,284	236,392	225,500	214,608	203,716	192,824	181,932	171,040	160,147	149,255	138,351	127,459	116,555	108,331	102,776	97,220	91,665	86,110	80,554
Equity	116,478	228,150	272,808	334,609	320,415	306,866	293,916	281,528	269,655	258,248	247,284	236,392	225,500	214,608	203,716	192,824	181,932	171,040	160,147	149,255	138,351	127,459	116,555	108,331	102,776	97,220	91,665	86,110	80,554
Total Liabilities & Capitalization	232,956	456,300	545,616	675,201	658,107	641,014	623,920	606,826	589,733	572,639	555,545	538,452	521,358	504,264	487,170	470,077	452,983	435,889	418,796	401,702	384,608	367,515	350,421	333,327	316,233	299,140	282,046	264,952	247,859

***Adjust number of column years needed to match contract term. If term is greater/less than shown, add/delete columns to match contract term.**

ATTACHMENT 5

30	31	32	33	34	35	36	37	38	39	40	**Year***
2042	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**Transmission Assumptions**
1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	Cable Line Capacity (MW)
	80		80		80		80		80		Major Scheduled Outages (Hours)
											Income Statement, ($ '000's)
											Revenues
85,377	**85,066**	**84,775**	**84,503**	**84,252**	**84,022**	**83,813**	**83,626**	**83,460**	**83,318**	**83,198**	**Total Estimated Revenue**
											O&M Expenses
16,948	17,287	17,633	17,986	18,345	18,712	19,087	19,468	19,858	20,255	20,660	Operating and Maintenance Costs
16,948	17,287	17,633	17,986	18,345	18,712	19,087	19,468	19,858	20,255	20,660	**Total O&M**
											General & Administration (G&A) Expenses
14,830	15,126	15,429	15,738	16,052	16,373	16,701	17,035	17,376	17,723	18,077	A&G
17,163	17,506	17,856	18,213	18,578	18,949	19,328	19,715	20,109	20,511	20,922	Property taxes and land use
31,993	32,633	33,285	33,951	34,630	35,323	36,029	36,750	37,485	38,234	38,999	**Total G&A**
48,941	49,920	50,918	51,937	52,975	54,035	55,116	56,218	57,342	58,489	59,659	**Total Operating Expenses**
36,436	35,146	33,856	32,567	31,277	29,987	28,698	27,408	26,118	24,828	23,539	**Operating Income**
17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	**Depreciation & Amortization Expense**
3,889	3,611	3,333	3,055	2,778	2,500	2,222	1,944	1,667	1,389	1,111	**Interest Expense**
6,911	6,510	6,109	5,708	5,307	4,906	4,505	4,105	3,704	3,303	2,902	**Income taxes**
8,543	7,932	7,320	6,709	6,098	5,487	4,876	4,265	3,654	3,043	2,432	**Net Income**
36,436	35,146	33,856	32,567	31,277	29,987	28,698	27,408	26,118	24,828	23,539	**EBITDA**
											Cash Flow Statement
8,543	7,932	7,320	6,709	6,098	5,487	4,876	4,265	3,654	3,043	2,432	Net Income
											Working Capital
											Accounts Payable
											Accounts Receivable
-5,983	-5,983	-5,983	-5,983	-5,983	-5,983	-5,983	-5,983	-5,983	-5,983	-5,983	**Deferred Taxes**
17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	17,094	**Depreciation & Amortization Expense**
											Capital Expenditures
											Financing
											Debt Service
											Equity
11,111	11,111	11,111	11,111	11,111	11,111	11,111	11,111	11,111	11,111	11,111	**Net Cash Flow**
											Balance Sheet Statement
											Working Capital
											Accounts Receivable
683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	683,748	**Gross Plant**
452,983	470,077	487,170	504,264	521,358	538,452	555,545	572,639	589,733	606,826	623,920	**Accumulated Depreciation**
230,765	213,671	196,578	179,484	162,390	145,296	128,203	111,109	94,015	76,922	59,828	**Net Plant**
230,765	213,671	196,578	179,484	162,390	145,296	128,203	111,109	94,015	76,922	59,828	**Total Assets**
											Current Liabilities
80,768	74,785	68,802	62,819	56,837	50,854	44,871	38,888	32,905	26,923	20,940	Deferred Taxes
											Capitalization
74,999	69,443	63,888	58,332	52,777	47,221	41,666	36,110	30,555	25,000	19,444	Debt
74,999	69,443	63,888	58,332	52,777	47,221	41,666	36,110	30,555	25,000	19,444	Equity
230,765	213,671	196,578	179,484	162,390	145,296	128,203	111,109	94,015	76,922	59,828	**Total Liabilities & Capitalization**

ATTACHMENT 7

New York Power Authority

REQUEST FOR PROPOSALS CONTINGENCY PROCUREMENT OF GENERATION AND TRANSMISSION

PLEASE COMPLETE DATASHEET IF PROPOSING A TRANSMISSION FACILITY

Shaded Cells are Input Cells

PROPOSAL ID (Use Same ID as Facility proposed in Combination)	**Q13-5441LW**
Date Submitted	**5/20/2013**
Project Name	**Connect New York**
Transmission Capability (MW)	**1000**

Project Pricing Components

Term (Years)	**40**
Project COD Date	**Jun-16**
Pricing Valid Through	**December 31, 2013**
Project Pricing Terms (Indicate $/Month cost or other pricing terms)	**Traditional Cost of service ratemaking**
Indicate if Project Pricing is Fixed or Escalated -	**Based on actual costs**
If Escalated, the following terms apply:	**NA**
Escalation Index	**Implicit Price Deflators for Gross Domestic Product**
Base Year	**COD Date**
Frequency of Escalation	**Annual**
Property rights and/or revenue sources (e.g. TCCs) assigned to NYPA	**None**

Project Pricing Component Projection

Contract Year*	Monthly Project Price ($/Month)	Total Annual Cost ($)
1	1,126,472	13,517,667
2	3,332,937	39,995,249
3	4,844,823	58,137,876
4	8,486,966	101,843,590
5	10,038,753	120,465,035
6	9,843,662	118,123,945
7	9,659,859	115,918,308
8	9,486,989	113,843,864
9	9,323,826	111,885,912
10	9,169,466	110,033,592
11	9,024,106	108,289,273
12	8,871,324	106,455,883
13	8,717,743	104,612,913
14	8,565,304	102,783,647
15	8,414,030	100,968,358
16	8,263,944	99,167,325
17	8,115,070	97,380,835
18	7,967,431	95,609,178
19	7,821,054	93,852,650
20	7,675,963	92,111,554
21	7,531,632	90,379,585
22	7,389,510	88,674,121
23	7,247,882	86,974,585
24	7,231,408	86,776,897
25	7,267,646	87,211,747
26	7,234,052	86,808,619
27	7,201,935	86,423,218
28	7,171,325	86,055,897
29	7,142,252	85,707,020
30	7,114,746	85,376,953
31	7,088,840	85,066,075
32	7,064,564	84,774,769
33	7,041,952	84,503,425
34	7,021,037	84,252,444
35	7,001,853	84,022,232
36	6,984,434	83,813,205
37	6,968,816	83,625,787
38	6,955,034	83,460,409
39	6,943,126	83,317,514
40	6,933,129	83,197,549

***Adjust number of rows to match proposed term in years.**

List of Assumptions: Pro forma Cost and Pricing Component Projection

Category	Description of Assumptions Used
Monthly Project Price	40 year life, 50/50 Cap structure, 11% ROE, 5% Cost of Debt, AFUDC

Iberdrola USA, Inc.
Consolidated Financial Statements
For the Years Ended December 31, 2010 and 2009

Iberdrola USA, Inc.

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Management’s Report on Internal Control Over Financial Reporting

Iberdrola USA, Inc.’s (the company) internal control over financial reporting is a process affected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. An entity’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 entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and those charged with governance; and (3) provide reasonable assurance regarding prevention, or timely detection and correction of unauthorized acquisition, use, or disposition of the entity’s assets that could have a material effect on the financial statements.

Management is responsible for establishing and maintaining effective internal control over financial reporting. Management assessed the effectiveness of the company’s internal control over financial reporting as of December 31, 2010, based on the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework*. Based on that assessment, management concluded that, as of December 31, 2010, the company’s internal control over financial reporting is effective based on the criteria established in *Internal Control—Integrated Framework*. The effectiveness of the company’s internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent public accounting firm, as stated in their report which appears herein.

Iberdrola USA, Inc.
February 17, 2011

Report of Independent Auditors

To the Stockholder and Board of Directors of Iberdrola USA, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income, of cash flows and of changes in equity present fairly, in all material respects, the financial position of Iberdrola USA, Inc. and its subsidiaries (collectively, the "Company") at December 31, 2010 and 2009, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assertion of the effectiveness of internal control over financial reporting, included in *Management's Report on Internal Control Over Financial Reporting* dated February 17, 2011, listed in the accompanying Index to the Iberdrola USA, Inc. Consolidated Financial Statements for the Years Ended December 31, 2010 and 2009. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits of the financial statements in accordance with auditing standards generally accepted in the United States of America and our audit of internal control over financial reporting in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 to the consolidated financial statements, the Company sold three of their natural gas holding company subsidiaries and their natural gas distribution utilities on November 16, 2010.

A company's internal control over financial reporting is a process effected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting

PricewaterhouseCoopers LLP, Two Commerce Square, Suite 1700, 2001 Market Street, Philadelphia, PA 19103-7042
T: (267) 330 3000, F: (267) 330-3300, www.pwc.com/us

includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 those charged with governance; and (iii) provide reasonable assurance regarding prevention, or timely detection and correction of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent, or detect and correct 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.

PricewaterhouseCoopers LLP

February 17, 2011

Iberdrola USA, Inc.
Consolidated Statements of Operations

Year ended December 31,	2010	2009
(Thousands)		
Operating Revenues		
Utility	**$3,262,847**	$3,188,716
Other	**400,080**	424,554
Total Operating Revenues	**3,662,927**	3,613,270
Operating Expenses		
Electricity purchased and fuel used in generation		
Utility	**958,277**	983,495
Other	**277,867**	299,123
Natural gas purchased		
Utility	**351,207**	462,430
Other	**56,664**	64,308
Other operating expenses	**726,561**	821,770
Maintenance	**285,355**	198,981
Depreciation and amortization	**239,160**	236,424
Other taxes	**235,715**	215,714
Total Operating Expenses	**3,130,806**	3,282,245
Operating Income	**532,121**	331,025
Other (Income)	**(31,579)**	(28,194)
Other Deductions	**196,058**	4,576
Interest Charges, Net	**259,813**	273,264
Income From Continuing Operations Before Income Taxes	**107,829**	81,379
Income Taxes (Benefits)	**(24,124)**	(7,107)
Income From Continuing Operations	**131,953**	88,486
Discontinued Operations		
(Loss) income from discontinued operations (including loss on sale of natural gas companies of $364,046 in 2010)	**(296,716)**	27,249
Income taxes (including taxes on sale of $18,300 in 2010)	**42,181**	3,115
(Loss) Income From Discontinued Operations	**(338,897)**	24,134
Net (Loss) Income	**(206,944)**	112,620
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	**785**	1,068
Net Income Attributable to Other Noncontrolling Interests	**1,615**	1,624
Net (Loss) Income Attributable to Iberdrola USA	**$(209,344)**	$109,928

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

Iberdrola USA, Inc.
Consolidated Statements of Comprehensive Income

Year ended December 31,	2010	2009
(Thousands)		
Net (Loss) Income	**$(206,944)**	$112,620
Other Comprehensive Income, Net of Tax	**11,522**	43,624
Comprehensive (Loss) Income	**(195,422)**	156,244
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	**785**	1,068
Comprehensive Income Attributable to Other Noncontrolling Interests	**1,615**	1,624
Comprehensive (Loss) Income Attributable to Iberdrola USA	**$(197,822)**	$153,552

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

Iberdrola USA, Inc.
Consolidated Balance Sheets

December 31,	2010	2009
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$75,688**	$113,504
Accounts receivable and unbilled revenues, net	**641,779**	775,274
Fuel and natural gas in storage, at average cost	**80,515**	226,768
Materials and supplies, at average cost	**31,483**	30,147
Deferred income taxes	**62,081**	37,500
Derivative assets	**9,924**	5,145
Prepaid income taxes	**168,600**	129,223
Broker margin accounts	**22,076**	15,383
Prepayments and other current assets	**97,970**	123,236
Total Current Assets	**1,190,116**	1,456,180
Utility Plant, at Original Cost		
Electric	**6,419,555**	6,201,951
Natural gas	**1,423,381**	2,782,685
Common	**539,260**	607,776
	8,382,196	9,592,412
Less accumulated depreciation	**3,029,712**	3,318,424
Net Utility Plant in Service	**5,352,484**	6,273,988
Construction work in progress	**496,319**	188,540
Total Utility Plant	**5,848,803**	6,462,528
Assets Held For Sale	**32,730**	33,455
Other Property and Investments		
Other property and investments	**150,702**	217,806
Tax equity investments	**478,016**	304,821
Total Other Property and Investments	**628,718**	522,627
Regulatory and Other Assets		
Regulatory assets		
Nuclear plant obligations	**75,896**	109,896
Unfunded future income taxes	**453,145**	481,525
Environmental remediation costs	**237,026**	269,230
Unamortized loss on debt reacquisitions	**44,667**	49,150
Nonutility generator termination agreements	**35,286**	45,355
Natural gas hedges	**12,802**	9,652
Pension and other postretirement benefits	**886,224**	1,031,962
Other	**291,181**	427,595
Total regulatory assets	**2,036,227**	2,424,365
Other assets		
Goodwill	**983,646**	1,526,580
Prepaid pension benefits	**87,336**	145,723
Derivative assets	**418**	442
Other	**66,082**	101,302
Total other assets	**1,137,482**	1,774,047
Total Regulatory and Other Assets	**3,173,709**	4,198,412
Total Assets	**$10,874,076**	$12,673,202

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

Iberdrola USA, Inc.
Consolidated Balance Sheets

December 31,	2010	2009
(Thousands, except shares)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	**$89,055**	$233,502
Notes payable	**142,400**	118,950
Accounts payable and accrued liabilities	**265,445**	195,697
Accounts payable, electricity purchased	**108,560**	91,975
Accounts payable, natural gas purchased	**99,341**	90,672
Interest accrued	**26,003**	36,515
Interest accrued on debt to affiliates	**7,503**	19,116
Taxes accrued	**195,244**	74,095
Derivative liabilities	**13,351**	9,608
Environmental remediation costs	**49,044**	40,028
Other	**225,066**	246,944
Total Current Liabilities	**1,221,012**	1,157,102
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligations	**728,407**	931,964
Deferred income taxes	**368,564**	367,764
Gain on sale of generation assets	**47,196**	22,860
Pension benefits	**22,845**	71,141
Positive benefit adjustments	**200,339**	297,938
Other	**167,599**	198,236
Total regulatory liabilities	**1,534,950**	1,889,903
Other liabilities		
Deferred income taxes	**1,218,120**	1,153,694
Nuclear plant obligations	**143,104**	150,279
Pension and other postretirement benefits	**457,711**	603,309
Environmental remediation costs	**158,717**	177,322
Derivative liabilities	**427**	493
Other	**185,587**	215,563
Total other liabilities	**2,163,666**	2,300,660
Total Regulatory and Other Liabilities	**3,698,616**	4,190,563
Long-term Debt		
Other long-term debt	**2,139,334**	2,598,933
Long-term debt owed to affiliates	**650,000**	1,350,000
Total Long-term Debt	**2,789,334**	3,948,933
Total Liabilities	**7,708,962**	9,296,598
Commitments and Contingencies		
Preferred Stock of Subsidiaries		
Redeemable preferred stock, noncontrolling interests	**12,464**	24,545
Iberdrola USA Common Stock Equity		
Common stock ($.01 par value, 100 shares authorized and outstanding at December 31, 2010 and 2009)	**-**	-
Capital in excess of par value	**2,009,101**	2,009,101
Retained earnings	**1,215,017**	1,424,361
Accumulated other comprehensive loss	**(85,204)**	(96,726)
Total Iberdrola USA Common Stock Equity	**3,138,914**	3,336,736
Other Noncontrolling Interests	**13,736**	15,323
Total Equity	**3,152,650**	3,352,059
Total Liabilities and Equity	**$10,874,076**	$12,673,202

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

Iberdrola USA, Inc.
Consolidated Statements of Cash Flows

Year Ended December 31,	2010	2009
(Thousands)		
Operating Activities		
Net (loss) income	**$(206,944)**	$112,620
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**283,962**	281,562
Amortization of regulatory and other assets and liabilities	**104,106**	68,917
Loss on sale of natural gas companies	**88,243**	-
Deferred income taxes and investment tax credits, net	**(9,649)**	147,878
Bridgeport pipeline contract impairment	**-**	7,312
Goodwill Impairment	**275,802**	-
Pension income (expense)	**67,857**	(4,962)
Positive benefit adjustments including carrying costs	**(97,599)**	17,928
Changes in current operating assets and liabilities		
Accounts receivable and unbilled revenues, net	**37,717**	141,627
Broker margin accounts	**(6,693)**	70,398
Environmental remediation costs	**9,757**	(26,269)
Inventory	**10,898**	141,778
Prepayments and other current assets	**(126,190)**	(36,193)
Accounts payable and accrued liabilities	**85,144**	(119,097)
Interest accrued on debt to affiliates	**(11,613)**	19,116
Interest accrued	**(5,026)**	(19,831)
Taxes accrued	**215,568**	(240)
Other current liabilities	**4,919**	41,199
Pension and other postretirement benefits contributions	**(33,430)**	(12,615)
Changes in other assets	**10,428**	(143,182)
Changes in other liabilities	**(1,556)**	(4,051)
Net Cash Provided by Operating Activities	**695,701**	683,895
Investing Activities		
Utility plant additions	**(592,842)**	(324,022)
Grants received from governmental entities	**24,768**	-
Proceeds from sale of Capitol Area System	**-**	10,624
Proceeds from sale of natural gas companies	**917,929**	-
Other property additions	**(559)**	(1,012)
Other property sold	**7,276**	1,440
Notes receivable from affiliate	**(550,000)**	-
Repayment of notes receivable from affiliate	**550,000**	-
Tax equity investments	**(236,000)**	(304,821)
Investments available for sale	**54,434**	18,957
Net Cash Provided by (Used in) Investing Activities	**175,006**	(598,834)
Financing Activities		
Equity contribution from parent	**-**	250,000
Repayment of preferred stock of subsidiaries, including net premiums	**(11,253)**	(4)
Derivative activity	**-**	(23,631)
Long-term note issuances, debt owed to affiliates	**-**	1,350,000
Long-term note repayments, debt owed to affiliates	**(700,000)**	-
Long-term note issuances	**-**	354,800
Long-term note repayments	**(222,991)**	(1,467,633)
Notes payable three months or less, net	**28,094**	(505,038)
Dividends to other noncontrolling interests	**(1,588)**	(875)
Dividends paid on preferred stock of subsidiaries, noncontrolling interests	**(785)**	(1,068)
Net Cash Used in Financing Activities	**(908,523)**	(43,449)
Net (Decrease) Increase in Cash and Cash Equivalents	**(37,816)**	41,612
Cash and Cash Equivalents, Beginning of Year	**113,504**	71,892
Cash and Cash Equivalents, End of Year	**$75,688**	$113,504

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

Iberdrola USA, Inc.
Consolidated Statements of Changes in Equity

(Thousands, except per share amounts)	Iberdrola USA Shareholder: Common Stock Outstanding $.01 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Other Noncontrolling Interests	Comprehensive Income (Loss)*	Total
Balance, January 1, 2009	-	-	$1,759,101	$1,314,433	$(140,350)	$14,574		$2,947,758
Net income*				109,928		1,624	$111,552	111,552
Other comprehensive income, net of tax					43,624		43,624	43,624
Comprehensive income*							$155,176	155,176
Equity contribution from parent			250,000					250,000
Dividends to other noncontrolling interests						(875)		(875)
Balance, December 31, 2009	-	-	2,009,101	1,424,361	(96,726)	15,323		3,352,059
Net income (loss)*				(209,344)		1,615	$(207,729)	(207,729)
Other comprehensive income, net of tax					11,522		11,522	11,522
Comprehensive income*							$(196,207)	(196,207)
Dividends to other noncontrolling interests						(3,202)		(3,202)
Balance, December 31, 2010	-	-	$2,009,101	$1,215,017	$(85,204)	$13,736		$3,152,650

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

*Amounts do not include Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests of $1,068 for 2009 and $785 for 2010.

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background: Iberdrola USA, Inc. (Iberdrola USA, the company, we, our, us) is a public utility holding company operating under the Public Utility Holding Company Act of 2005. Iberdrola USA is a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain. On December 1, 2009, we changed our legal and operating name to Iberdrola USA, Inc., from Energy East Corporation. We are a super-regional energy services and delivery company with operations in New York, Maine, Connecticut and New Hampshire. Our wholly-owned subsidiaries, and their principal operating utilities, include: CMP Group, Inc. – Central Maine Power Company (CMP), and RGS Energy Group, Inc. – New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E).

On November 16, 2010, after receiving all regulatory approvals, we sold three of our natural gas holding company subsidiaries and their natural gas distribution utilities to UIL Holdings Corporation (UIL). The three holding companies and their related natural gas distribution utilities are: CTG Resources, Inc. (CTG) and Connecticut Natural Gas Corporation (CNG); Connecticut Energy Corporation (CEC) and The Southern Connecticut Gas Company (SCG); and Berkshire Energy Resources (BER) and The Berkshire Gas Company (BGC). (See Note 2.)

We have evaluated events or transactions that occurred after December 31, 2010, for inclusion in these financial statements through February 17, 2011, which is the date these financial statements were available to be issued.

As part of an effort to reduce costs and increase efficiency, we undertook various measures to reduce workforce levels in 2010. We reduced workforce levels by 140 through an involuntary separation at a cost of approximately $3 million, which we paid in cash and charged to other operating expenses. We also offered voluntary early retirement programs (VERPs) to qualifying nonunion and union employees. The 525 employees who accepted the VERPs will receive forms of enhanced pension benefits. In addition, we offered a voluntary severance program (VSP) to certain employees, resulting in a reduction of 36 employees. In 2010 we recorded costs totaling approximately $38 million for the VERPs, which will be paid from our companies' pension plans, and approximately $1 million for the VSP. As part of the New York rate order (see Note 15), we were allowed to recover and defer $32 million of these costs in rates.

***Accounts receivable*:** Accounts receivable at December 31 include unbilled revenues of $167 million for 2010 and $209 million for 2009, and are shown net of an allowance for doubtful accounts at December 31 of $40 million for 2010 and $42 million for 2009. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $37 million in 2010 and $42 million in 2009.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and delivery loss factors. Changes in those assumptions could significantly affect the estimates of unbilled revenues.

The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience for each service region and operating segment. Each month the operating companies review their allowance for doubtful accounts and past due accounts over 90 days and/or above a specified amount, and review all other balances on a pooled basis by age and type of receivable. When an operating company believes that a receivable will not be recovered, it charges off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates. During 2010 we recorded an increase in the allowance for doubtful accounts of $7 million because we no longer consider customer security deposits when we determine the amount of our allowance for doubtful accounts.

***Asset retirement obligations*:** We record the fair value of the liability for an asset retirement obligation (ARO) and/or a conditional ARO in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability to its present value periodically over time, and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. Our regulated utilities defer any timing differences between rate recovery and depreciation expense as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

Our ARO at December 31, including our conditional ARO, was $34 million for 2010 and $51 million for 2009. The ARO primarily consists of obligations related to removal or retirement of: asbestos, PCB-contaminated equipment, gas pipeline and cast iron gas mains. The long-lived assets associated with our AROs are generation property, gas storage property, distribution property and other property.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2010 and 2009.

Year ended December 31,	**2010**	**2009**
(Thousands)		
ARO, beginning of year	**$50,953**	$50,788
Liabilities settled during the year	**(2,500)**	(2,309)
Accretion expense	**3,016**	2,140
Revisions in estimated cash flows	**(219)**	334
Disposition of liabilities related to sale of natural gas companies	**(17,572)**	-
ARO, end of year	**$33,678**	$50,953

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

Accrued removal obligations: Our regulated utilities meet the requirements concerning accounting for regulated operations, and recognize a regulatory liability, for financial reporting purposes only, for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Notes to Consolidated Financial Statements

***Consolidated statements of cash flows*:** We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and those investments are included in cash and cash equivalents.

Supplemental Disclosure of Cash Flows Information	**2010**	**2009**
(Thousands)		
Cash paid (received) during the year ended December 31:		
Interest, net of amounts capitalized	**$257,798**	$255,014
Income taxes, net of cash paid	**$(68,103)**	$(150,374)

Interest capitalized was $3 million in 2010 and $1 million in 2009. We have decreased utility plant additions by $87 million for amounts payable as of December 31, 2010.

***Preliminary survey costs*:** Consolidated preliminary survey costs included in Other assets at December 31 totaled approximately $11 million for 2010 and $16 million for 2009. Preliminary survey costs represent expenditures incurred for the purpose of determining the feasibility of utility projects under contemplation. When construction begins on such projects, the amounts are moved to Construction work in progress, and then eventually to Utility plant when construction is completed and the asset is placed in service. If a project is abandoned, the costs incurred for that project are charged to an appropriate expense account, and included in future rates.

***Depreciation and amortization*:** We determine depreciation expense substantially using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal, in service at each operating company. The weighted-average service lives of certain classifications of property are: transmission property - 56 years, distribution property - 54 years, generation property - 57 years, gas production property - 20 years, gas storage property - 23 years, and other property - 37 years. Our depreciation accruals were equivalent to 2.7% of average depreciable property for 2010 and 2.8% for 2009.

We charge repairs and minor replacements to operating expense, and capitalize renewals and betterments, including certain indirect costs. We charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation.

Bridgeport pipeline contract impairment: CNE Energy Services Group, Inc. (CNE Energy), was formerly a subsidiary of CEC; however, after the sale of natural gas companies in November 2010, it is now a subsidiary of The Energy Network, Inc. CNE Energy provided the funds for the construction of an 11.5 mile long pipeline in Bridgeport, Connecticut, which was subject to a 20 year gas transmission agreement (Agreement) with an unrelated entity. SCG constructed the pipeline and has owned and operated it since its completion. In addition to funding the pipeline construction costs, CNE Energy paid all operating and maintenance costs related to the pipeline project. In February 1998 the Connecticut Department of Public Utility Control (DPUC) issued a decision concerning the allocation of revenues during the first 10 years of the Agreement, allocating a portion to SCG for the benefit of its ratepayers with the remaining portion retained by CNE Energy.

The original DPUC decision required SCG to petition the DPUC by July 1, 2008, for an adjustment to the allocation of revenues for the second 10 years of the Agreement. The DPUC issued a decision on April 1, 2009, reducing the annual revenue allocation to CNE Energy for the remaining term of the Agreement. Based on its estimate of undiscounted cash flows for the remaining years, CNE Energy determined that the combined $7.1 million carrying amount of the contract interest and valuation adjustment was not recoverable, and impaired the entire net carrying amount. In addition, because substantially all of its economic activity is derived from the Bridgeport contract, CNE Energy also impaired $0.2 million of net goodwill in 2009. The combined pretax impairments totaling approximately $7.3 million are included in depreciation and amortization on the income statement. The total after-tax effect of the impairments is approximately $4.7 million.

***Goodwill*:** We are required to perform an annual goodwill impairment test at the same time each year and, accordingly, we perform our annual impairment testing of goodwill during the third quarter of each year. We update the test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. The analysis of a potential impairment of goodwill requires a two step process. Step one of the impairment test involves comparing the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of goodwill impairment loss. If the carrying amount is less than fair value, further testing for goodwill impairment is not performed.

Step two of the goodwill impairment test involves comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. In step two, determining the implied fair value of goodwill requires the valuation of a reporting unit's identifiable tangible and intangible assets and liabilities as if the reporting unit had been acquired in a business combination on the testing date. The difference between the fair value of the entire reporting unit as determined in step one and the net fair value of all identifiable assets and liabilities represents the implied fair value of goodwill. A goodwill impairment charge, if any, would be the difference between the carrying amount of goodwill and the implied fair value of goodwill upon the completion of step two.

In performing our annual goodwill impairment test, for purposes of the step one analysis, we base the determination of the fair value of our reporting units on the income approach, which estimates fair value based on discounted future cash flows. Based on the completion of step one of our annual impairment analysis, management determined that the fair value of each reporting unit was greater than its carrying value.

We may be required to recognize an impairment of goodwill in the future due to market conditions or other factors related to our performance. Those market events could include a decline in the forecasted results in our business plan, significant adverse rate case results, changes in capital investment budgets or changes in interest rates that could permanently impair the fair value of a reporting unit. Recognition of impairments of a significant portion of goodwill would negatively affect our reported results of operations and total capitalization, the effect of which could be material and could make it more difficult to maintain our credit ratings, secure financing on attractive terms, maintain compliance with debt covenants and meet expectations of our regulators.

As a result of our decision in May 2010 to sell the natural gas companies we updated our impairment test of the goodwill for SCG, CNG and BGC in accordance with the two step process described above. We determined that the carrying value of the combined companies exceeded the purchase price agreed to by UIL, resulting in a goodwill impairment of $275.8 million. (See Note 3.)

Government grants: Authoritative accounting principles generally accepted in the United States of America do not address accounting for government grants. For that reason, we account for government grants related to depreciable assets in accordance with the prescribed Federal Energy Regulatory Commission (FERC) accounting for contributions in aid of construction, that is, the grant amount is credited to the cost of the related property, plant and equipment. In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as compensation for expenses already incurred in profit or loss in the period in which it becomes receivable. (See Note 9.)

Notes to Consolidated Financial Statements

New accounting standards adopted: We have adopted new accounting standards issued by the Financial Accounting Standards Board (FASB) as explained below.

Fair value measurements: The FASB has issued a number of new standards related to fair value measurements. In April 2009 the FASB issued two new standards related to fair value measurements, which we began applying effective April 1, 2009:

- One of the new standards provides guidance for determining fair value when the volume and level of activity for an asset or liability have significantly decreased and for identifying transactions that are not orderly. It provides additional guidance to entities for estimating fair value in accordance with existing requirements when the volume and level of activity for an asset or a liability has significantly decreased. Even in those circumstances, and without considering the valuation technique(s) used, the intention of fair value measurement does not change. The new standard also provides guidance for identifying circumstances that indicate a transaction is not orderly. In addition, it amends the disclosures in connection with fair value measurements to require disclosure in interim and annual periods about the inputs and valuation techniques used to measure fair value as well as a discussion of any changes in them during the period; and to require disclosures concerning debt and equity securities according to major security types.

  As a result of the revised guidance and continued illiquidity in the auction rate securities market, we reassessed the fair value of our $3.85 million investment in auction rate securities. We have held the investment for over two years as a result of several failed auctions. In 2009 we reduced the carrying value of our investment to $2.7 million; the writedown of $1.1 million is included in Other Deductions on the income statement.

- The other new standard provides amended guidance concerning the recognition and presentation of other-than-temporary impairments. It amends the guidance in U.S. generally accepted accounting principles for other-than-temporary impairment of debt securities (but not equity securities) to make it more operational and to improve the financial statement presentation and disclosure of other-than-temporary impairments on debt and equity securities.

In August 2009 the FASB issued an accounting standards update to provide amended guidance concerning the fair value measurement of liabilities. The key provisions of the amendments include clarification about valuation techniques that are to be used in circumstances in which a quoted price in an active market for the identical liability is not available and that a reporting entity is not to include a separate input or adjustments to other inputs to reflect the existence of a restriction that prevents the transfer of a liability. The amended guidance is effective for an entity's first reporting period (including interim periods) beginning after issuance of the update. We initially began applying the guidance effective October 1, 2009.

In January 2010 the FASB issued amendments to improve disclosures about fair value measurements. New disclosures that are or will be required include: 1) details of transfers in and out of Level 1 and Level 2 of the fair value measurement hierarchy, and 2) gross presentation of roll forward activity within Level 3 – separate presentation of information about purchases, sales, issuances and settlements. Entities will also have to provide fair value measurement disclosures for each class of assets and liabilities, as well as disclosures about inputs and valuation techniques for both recurring and nonrecurring Level 2 and Level 3 fair value measurements. The amendments are effective for interim and annual reporting periods beginning after December 15, 2009, except that the disclosures about Level 3 roll forward activity are effective for fiscal years beginning after December 15, 2010, and interim periods within those fiscal years.

Notes to Consolidated Financial Statements

Except for the reduction in the carrying value of our investment in auction rate securities in 2009, our adoption of the new standards related to fair value measurements had no effect on our financial position, results of operation or cash flows. Our adoption of the amendments concerning Level 3 roll forward activity effective for fiscal years beginning on or after January 1, 2011, and interim periods within those fiscal years, will not affect our results of operation, financial position or cash flows.

Variable interest entities: In June 2009 the FASB issued amendments to its revised interpretation concerning consolidation of variable interest entities (VIEs). The amendments clarify, but do not significantly change, the criteria for determining whether an entity meets the definition of a VIE, and change existing consolidation guidance so that qualifying special purpose entities are no longer exempt from consolidation. The amendments require an enterprise to perform ongoing assessments as to whether an entity is a VIE and whether the enterprise is the primary beneficiary of a VIE. Previously such assessments were required only when specified events occurred. The amended standard will alter how an enterprise determines when an entity that is not sufficiently capitalized or not controlled through voting should be consolidated. An enterprise will also be required to perform a qualitative analysis to determine whether it should provide consolidated reporting of an entity based upon the entity's purpose and design and the enterprise's ability to direct the entity's actions. The amended standard also requires enhanced disclosures to provide more transparent information about an enterprise's involvement in a VIE, and any significant changes in its risk exposure due to that involvement. The amendments are effective at the start of a company's first fiscal year beginning after November 15, 2009, including interim periods. Our adoption of the amendments effective January 1, 2010, did not affect our results of operation, financial position or cash flows.

***Other (Income) and Other Deductions*:**

Year Ended December 31,	**2010**	**2009**
(Thousands)		
Interest and dividend income	**$(1,648)**	$(2,298)
Allowance for funds used during construction	**(4,705)**	(1,152)
Earnings from equity investments	**(4,344)**	(4,403)
Carrying costs on regulatory assets	**(19,385)**	(20,193)
Miscellaneous	**(1,497)**	(148)
Total other (income)	**$(31,579)**	$(28,194)
Early retirement of debt	**$128,128**	-
Losses on energy risk contracts	**-**	$443
Civic donations	**1,268**	1,175
Impairment of auction rate security investment	**-**	1,115
Losses from tax equity investments	**62,805**	579
Miscellaneous	**3,857**	1,264
Total other deductions	**$196,058**	$4,576

Early retirement of debt: Iberdrola USA paid premiums in connection with the early retirement of long-term debt owed to an affiliate, Scottish Power, Limited as follows: premium of $82 million for the repayment of $400 million in November 2010 and premium of $46 million for the repayment of $300 million in December 2010.

***Principles of consolidation*:** These financial statements consolidate our majority-owned subsidiaries after eliminating intercompany transactions.

***Reclassifications*:** Certain amounts have been reclassified in our consolidated financial statements to conform to the 2010 presentation. The reclassifications primarily affect the income statement in connection with the presentation of discontinued operations, and the presentation of certain notes that contain income statement information.

***Regulatory assets and regulatory liabilities*:** Our public utility subsidiaries currently meet the requirements concerning accounting for regulated operations for their electric and natural gas operations in New York and Maine; however, we cannot predict what effect the competitive market or future actions of regulatory entities would have on their ability to continue to do so. If our public utility subsidiaries were to no longer meet the requirements concerning accounting for regulated operations for all or a separable part of their operations, they may have to record certain regulatory assets and regulatory liabilities as an expense or as revenue, or include them in accumulated other comprehensive income.

Pursuant to the requirements concerning accounting for regulated operations our utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. Substantially all regulatory assets for which funds have been expended are either included in rate base or are accruing carrying costs. As a result of the New York rate decision (see Note 15), the majority of regulatory assets and liabilities for NYSEG and RG&E are now included in rate base. As a result, carrying costs will decline significantly from 2010 levels. Our operating utilities also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs.

Unfunded future income taxes and deferred income taxes are amortized as the related temporary differences reverse. Unamortized loss on debt reacquisitions is amortized over the lives of the related debt issues. Nuclear plant obligations, demand side management program costs, gain on sale of generation assets, other regulatory assets and other regulatory liabilities are amortized over various periods in accordance with each operating utility's current rate plans. Amortization of total regulatory assets net of amortization of total regulatory liabilities was $74 million in 2010 and $51 million in 2009.

In 2009 we recorded reserves totaling $48.2 million on existing regulatory assets to reflect management's assessment of risk and increased uncertainty about the ultimate recovery for certain issues that had not been resolved with our regulators. Those amounts included $30 million for NYSEG and $10 million for RG&E related to disputes about earnings sharing accruals (see Note 9) and $5.5 million for CMP related to deferred storm costs. The resulting charge increased other operating expenses for the period.

Other regulatory assets and other regulatory liabilities consisted of:

December 31,	2010	2009
(Thousands)		
Other postretirement benefits	**$12,428**	$31,320
Customer Hardship Arrearage Forgiveness and related programs	**434**	47,550
Loss on sale of RG&E Oswego generating unit	**16,335**	22,467
Asset retirement obligation	**28,455**	25,986
Deferred storm costs	**54,479**	103,744
Deferred pension costs	**47,913**	44,600
Stranded cost reconciliation	**520**	8,501
Deferred natural gas costs	**1,077**	40,356
Nonbypassable wires charge	**4,004**	19,324
Incremental assessment	**11,261**	20,681
Cost to achieve efficiency initiatives	**29,966**	-
Other	**84,309**	63,066
Total other regulatory assets	**$291,181**	$427,595
Deferred natural gas costs	**$8,839**	$22,643
Asset retirement obligation	**4,419**	12,246
Nonfirm margin sharing	**-**	12,478
Economic development	**35,951**	21,657
Pension	**13,435**	27,237
Nuclear decommissioning	**12,545**	17,320
Tennessee gas pipeline settlement	**2,285**	10,408
Nonbypassable wires charge	**20,033**	-
Other	**70,092**	74,247
Total other regulatory liabilities	**$167,599**	$198,236

Related party transactions: We have a depository agreement with Scottish Power, Limited (Scottish Power) under which, in November 2010, we deposited $550 million for investment on our behalf by Scottish Power. In December 2010 we redeemed those funds. We earned $128 thousand on the investment. There was no amount outstanding under the depository agreement at December 31, 2010.

See Note 5 concerning amounts we owe to Scottish Power under a debt agreement. Interest expense on the debt for the year ended December 31 was $90 million for 2010 and $66 million for 2009.

See Note 8 concerning our related party transactions with respect to tax equity investments.

***Revenue recognition*:** We recognize revenues upon delivery of energy and energy-related products and services to our customers.

Pursuant to a Maine state law, CMP is prohibited from selling power to its retail customers. CMP does not enter into purchase or sales arrangements for power with ISO New England Inc., the New England Power Pool, or any other independent system operator or similar entity. CMP sells all of its power entitlements under its nonutility generator (NUG) and other purchase power contracts to unrelated third parties under bilateral contracts.

NYSEG and RG&E enter into power purchase and sales transactions with the New York Independent System Operator (NYISO). When NYSEG and RG&E sell electricity from owned generation to the NYISO, and subsequently repurchase electricity from the NYISO to serve their customers, they record the transactions on a net basis in their statements of income. NYSEG and RG&E net their purchase and sale transactions with the NYISO on an hourly basis.

In addition, our regulated utilities accrue revenue pursuant to the various regulatory provisions to record regulatory assets for revenues that will be collected in the future.

Taxes**:** We file a consolidated federal income tax return and allocate income taxes among Iberdrola USA and its subsidiaries in proportion to their contribution to consolidated taxable income. The determination and allocation of our income tax provision and its components are outlined and agreed to in the tax sharing agreements among Iberdrola USA and its subsidiaries.

Deferred income taxes reflect the effect of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and the amount recognized for tax purposes. We amortize investment tax credits over the estimated lives of the related assets.

We account for sales tax collected from customers and remitted to taxing authorities on a net basis.

We classify all interest and penalties related to uncertain tax positions as income tax expense.

Use of estimates and assumptions: The preparation of our consolidated financial statements in conformity with generally accepted accounting principles requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for doubtful accounts and unbilled revenues; (2) asset impairments, including goodwill; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; and (8) earnings sharing mechanism (ESM), nonbypassable wires charges and environmental remediation liability. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside experts to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Note 2. Sale of Natural Gas Companies

On November 16, 2010, we sold three of our natural gas holding company subsidiaries and their natural gas distribution utilities to UIL at an after-tax loss of $382 million, including impairments of goodwill totaling $275.8 million. The three holding companies and related natural gas distribution utilities are: CTG and CNG, CEC and SCG, and BER and BGC. Pursuant to the purchase agreement we retained our nonutility subsidiaries CNE Energy Services Group, Inc. and TEN Companies, Inc. (TEN Cos.) at the time of the transaction.

The transaction was valued at $1,296 million, including the assumption of approximately $386 million of debt. We received approximately $918 million in cash at closing, which reflects closing adjustments of $8 million primarily for estimated cash balances and changes in net working capital. The agreement provides for an adjustment to the final purchase price in April 2011 for actual cash and working capital balances as of the date of the sale.

Notes to Consolidated Financial Statements

The following provides a summary of the discontinued operations presented in the consolidated statements of income for the periods indicated:

(Thousands)	Period January 1, to November 16, 2010	Year Ended December 31, 2009
Operating Revenues		
Sales and services	**$643,533**	$748,371
Operating Expenses		
Natural gas purchased	**366,726**	418,545
Depreciation and amortization	**21,540**	45,657
Goodwill impairment	**275,802**	-
Other operating expenses	**165,786**	223,440
Total Operating Expenses	**829,854**	687,642
Operating (Loss) Income	**(186,321)**	60,729
Other (Income) Deductions, net	**(6,140)**	(1,533)
Loss on Sale of Natural Gas Companies	**88,243**	-
Interest Charges, Net	**28,292**	35,013
(Loss) Income Before Income Taxes	**(296,716)**	27,249
Taxes on Sale of Natural Gas Companies	**18,300**	-
Income Taxes	**23,881**	3,115
(Loss) Income From Discontinued Operations	**$(338,897)**	$24,134

The above Depreciation and amortization expense excludes approximately $21 million of depreciation and amortization for the period of time that we classified the assets as held for sale. The amount of Interest Charges, Net represents interest on the direct obligations of the natural gas companies sold. Transaction costs of $2 million are included in the loss on sale.

The following table provides the carrying amounts of the major classes of assets and liabilities of the discontinued operations as of the dates indicated.

(Thousands)	Nov. 16, 2010	Dec. 31, 2009
Assets		
Current assets	$307,090	$339,472
Utility plant, net	961,961	956,390
Regulatory assets	390,831	405,751
Goodwill	267,132	542,934
Other assets	28,401	40,647
Total assets of discontinued operations	$1,955,415	$2,285,194
Liabilities		
Current liabilities	$127,842	$141,408
Regulatory liabilities	335,846	339,166
Long-term debt, including current portion	381,000	424,000
Other liabilities	377,754	377,288
Total liabilities of discontinued operations	$1,222,442	$1,281,862

Note 3. Goodwill

We do not amortize goodwill, but test it for impairment at least annually. Impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of our marginal, weighted-average cost of capital, and forecasted cash flows. We test the reasonableness of the conclusions of our impairment testing using a range of discount rates and a range of assumptions for long-term cash flows. Our decision in May 2010 to sell the natural gas companies helped meet a key strategic objective of our parent, Iberdrola S. A., as it allows us to focus on electric operations. The decision to sell represented a triggering event and we immediately performed an impairment test of the goodwill for SCG, CNG and BGC in accordance with the two step process described in Note 1. We determined that the carrying value of the combined companies exceeded the purchase price agreed to by UIL, resulting in a goodwill impairment of $275.8 million. We had no impairment of goodwill in 2010 or 2009 as a result of our annual impairment testing, which we perform in the third quarter each year. No impairment was indicated within any of the ranges of assumptions analyzed for our New York, Maine or nonutility reporting units. There were no events or circumstances subsequent to our annual impairment testing that required us to update the test.

The carrying amount of goodwill as of December 31, 2010 and 2009, is shown in the following table. Goodwill has not been adjusted to reflect Iberdrola's purchase of Energy East.

	2010	**2009**
(Thousands)		
Balance as of January 1		
Goodwill	**$1,526,822**	$1,526,598
Accumulated impairment losses	**(242)**	-
	1,526,580	1,526,598
Preacquisition income tax adjustments	**-**	838
Goodwill related to sale of business units	**(267,132**)	(614)
Impairment for natural gas companies sold	**(275,802)**	-
Impairment for Bridgeport	**-**	(242)
Balance as of December 31		
Goodwill	**983,888**	1,526,822
Accumulated impairment losses	**(242)**	(242)
	$983,646	$1,526,580

In May 2008 TEN Cos. and the state of Connecticut (State) signed a memorandum of understanding (MOU) to allow interested parties to finalize an agreement for the State's purchase of certain heating and cooling equipment that serves certain state buildings (Capitol Area System) at a specified purchase price of $10.6 million, along with other terms specified in the MOU. TEN Cos. entered into an Asset Purchase Agreement (Agreement) contemplated in the MOU with the State in November 2008. The State passed legislation authorizing the Agreement and the sale was completed on June 1, 2009. The sale resulted in a $614 thousand decrease in goodwill.

Note 4. Income Taxes

Year Ended December 31,	2010	2009
(Thousands)		
Current		
Federal	**$(259,708)**	$(114,866)
State	**(6,594)**	3,676
Current taxes charged to expense	**(266,302)**	(111,190)
Deferred		
Federal	**234,214**	118,192
State	**10,237**	(11,814)
Deferred taxes charged to expense	**244,451**	106,378
Investment tax credit adjustments	**(2,273)**	(2,295)
Total for Continuing Operations	**$(24,124)**	$(7,107)

The significant decrease in current income tax expense in 2010, and corresponding increase in deferred income tax expense as compared to 2009 is driven primarily by the tax depreciation related to our Tax equity investment in Aeolus VI made on December 2010 as well as a full year's worth of tax depreciation related to our Tax equity investment in Aeolus V made in April of 2009. (See Note 8.)

Our tax expense differed from the expense at the statutory rate of 35% due to the following:

Year Ended December 31,	2010	2009
(Thousands)		
Tax expense at statutory rate	**$37,740**	$28,483
Depreciation and amortization not normalized	**11,669**	9,521
Investment tax credit amortization	**(2,273)**	(2,295)
Removal costs	**(7,847)**	(5,942)
Medicare subsidy	**2,708**	(3,731)
Tax return and audit adjustments	**(3,341)**	(14,232)
Tax equity investment depreciation not normalized	**(37,031)**	-
Tax equity investment production tax credits	**(24,245)**	(14,543)
State taxes, net of federal benefit	**2,368**	(5,290)
Other, net	**(3,872)**	922
Total for Continuing Operations	**$(24,124)**	$(7,107)

Income taxes were $61.8 million less in 2010 than they would have been at the federal statutory rate of 35% and $35.6 million less in 2009. The 2010 effective tax rate was less than the statutory rate primarily due to the tax benefits, including production tax credits, generated from our Tax equity investments in two wind farm partnerships, offset by the increase in taxes related to the depreciation and amortization not normalized. The 2009 effective tax rate was less than the statutory rate primarily due to the recording of a deferred tax asset related to production tax credits generated as a result of our Tax equity investment in a wind farm partnership and the flow-through effect of the tax deduction related to previously capitalized repair costs taken for CMP on the 2008 return filed in 2009.

Our consolidated deferred tax assets and liabilities consisted of:

December 31,	2010	2009
(Thousands)		
Current Deferred Income Tax Assets	**$62,081**	$37,500
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property related	**$1,379,484**	$1,377,569
Pension	**249,182**	243,737
Unfunded future income taxes	**166,764**	150,306
Deferred (gain) on sale of generation assets	**26,008**	38,248
Accumulated deferred investment tax credits	**23,753**	26,805
Federal and state net operating loss carryforwards	**(50,985)**	(80,382)
Other postretirement benefits	**(102,163)**	(101,966)
Positive benefits adjustments merger order	**(79,365)**	(118,028)
Other	**(25,994)**	(14,831)
Total Noncurrent Deferred Income Tax Liabilities	**1,586,684**	1,521,458
Less amounts classified as regulatory liabilities		
Deferred income taxes	**368,564**	367,764
Noncurrent Deferred Income Tax Liabilities	**$1,218,120**	$1,153,694
Deferred tax assets	**$320,588**	$352,707
Deferred tax liabilities	**1,845,191**	1,836,665
Net Accumulated Deferred Income Tax Liabilities	**$1,524,603**	$1,483,958

Iberdrola USA and its subsidiaries have the following loss carry-forward amounts: state of New York - $682 million, Maine - $503 million, and various other unitary states of $1 million which expire between 2027 and 2030. We have not recorded a valuation allowance because we believe we will be able to fully utilize the loss carryforwards.

Reconciliation of Gross Income Tax Reserves	2010	2009
(Thousands)		
Balance as of January 1	**$39,498**	$4,702
Increases for tax positions related to prior years	**-**	38,142
Reductions for tax positions related to prior years	**-**	(3,346)
Disposition of amounts related to sale of natural gas companies	**(6,788)**	-
Balance as of December 31	**$32,710**	$39,498

The total gross unrecognized tax benefits as of December 31, 2010, were $35.3 million, including gross income tax reserves of $32.7 million and interest of $2.6 million. Including interest, $8.3 million of the total gross unrecognized tax benefits would affect the effective tax rate, if recognized. Gross income tax reserves decreased $6.8 million in 2010 primarily due to the sale of the natural gas companies.

We have been audited through 2005 for federal income taxes. The statute of limitations in all state jurisdictions has expired for all years through 2006. Our federal returns for 2006 through 2009 are currently under review. We anticipate that the reviews will be completed in 2011. We cannot predict the ultimate outcome of the reviews.

As a result of the passage of The Small Business Jobs Act in September 2010 and the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 in December 2010, certain capital additions qualify for 50% bonus depreciation and 100% expensing, respectively, for tax purposes. Iberdrola USA and its affiliates have elected to apply the 50% bonus and 100% expensing to the additions it has determined qualify for this accelerated tax depreciation. There is no earnings impact related to this election as the accelerated tax depreciation creates a temporary difference that requires the establishment of a deferred tax liability.

***Elimination of tax deduction related to Medicare Part D Subsidy*:** The Patient Protection and Affordable Care Act (PPACA) and the Health Care and Education Reconciliation Act of 2010 (H.R. 4872) were signed into U.S. law in late March 2010. We receive a federal subsidy because we sponsor retiree health benefit plans that provide a benefit that is at least actuarially equivalent to the benefits under Medicare Part D. The subsidy is known as the Retiree Drug Subsidy (RDS or the subsidy). The RDS payments we receive are not currently taxed. A provision in the PPACA changes the tax treatment of the RDS, requiring the amount of the subsidy received to be offset against the amount of retiree health care payments that would be eligible for a tax deduction. As a result, the subsidy received would reduce an employer's tax deduction for the costs of retiree health care. Our subsidy receipts will effectively become taxable in tax years that begin after December 31, 2012.

In accordance with U.S. GAAP concerning accounting for income taxes, a reporting entity is required to immediately recognize the effect of a change in tax law in continuing operations in the income statement in the period that includes the enactment date. We recorded the effect of the change related to the RDS in the quarter ended March 31, 2010, due to the fact that we accounted for the future tax benefit on an accrual basis. In accounting for the effect of the change for U.S. GAAP reporting, an employer that captured the tax benefit of future subsidies on an accrual basis would now be required to reduce the accumulated deferred tax asset on its balance sheet related to the accrued estimated deductible retiree health care payments to reflect the fact that the future deduction will now be reduced by the collection of the accrued subsidy.

Companies that meet the requirements concerning accounting for regulated operations offset that decrease with the establishment of a regulatory asset. As a result, we have recorded a regulatory asset for unfunded future income taxes of approximately $26 million and reduced our deferred income tax asset related to the costs of retiree health care by approximately $17 million for NYSEG and RG&E combined. In addition, because the recognition of the unfunded future income tax regulatory asset is considered a temporary difference, we have recognized an associated deferred income tax liability of approximately $9 million. There is no immediate effect on the income statement under this accounting, only our balance sheet is affected. The amortization of the $26 million regulatory asset and associated $9 million deferred tax liability commenced on September 1, 2010 in accordance with the provisions of the NYSEG and RG&E rate settlements. The amortization period is 40 months.

CMP recorded a $5.6 million income tax expense as a result of the tax law change and is seeking recovery of approximately $3.5 million of that amount pursuant to the mandated cost provision of its current rate plan.

Note 5. Long-term Debt

At December 31, 2010 and 2009, our consolidated long-term debt was:

Company		Interest Rates	Maturity	Amount (Thousands) 2010	2009
	First mortgage bonds [1]				
RG&E	Series TT, WW, VV, XX & YY	5.90% - 8.00%	2011 - 2033	**$536,000**	$636,000
RG&E	PCN 2004 Series A	4.75%	2016	**10,500**	10,500
RG&E	PCN 2004 Series B	5.375%	2032	**50,000**	50,000
RG&E	PCN Series C	5.00%	2016	**29,350**	29,350
CMP	Series A	5.70%	2019	**150,000**	150,000
SCG	Medium Term Notes I, II, III & IV	5.772% - 7.95%	2010 - 2037	**-**	234,000
Berkshire Gas	Series P	10.06%	2019	**-**	10,000
Total first mortgage bonds				**775,850**	1,119,850
	Unsecured pollution control notes (PCNs), fixed				
NYSEG	1985 Series A, B & D	4.00% - 4.10%	2015	**132,000**	132,000
NYSEG	1994 Series B & C	3.00%	2013	**101,000**	-
NYSEG	2004 Series B & C	3.245% - 5.35%	2028 - 2034	**70,000**	170,000
NYSEG	2006 Series A	3.00%	2013	**12,000**	-
RG&E	1998 Series A	5.95%	2033	**25,500**	25,500
CMP	Industrial Development Authority of the state of New Hampshire Notes	5.375%	2014	**19,500**	19,500
Total unsecured pollution control notes, fixed				**360,000**	347,000
	Unsecured PCNs, variable				
NYSEG	2006 Series A	.27%	2024	**-**	12,000
NYSEG	2005 Series A	.25%	2026	**25**	1,550
NYSEG	2004 Series A	.25%	2027	**175**	175
NYSEG	2004 Series C	.70%	2034	**100,000**	-
NYSEG	1994 Series B, C, D1 & D2	.17% - .24%	2029	**-**	175,000
RG&E	1997 Series A & B	.60%	2032	**68,000**	68,000
Total unsecured pollution control notes, variable				**168,200**	256,725
	Various long-term debt				
NYSEG	Unsecured Notes	5.50% - 6.15%	2012 - 2023	**600,000**	600,000
CMP	Series E & F Medium Term Notes	5.10% - 7.00%	2011 - 2037	**293,200**	293,200
CNG	Medium Term Notes Series A, B, C & D	5.63% - 9.10%	2012 - 2037	**-**	150,000
Berkshire Gas	Unsecured Notes	4.76% - 9.60%	2011 - 2021	**-**	30,000
Chester	Promissory and Senior Notes	7.05% - 10.48%	2020	**11,640**	12,823
Total various long-term debt				**904,840**	1,086,023
Obligations under capital leases				**15,537**	18,897
Unamortized premium (discount) on debt, net				**3,962**	3,940
				2,228,389	2,832,435
Less debt due within one year, included in current liabilities				**89,055**	233,502
Total Other long-term debt				**2,139,334**	2,598,933
	Long-term debt owed to affiliates				
Iberdrola USA	Unsecured Notes	5.90%	2013	**300,000**	300,000
Iberdrola USA	Unsecured Notes	7.08%	2019	**350,000**	1,050,000
Total Long-term debt owed to affiliates				**650,000**	1,350,000
Total Long-term Debt				**$2,789,334**	$3,948,933

[1] The first mortgage bonds are secured by liens on substantially all of the respective utility's properties.

Notes to Consolidated Financial Statements

In April 2009 the obligor on our $1.3 billion of outstanding unsecured debt was transferred to Iberdrola International, a subsidiary of Iberdrola S.A. In exchange we entered into a debt agreement with Scottish Power, Limited (Scottish Power), another subsidiary of Iberdrola S.A., for $1.05 billion and received an equity infusion of $250 million from Iberdrola S.A. In May 2009 we borrowed an additional $300 million from Scottish Power. On November 17, 2010, we repaid $400 million of the debt, at a premium of $82 million, and on December 29, 2010, we repaid $300 million of the debt at a premium of $46 million.

In June 2010 NYSEG converted $113 million of variable-rate pollution control notes (PCNs) (1994 Series B & C and 2006 Series A) to fixed rate mandatory tender bonds due in 2013. Concurrent with that transaction NYSEG redeemed and did not remarket an additional $74 million of its variable-rate PCNs (1994 Series D1 & D2) and terminated a $190 million credit facility that had served as backstop liquidity for the variable rate PCNs prior to their conversion or redemption.

On December 30, 2010, RG&E completed a make-whole redemption of $100 million of 6.95% Series TT first mortgage bonds, due in April 2011, at a premium of $1.6 million, using excess cash on hand.

There are federal and state regulatory restrictions on our ability to borrow funds from our utility subsidiaries. While we may be able to borrow funds from our utility subsidiaries by obtaining regulatory approvals and meeting certain conditions, we do not expect to seek such loans. Iberdrola USA has no secured indebtedness and none of its assets are mortgaged, pledged or otherwise subject to lien. None of Iberdrola USA’s debt obligations are guaranteed or secured by its subsidiaries.

As of December 31, 2010, NYSEG and RG&E had outstanding $598 million of tax-exempt PCNs, of which $278 million have coupons fixed to maturity, $113 million are notes with a mandatory redemption date in 2013, $40 million are notes with a mandatory redemption date in 2016, $100 million are 7-day auction rate notes and $68 million are 35-day auction rate notes. The notes with mandatory redemption dates in 2013 and 2016 have maturity dates in 2024 through 2032 and may be remarketed as tax-exempt bonds in a different interest rate mode after the mandatory redemptions.

As of December 31, 2009, NYSEG and RG&E had outstanding $674 million of tax-exempt PCNs, of which $277 million had coupons fixed to maturity, $40 million were notes with a mandatory redemption date in 2016, $100 million were auction rate notes under a special rate period where the rate was fixed until January 2010, $187 million were weekly VRDNs, $2 million were 7-day auction rate notes and $68 million were 35-day auction rate notes.

In August 2008 NYSEG and RG&E began to place orders for their own accounts in the auctions. NYSEG and RG&E bid at each auction for 100% of the outstanding securities at the greater of the one-month London Interbank Offer Rate (LIBOR) or the Securities Industry and Financial Markets index. In August 2009 RG&E remarketed, as mandatory tender bonds, the securities it held pursuant to this program. NYSEG continued to bid on $99 million of its auction rate notes during 2010 and 2009. At December 31, 2010, NYSEG held a total of $99 million of those securities, and $97 million at December 31, 2009.

In August 2009 RG&E converted PCN 1997 Series C and PCN 2004 Series A from auction rate to mandatory tender bonds, with 2016 tender dates. Those two series had been subject to the program described above wherein RG&E was bidding for the securities at auction. At the time of the conversion, RG&E held $33 million of PCN 1997 Series C bonds and $11 million of PCN 2004 Series A bonds. Also at the time of conversion, RG&E retired $4.6 million of PCN 1997 Series C bonds in connection with the closing of its Russell Station. After the conversion, there were $29 million of PCN 1997 Series C bonds and $11 million of PCN 2004 Series A bonds outstanding.

As of February 11, 2011, NYSEG and RG&E were:
- Paying rates averaging 0.67% on the remaining $168 million of auction rate notes for which they are not placing orders at auction.
- Paying rates averaging 0.27% on the $99 million of auction rates notes on which they are placing orders at auction, substantially all of which are being held on account and have been accounted for as a redemption of long-term debt.

In June 2009 RG&E issued $150 million Series YY first mortgage bonds bearing a coupon of 5.9% and with a maturity date of July 15, 2019. The proceeds of the issuance funded the redemption at maturity of $100 million of Series B Medium Term Notes in October 2009. The remainder of the funds were used to reduce short-term debt and for general corporate purposes. RG&E settled its October 2009 hedge in June 2009 at a loss of $20.9 million in connection with the pricing of those Series YY Bonds.

In May 2009 CMP issued $150 million Series A first mortgage bonds bearing a coupon of 5.7% and with a maturity date of June 1, 2019. The proceeds of the issuance were used to reduce short-term debt and for general corporate purposes. CMP had entered into two derivative transactions – forward starting swaps – to hedge that financing transaction. CMP settled the hedges in May 2009 at a loss of $19.9 million.

The above hedge losses are included in other comprehensive income and are being amortized to interest expense over the term of the related new debt that was issued.

At December 31, 2010, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years is:

2011	2012	2013	2014	2015
$89,055	$155,606	$451,862	$22,724	$134,755

Cross-default provisions**:** Iberdrola USA has a provision in its revolving credit facility, which provides that its default with respect to any other debt in excess of $50 million will be considered a default under its revolving credit facility.

We are in compliance with all debt covenants as of December 31, 2010 and 2009.

Note 6. Bank Loans and Other Borrowings

Iberdrola USA is the sole borrower in a revolving credit facility providing maximum borrowings of up to $300 million. Our operating utilities are joint borrowers in a revolving credit facility providing maximum borrowings of up to $475 million in aggregate. Sublimits that total to the aggregate limit apply to each joint borrower and can be altered within the constraints imposed by maximum limits that apply to each joint borrower. Both facilities have expiration dates in 2012 and require fees on undrawn borrowing capacity. One of our operating utilities has uncommitted bilateral credit agreements for a total of $5 million. The two revolving credit facilities and the one bilateral credit agreement provided for consolidated maximum borrowings of $780 million at December 31, 2010, and $785 million at December 31, 2009. Iberdrola USA pays a facility fee of 6 basis points annually on its $300 million revolver and each joint borrower pays a facility fee on its revolver sublimit, ranging from 6 to 10 basis points annually depending on the rating of its unsecured debt.

We use drawings on our credit facilities to finance working capital needs, to temporarily finance certain refundings and for other corporate purposes. Drawings on Iberdrola USA's revolving credit facility are used to provide financing to its nonregulated subsidiaries and can be used to provide additional financing to its operating utilities. There was $142 million of such short-term debt outstanding at December 31, 2010, and $119 million outstanding at December 31, 2009. The weighted-average interest rate on short-term debt was .5% at December 31, 2010, and 2009. At February 10, 2011, there was $152 million of such debt outstanding.

In our revolving credit facility we covenant not to permit, without the consent of the lender, our ratio of consolidated indebtedness to consolidated total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to consolidated total capitalization, the facility excludes from consolidated net worth the balance of Accumulated other comprehensive income (loss) as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness Iberdrola USA may maintain. Continued unremedied failure to comply with those covenants for 15 days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of consolidated indebtedness to consolidated total capitalization pursuant to the revolving credit facility was 0.48 to 1.00 at December 31, 2010. We are not in default as of December 31, 2010.

In the revolving credit facility in which our operating utilities are joint borrowers, each joint borrower covenants not to permit, without the consent of the lender, its ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to total capitalization, the facility excludes from consolidated net worth the balance of Accumulated other comprehensive income (loss) as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness each borrower may maintain. Continued unremedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity for the party in default. We are not in default as of December 31, 2010.

Note 7. Redeemable Preferred Stock of Subsidiaries, Noncontrolling Interests

The redeemable preferred stock of subsidiaries are noncontrolling interests because they contain a feature that allows the holders to elect a majority of the subsidiary's board of directors if preferred stock dividends are in default in an amount equivalent to four full quarterly dividends. Such a potential redemption-triggering event is not solely within the control of the subsidiary.

At December 31, 2010 and 2009, our consolidated redeemable preferred stock, noncontrolling interests was:

Subsidiary and Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding[1]	Amount (Thousands) 2010	2009
CMP, 6% Noncallable	$100	-	2,347	**$235**	$518
CMP, 4.60%	100	101.00	11,664	**1,167**	3,000
CMP, 4.75%	100	101.00	9,028	**903**	5,000
CMP, 5.25%	100	102.00	-	**-**	5,000
NYSEG, 3.75%	100	104.00	78,379	**7,838**	7,838
NYSEG, 4.50% (1949)	100	103.75	11,800	**1,180**	1,180
NYSEG, 4.40%	100	102.00	7,093	**709**	709
NYSEG, 4.15% (1954)	100	102.00	4,317	**432**	432
NYSEG, Limited Voting Junior	1	-	1	**-**	-
RG&E, Limited Voting Junior	1	-	1	**-**	-
Berkshire Gas, 4.80%	100	100.00	-	**-**	118
CNG, 6.00%	100	110.00	-	**-**	410
CNG, 8.00% Noncallable	3.125	-	-	**-**	340
Total				**$12,464**	$24,545

[1] At December 31, 2010, Iberdrola USA and its subsidiaries had 6,632,519 shares of $100 par value preferred stock, 16,800,000 shares of $25 par value preferred stock, 1,000,000 shares of $100 par value preference stock and 5,000,000 shares of $1 par value preference stock authorized but unissued.

During 2010 we redeemed through tender offer $11.2 million of various series of CMP's outstanding preferred stock.

Note 8. Tax Equity Investments

In April 2009 Iberdrola USA, through its subsidiary CNE Energy, acquired an interest in Aeolus Wind Power V LLC (Aeolus V) in exchange for $305.4 million in cash. CNE Energy purchased its membership interest in Aeolus V from PPM Wind Energy LLC (PPM), an affiliate, which contributed its 100% ownership of various wind farms to Aeolus V.

The main characteristics of our investment in Aeolus V are as follows:

- PPM retains day-to-day management of the wind farms. Defined major decisions require consent from CNE Energy.
- As a minority shareholder, CNE Energy has the right to a substantial portion of the profits and tax credits generated by the wind farms up to the return level established at the beginning of the investment contract.
- CNE Energy initially holds a 50% interest in Aeolus V until it achieves a stipulated 7.5% return, after which it is entitled to maintain a 5% ownership interest.
- PPM has the option to purchase, at fair market value, CNE Energy's remaining residual equity interest, which is exercisable after CNE Energy achieves its agreed upon return.
- Whether or not CNE Energy obtains the agreed upon return depends on the economic performance of the wind farms. While PPM is bound to operate and maintain the facilities in an efficient manner and maintain appropriate insurance, it is not obligated to deliver cash to CNE Energy over and above the aforementioned profits and tax credits.

On December 17, 2010, we acquired, also through CNE Energy, an interest in Aeolus Wind Power VI LLC (Aeolus VI) in exchange for $236.0 million in cash. CNE Energy purchased its membership interest in Aeolus VI from PPM, which contributed its 100% ownership of four wind farms to Aeolus VI. The partnership terms for Aeolus VI are similar to the terms described above for Aeolus V.

CNE Energy uses an equity method referred to as Hypothetical Liquidation at Book Value (HLBV) to account for its investments in Aeolus V and in Aeolus VI. The application of that method results in CNE Energy recording a gain or loss on its investment based on the cash implications of a liquidation at book value, with a corresponding adjustment to the investment account. In addition, the HLBV method requires the tax effects related to Production Tax Credits (PTCs) (applies to Aeolus V only) and taxable income (loss) to be recorded in income taxes on the income statement. The primary difference in accounting for the Aeolus VI investment is that the Aeolus VI wind farms received cash grants from the federal government and consequently are not eligible for PTCs. Finally, the HLBV method requires a credit to accumulated deferred income taxes on the balance sheet and a debit to income taxes on the income statement for an amount representing the statutory rate applied to the difference between the tax basis and the book basis of the investment.

The following table shows the effects of our investments on our consolidated income statements and balance sheets:

Income statement for the year ended December 31,	**2010**	**2009**
(Thousands)		
Other (deductions), losses from tax equity investments	$(62,805)	$(579)
Income tax (benefit)	(83,258)	(14,746)
Total income statement benefit	$20,453	$14,167

Balance sheet at December 31,	**2010**	**2009**
(Thousands)		
Tax equity investment	$478,016	$304,821
Deferred tax liabilities, noncurrent	$(151,149)	$(32,964)
Prepaid income taxes	-	$47,709

The following table provides summary financial information for Aeolus V and Aeolus VI:

Income statement for the year ended December 31,	**2010**	**2009**
(Thousands)		
Revenues*	$84,958	$51,070
Operating income	$26,757	$13,564
Net Income (Loss)	$2,097	$(1,048)

*Including PTCs for Aeolus V only.

Balance sheet at December 31,	**2010**	**2009**
(Thousands)		
Total Assets	$2,050,155	$686,386
Total Equity	$1,700,201	$674,948

Note 9. Commitments and Contingencies

***Capital spending*:** We have commitments in connection with our capital spending program. We plan to invest approximately $3.8 billion in our energy delivery infrastructure during the next five years, including amounts dedicated to electric reliability. We expect that about three-fourths of our capital spending will be paid for with internally generated funds and the remainder through the issuance of debt securities. The program is subject to periodic review and revision. Our capital spending will be primarily for the extension of energy delivery service, increased transmission capacity, necessary improvements to existing facilities and compliance with environmental requirements and governmental mandates.

On June 10, 2010, the Maine Public Utilities Commission granted approval for CMP's Maine Power Reliability Program (MPRP). The MPRP, expected to be completed in 2015, is a $1.4

billion project that will support the development of new renewable energy resources and help ensure long-term reliability for customers by increasing the capacity and efficiency of the New England transmission grid. The MPRP includes the construction of five new 345-kilovolt substations and related facilities linked by approximately 450 miles of new or rebuilt transmission lines. The project is the first upgrade of CMP's electricity grid in 40 years.

CMP's Advanced Metering Infrastructure (AMI) project, expected to be completed by the end of 2012, will provide its approximately 620,000 residential, commercial and industrial customers with information on electrical usage, allowing them to better manage energy use and cost. The new meters will also help CMP reduce costs, enhance system planning and pinpoint problems more quickly during outages. Reduced costs will result from operational efficiencies related to billing, account openings and closings, and credit and collections as well as instantaneous meter reading. The total estimated cost of the AMI project is $166 million, and is being funded in part by a $96 million grant from the U.S. Department of Energy (DOE), which was approved on April 26, 2010.

A Smart Grid Investment Grant (SGIG) was awarded to and is administered through the NYISO to the New York transmission owners, which include NYSEG and RG&E. The DOE awarded the grant to the NYISO, which concluded a sub-recipient agreement with NYSEG and RG&E on May 5, 2010. According to the grant the DOE will reimburse NYSEG and RG&E, through the NYISO, a total of approximately $7.3 million for two projects at each company. NYSEG and RG&E will each spend a matching amount on the projects to bring the total value of the SGIG project to approximately $14.6 million. The SGIG for each company consists of a project to add switched capacitors to its electric grid and another project to install phasor measurement units to the grid. The new equipment will improve the voltage stability of the New York electric grid and enhance the efficiency of power flows across New York, thereby reducing the cost and increasing the reliability of electric power for New York consumers. The companies expect to complete the projects by the end of July 2013.

On November 30, 2010, NYSEG executed a $29.6 million cooperative funding agreement with the DOE as part of the agency's Smart Grid Demonstration Program. As a result, NYSEG launched a comprehensive feasibility study of a compressed air energy storage (CAES) facility. Compressed air would be pumped into a depleted underground salt cavern when low-cost, off-peak electricity is available to power the compressors. The compressed air could then be released to spin a turbine and generate electricity as needed, particularly during times of high customer demand. The feasibility study, to be completed in late 2011, will evaluate the technical and economic viability of CAES technology as an integral part of promoting stable electricity transmission system operation and the continued development of renewable energy. If the study confirms that CAES is feasible and economical, NYSEG would seek approval from state and federal agencies to proceed with construction of the plant with a target in-service date of late 2014.

Merger order: The Iberdrola merger order contained a capital expenditure condition for NYSEG and RG&E of an aggregate $540 million during 2009 and 2010. In September 2009 we requested a limited waiver of the capital expenditure merger condition to allow us to spend our capital investment by 2011. The New York State Public Service Commission (NYPSC) denied the request in its order issued in April 2010. If NYSEG and RG&E were to spend less than the amount targeted in the merger order, they were obligated to provide a calculation of the revenue requirement effect resulting from the actual level of capital spending compared to the targeted amount, which could be returned to customers if ordered by the NYPSC.

NYSEG and RG&E were also afforded the opportunity to provide an assessment of other considerations, including the effects on customers associated with a lower level of capital spending, and to provide reasons why the total revenue requirement effect, as calculated, should not be returned to customers. NYSEG and RG&E made their required filing on January 31, 2011. In that filing they informed the NYPSC that their capital expenditures for 2009 and 2010 totaled $546.7 million, or $6.7 million more than the $540 million merger condition, in the aggregate. NYSEG's electric and natural gas businesses and RG&E's natural gas business invested more than their required expenditure levels, but RG&E's electric business invested less than its required expenditure level. In their filing, the companies also demonstrate that a deferral of any revenue requirement effect (in the form of a customer credit/regulatory liability) is unnecessary because: 1) in aggregate NYSEG and RG&E met the capital expenditure condition, 2) they continue to provide safe and reliable service and 3) RG&E's lower electric capital expenditures resulted in a customer benefit due to lower revenue requirements.

Staff allegations concerning earnings sharing calculations: The New York Department of Public Service Staff (Staff) in its testimony and briefs in the merger proceeding alleged that NYSEG did not properly compute the amount due to customers under the electric ESM in NYSEG's electric rate plan that was in effect from 2002 through 2006. The Staff claimed that its preliminary analysis showed an additional $67 million, including interest, that should have been allocated to customers. The Staff also raised issues with regard to the ESM under the RG&E electric rate plan currently in effect, but had not completed its analysis.

In its testimony on January 22, 2010, the NYPSC provided a detailed analysis of the issue. The Staff proposed a one-time charge of $107 million relating to the companies' annual compliance filings including the calculation of the ESM and accounting for certain software costs. The companies vigorously dispute Staff's claims, but could not predict at that time how the matters would be resolved. As of December 31, 2009, the companies reduced their regulatory assets by $40 million with an offsetting charge to other operating expense due to the uncertainty related to this proceeding. The recent rate case settlement, which the NYPSC approved on September 16, 2010, includes a resolution of those issues as part of the overall settlement. The amount the companies recognized in 2009 is approximately the same as the amount included in the settlement. (See Note 15.)

Homer City: In June 2008 NYSEG received a letter from subsidiaries of Edison Mission Energy regarding a notice of violation (NOV) from the U. S. Environmental Protection Agency (EPA) claiming that certain modifications to the Homer City Electric Generation Station (Homer City) during the time it was owned by NYSEG and Pennsylvania Electric Company (Penelec) were done in violation of EPA's new source review (NSR) regulations. Homer City was sold in 1999 to Edison Mission Energy by NYSEG and Penelec. Edison Mission Energy asserts that it is entitled to indemnification for certain fines, penalties and costs arising out of the violations alleged in the NOV under the terms of the Asset Purchase Agreement for Homer City. That appears to be the same claim Edison Mission Energy made to NYSEG in October 2000. NYSEG continues to believe that the costs sought by Edison Mission Energy are not liabilities of NYSEG and therefore did not retain liability for those material claims.

In September 2008 NYSEG, Penelec and Edison Mission Energy met with the EPA for a required NOV conference. EPA indicated at the meeting that it seeks a system-wide NSR settlement covering Edison Mission Energy's entire generation fleet, including a number of plants in Illinois, and would require installation of scrubbers on Homer City Units 1 and 2 as part of the settlement. In April 2009 EPA sent Edison Mission Energy a settlement proposal that included those controls, along with specified emissions caps, operational controls, improvement projects and fines. To our knowledge, Edison Mission Energy has not yet formally responded to EPA's proposal. While the EPA's settlement proposal substantially increases the potential value of the claim, NYSEG believes it has sound contractual defenses under the Asset Purchase Agreement. NYSEG estimates that its most likely cost exposure over the next several years will be primarily for legal defense costs and, potentially, a proportionate share of fines EPA may assess against Edison Mission Energy.

In connection with this matter, on January 6, 2011, the U. S. Justice Department filed a lawsuit on behalf of the EPA in the U.S. District Court for the Western District of Pennsylvania against current and former owners and operators of Homer City. NYSEG and Penelec are named in the suit, along with EME Homer City Generation, the current operator, and eight limited liability companies who own the plant by virtue of a sale and leaseback refinancing that occurred in 2001. NYSEG believes it has a number of sound defenses to the claims included in the lawsuit, including that the statute of limitations and equitable principles prohibit EPA from forcing NYSEG to pay for costly improvements at a plant it has not owned or operated in over 10 years. NYSEG cannot predict the nature or amounts of any potential fines or penalties.

Nonutility generator power purchase contracts**:** We expensed approximately $71 million for NUG power in 2010 and $218 million in 2009. We estimate that our NUG power purchases will total $72 million in 2011, $65 million in 2012, $63 million in 2013, $63 million in 2014 and $64 million in 2015.

Nuclear entitlement power purchase contracts**:** In connection with our sales of nuclear generating assets in 2001 and 2004, we entered into four entitlement contracts under which we purchase electricity at a fixed contract price. We expensed approximately $292 million for nuclear entitlement power in 2010 and $290 million in 2009. We estimate that our nuclear entitlement power purchases will be $281 million in 2011, $191 million in 2012, $203 million in 2013, $87 million in 2014 and $3 million in 2015.

Note 10. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric and natural gas service.

The EPA and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at 24 waste sites. The 24 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 24 sites, 15 sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites, four are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and four sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $1 million related to 12 of the 24 sites. We have paid remediation costs related to the remaining 13 sites, and do not expect to incur any additional liability. We have recorded an estimated liability of $3.6 million related to another 12 sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties. The ultimate cost to remediate the sites may be significantly more than the accrued amount. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us.

We have a program to investigate and perform necessary remediation at our 52 sites where gas was manufactured in the past. Eight sites are included in the New York State Registry, eight sites are included in the New York Voluntary Cleanup Program, three sites are part of Maine's Voluntary Response Action Program and those two sites are part of Maine's Uncontrolled Sites

Program. We have entered into consent orders with various environmental agencies to investigate and, where necessary, remediate 44 of the 52 sites.

Our estimate for all costs related to investigation and remediation of the 52 sites ranges from $204 million to $406 million at December 31, 2010. Our estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $204 million at December 31, 2010, and $213 million at December 31, 2009. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis unless payments are fixed and determinable. Nearly all of our environmental liability accruals, which are expected to be paid through the year 2030, have been established on an undiscounted basis. Some of our operating utility subsidiaries have received insurance settlements during the last two years, which they accounted for as reductions to their related regulatory assets.

Note 11. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet.

The financial instruments we hold or issue are not for trading or speculative purposes.

Commodity price risk: Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging activities.

Effective beginning January 1, 2010, NYSEG and RG&E no longer offer fixed price service to their customers. They currently have a nonbypassable wires charge adjustment that allows them to pass through rates any changes in the market price of electricity. They use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2010, the gain recognized in regulatory liabilities was $1.1 million for electricity derivatives. For the year ended December 31, the gain (loss) reclassified from regulatory assets into income, which is included in electricity purchased, was $5.6 million for 2010 and $(6.9) million for 2009.

All of our natural gas utilities have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. NYSEG and RG&E use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2010, the loss recognized in regulatory assets was $12.8 million for natural gas hedges. For the year ended December 31, the gain (loss) reclassified from regulatory assets into income, which is included in natural gas purchased, was $(21.8) million for 2010 and $50.1 million for 2009.

Energetix, Inc. and NYSEG Solutions, Inc. offer retail electric and natural gas service to customers in New York State and actively hedge the load required to serve customers that have chosen them as their commodity supplier. As of January 5, 2011, the energy marketing subsidiaries' expected fixed price loads were fully hedged for 2011. A fluctuation of $1.00 per Megawatt-hour in the average price of electricity would change earnings less than $100,000 in 2011. The percentage of hedged load for the energy marketing subsidiaries is based on load forecasts, which include certain assumptions such as historical weather patterns. Actual results could differ as a result of changes in the load compared to the load forecast.

Those two companies designate financial electricity contracts as cash flow hedging instruments. We record changes in the fair value of the cash flow hedging instruments in other comprehensive income (OCI), to the extent they are considered effective, and reclassify those gains or losses into earnings in the same period or periods during which the hedged transactions affect earnings. We record the ineffective portion of any change in fair value of cash flow hedges to the income statement as either Other (Income) or Other Deductions, as appropriate.

Our derivative volumes by commodity type that are expected to settle each year are:

	Electricity Contracts	**Natural Gas Contracts**	**Other Fuel Contracts**
Year to settle	**Financial Mwhs**	**Financial Dths**	**Financial Gals**
As of December 31, 2010			
2011	4,652,994	16,983,245	1,569,200
2012	1,146,240	1,532,202	-
2013	-	10,164	-
As of December 31, 2009			
2010	3,158,334	17,249,762	3,743,000
2011	192,469	1,648,254	-

Notes to Consolidated Financial Statements

The location and amounts of derivative fair values in the balance sheet are:

	Asset Derivatives		Liability Derivatives	
As of December 31,	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
(Thousands)				
Derivatives designated as hedging instruments				
2010				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	$9,829	Current liabilities	$(234)
Long-term	Other assets	400	Other liabilities	(370)
Natural gas derivatives:				
Current	Current assets	-	Current liabilities	(13,117)
Long-term	Other assets	18	Other liabilities	(57)
Other contracts:	Current assets	95	Current liabilities	-
Total		$10,342		$(13,778)
2009				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	$4,383	Current liabilities	$(321)
Long-term	Other assets	431	Other liabilities	(184)
Natural gas derivatives:				
Current	Current assets	129	Current liabilities	(9,271)
Long-term	Other assets	11	Other liabilities	(309)
Other contracts:	Current assets	633	Current liabilities	(16)
Total		$5,587		$(10,101)

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The effect of hedging instruments on OCI and income was:

Year Ended December 31,	Gain (Loss) Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain (Loss) Reclassified from Accumulated OCI into Income	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives
Derivatives in Cash Flow Hedging Relationships	**Effective Portion (1)**	**Effective Portion (1)**		**Ineffective Portion and Amount Excluded from Effectiveness Testing (2)**	
(Thousands)					
2010					
Interest rate contracts	-	Interest expense	$(9,035)	Interest expense	-
Commodity contracts:					
Electricity derivatives	$7,921	Electricity purchased	(11,304)	Other (Income)/ Other Deductions	$(136)
Natural gas	3,390	Natural gas purchased	(3,549)		-
Other	206	Other direct costs	59		-
Total	$11,517		$(23,829)		$(136)
2009					
Interest rate contracts	$(86,359)	Interest expense	$(6,149)	Interest expense	-
Commodity contracts:					
Electricity derivatives	16,946	Electricity purchased	(56,497)	Other (Income)/ Other Deductions	$104
Other	(1,748)	Other direct costs	(3,974)		-
Total	$(71,161)		$(66,620)		$104

(1) Changes in OCI are reported in after-tax dollars.
(2) Ineffective portion of long-term power supply contracts that are designated as cash flow hedges.

The amount in OCI related to previously settled forward starting swaps, after tax and accumulated amortization, as of December 31, 2010, is a net loss of $131.8 million as compared to a net loss of $140.9 million for 2009.

As of December 31, 2010, we reported $20.3 million in net derivative losses related to discontinued cash flow hedges. At December 31, 2010, $8.2 million in gains are reported in OCI because the forecasted transaction is considered to be probable. We expect that $8.0 million of gains in OCI will be reclassified into earnings within the next 12 months.

As of December 31, 2010, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions was 22 months – through October 2012.

NYSEG, RG&E and our unregulated energy marketing subsidiaries Energetix, Inc. and NYSEG Solutions, Inc., face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally

Moody's or S&P). When our exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract. For financial statement presentation, we do not offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement. Under the master netting arrangements our obligation to return cash collateral was $1.5 million at December 31, 2010, and $1.7 million at December 31, 2009.

Certain of our derivative instruments contain provisions that require us to maintain on our debt an investment grade credit rating from each of the major credit rating agencies. If our debt were to fall below investment grade, it would be in violation of those provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2010, is $13.8 million for which we have posted collateral of $22.1 million in the normal course of business. If the credit-risk-related contingent features underlying those agreements were triggered on December 31, 2010, we would receive a refund of $8.3 million of collateral with our counterparties.

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The carrying amounts and estimated fair values of our financial instruments are shown in the following table. Carrying amounts include related debt premiums and discounts.

December 31,	**2010**		**2009**	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
(Thousands)				
First mortgage bonds	**$774,952**	**$836,830**	$1,121,921	$1,180,627
Pollution control notes, fixed	**$367,443**	**$363,084**	$351,811	$350,573
Pollution control notes, variable	**$168,200**	**$146,931**	$256,725	$247,903
Various long-term debt	**$902,258**	**$914,731**	$1,083,081	$1,083,945
Long-term debt owed to affiliates	**$650,000**	**$725,834**	$1,350,000	$1,481,946

The carrying amounts for cash and cash equivalents, accounts receivable, notes payable and interest accrued approximate their estimated fair values.

We value all fixed rate long-term debt, whether unsecured or secured by a first mortgage lien, taxable or tax-exempt, by assigning a market-based yield for each security and then deriving the price from the yield. Market-based yields are determined by observing secondary market trading levels for debt of similar maturity, rating, tax and structural characteristics. We value all variable rate debt at par as it approximates fair value, except for the auction rate securities issued by RG&E, which do not have an active market.

Assets and liabilities measured at fair value on a recurring basis

		Fair Value Measurements at December 31, Using		
Description	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2010				
Assets				
Noncurrent investments available for sale, auction rate securities	$2,700	-	-	$2,700
Noncurrent investments available for sale, other	44,520	$44,520	-	-
Derivatives				
Commodity contracts				
Electricity	10,230	1,431	-	8,799
Natural gas	18	18	-	-
Other	94	-	-	94
Total	$57,562	$45,969	-	$11,593
Liabilities				
Derivatives				
Commodity contracts:				
Electricity	$604	$370	-	$234
Natural gas	13,174	13,174	-	-
Total	$13,778	$13,544	-	$234
2009				
Assets				
Noncurrent investments available for sale, auction rate securities	$2,735	-	-	$2,735
Noncurrent investments available for sale, other	114,706	$114,706	-	-
Derivatives				
Commodity contracts:				
Electricity	4,814	-	-	4,813
Natural gas	140	140	-	-
Other	633	-	-	633
Total	$123,028	$114,846	-	$8,181
Liabilities				
Derivatives				
Commodity contracts:				
Electricity	$505	-	-	$505
Natural gas	9,580	$9,580	-	-
Other	16	-	-	16
Total	$10,101	$9,580	-	$521

We had no significant transfers to or from Level 1 and 2 during the year ended December 31, 2010. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our noncurrent investments available for sale, auction rate securities based on the estimated probabilities of when the auction rate markets would return to historic interest rate levels and include the measurements in Level 3. During 2009 we reassessed the valuation of our investment in accordance with guidance related to decreased market activity. (See Note 1.)

We measure the fair value of our noncurrent investments available for sale, other using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments primarily consist of money market funds, but also include some fixed income and equity investments.

We determine the fair value of our various derivative assets and liabilities utilizing market approach valuation techniques:

- NYSEG, RG&E and our energy marketing subsidiaries enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. Those companies hedge their electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. In December 2009 NYSEG and RG&E began to hedge all of their electric load obligations in a NYISO location where an active market exists. The forward market prices used to value their open electric energy derivative contracts as of December 31, 2010, were readily available with no adjustment required and we include the fair value in Level 1. Our energy marketing subsidiaries, and NYSEG and RG&E for periods prior to December 31, 2009 enter into hedges for some NYISO locations where forward market price quotes are not actively traded and not readily available outright from market dealers. We derived forward market prices for these locations based on the historical relationship of prices in those locations to prices in locations where an active market exists. The resulting value represents the derived forward market price for each location, which we use to value the open derivative contracts. Because we adjust the quoted market prices for our own load characteristics, we include the fair values in Level 3.
- NYSEG, RG&E and our energy marketing subsidiaries enter into natural gas derivative contracts to hedge the forecasted purchases required to serve their natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.

Instruments measured at fair value on a recurring basis using significant unobservable inputs

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Auction Rate Securities	**Derivatives, Net**	**Total**
Balance, January 1, 2009	$3,850	$(130,742)	$(126,892)
Total (losses) gains (realized/unrealized)			
Included in earnings	(1,115)	128,994	127,879
Included in other comprehensive income	-	(91,604)	(91,604)
Included in regulatory liabilities	-	57,089	57,089
Purchases, issuances and settlements	-	41,188	41,188
Transfers into Level 3	-	-	-
Balance, December 31, 2009	2,735	4,925	7,660
Total (losses) gains (realized/unrealized)			
Included in earnings	(35)	20,297	20,262
Included in other comprehensive income	-	(13,700)	(13,700)
Included in regulatory liabilities	-	-	-
Purchases, issuances and settlements	-	(2,863)	(2,863)
Transfers into of Level 3	-	-	-
Balance, December 31, 2010	$2,700	$8,659	$11,359
Total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at December 31,			
2009	-	$90	$90
2010	-	-	-

The gains and losses included in earnings for the period (above), which are reported in the various categories indicated are:

(Thousands)	**Electricity purchased**	**Other operating expense**	**Other Income**	**Other Deductions**	**Interest expense**
Total gains (losses) included in earnings for year ended December 31,					
2009	$103,088	$19,667	$90	$(1,115)	$6,149
2010	$7,956	$3,305	-	(35)	$9,036

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Note 13. Accumulated Other Comprehensive Income (Loss)

(Thousands)	Balance January 1, 2009	2009 Change	Balance December 31, 2009	2010 Change	Balance December 31, 2010
Net unrealized holding (losses) gains on investments, net of income tax (expense) of $(749) for 2009 and $(70) for 2010	$(1,124)	$1,124	-	$(45)	$(45)
Amortization of pension cost for nonqualified plans, net of income tax benefit (expense) of $319 for 2009 and $(769) for 2010	(9,428)	(567)	$(9,995)	1,177	(8,818)
Unrealized gains (losses) on derivatives qualified as hedges:					
Unrealized gains during period on derivatives qualified as hedges, net of income tax (expense) of $(28,529) for 2009 and $(22,638) for 2010		42,631		41,345	
Reclassification adjustment for losses (gains) included in net income, net of income tax (benefit) expense of $(23,969) for 2009 and $24,007 for 2010		36,502		(36,558)	
Net unrecognized (losses) gains on settled cash flow treasury hedges, net of income tax benefit (expenses) of $24,554 for 2009 and $(3,726) for 2010		(36,066)		5,603	
Net unrealized (losses) gains on derivatives qualified as hedges	(129,798)	43,067	(86,731)	10,390	(76,341)
Accumulated Other Comprehensive (Loss) Income	$(140,350)	$43,624	$(96,726)	$11,522	$(85,204)

No Accumulated Other Comprehensive Income (Loss) is attributable to the noncontrolling interests for the above periods.

Notes to Consolidated Financial Statements

Note 14. Retirement Benefits

We have funded noncontributory defined benefit pension plans that cover substantially all of our employees. The plans provide defined benefits based on years of service and final average salary. We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

***Obligations and funded status*:**

	Pension Benefits		Postretirement Benefits	
	2010	**2009**	**2010**	**2009**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$2,333,547**	$2,240,741	**$529,945**	$497,995
Service cost	**34,092**	32,664	**5,299**	5,414
Interest cost	**131,562**	134,325	**27,679**	29,528
Plan participants' contributions	**-**	-	**10,957**	9,424
Curtailments	**1,134**	-	**-**	-
Plan amendments	**10,886**	125	**(21,446)**	-
Special termination benefits	**37,351**	-	**-**	-
Actuarial loss	**166,733**	66,046	**22,442**	29,084
Benefits paid	**(158,769)**	(140,354)	**(49,482)**	(44,534)
Federal subsidy on benefits paid	**-**	-	**3,100**	3,034
Disposition of obligations related to sale of natural gas companies	**(350,116)**	-	**(57,082)**	-
Benefit obligation at December 31	**$2,206,420**	$2,333,547	**$471,412**	$529,945
Change in plan assets				
Fair value of plan assets at January 1	**$2,253,753**	$1,995,905	**$146,309**	$112,433
Actual return on plan assets	**262,786**	396,287	**18,123**	27,094
Employer contributions	**30,430**	1,915	**36,030**	49,913
Plan participants' contributions	**-**	-	**14,057**	1,403
Benefits paid	**(158,769)**	(140,354)	**(49,482)**	(44,534)
Disposition of assets related to sale of natural gas companies	**(237,001)**	-	**(17,039)**	-
Fair value of plan assets at December 31	**$2,151,199**	$2,253,753	**$147,998**	$146,309
Funded status at December 31	**$(55,221)**	$(79,794)	**$(323,414)**	$(383,636)

Amounts recognized in the balance sheet	Pension Benefits		Postretirement Benefits	
December 31,	**2010**	**2009**	**2010**	**2009**
(Thousands)				
Noncurrent assets	**$87,336**	$145,723	**-**	-
Current liabilities	**-**	-	**$(6,545)**	$(6,391)
Noncurrent liabilities	**(142,557)**	(225,517)	**(316,869)**	(377,245)
	$(55,221)	$(79,794)	**$(323,414)**	$(383,636)

The change in benefit obligation and change in plan assets activity above reflect activity and the related decreases in the obligation and assets for the natural gas companies through November 16, 2010 (see Note 2). The amounts shown above for the disposition related to the sale of the natural gas companies were based on a roll forward of expenses, including amortization of gains and losses, for the period through November 16, 2010. Those plans were not remeasured as of the date of sale as the gas companies receive regulatory recovery of net periodic benefit costs through rates. Therefore, the sale of the gas companies did not result in gains or losses that should be recognized in our statement of operations.

A Voluntary Early Retirement Program (VERP) was offered in the electric company plans during 2010, resulting in one-time charges for special termination benefits, and a one-time curtailment loss for CMP's Union Plan. NYSEG extended a retirement supplement, effective July 1, 2010, applicable to union employees who retire after age 59 between July 1, 2010, and June 30, 2015; the supplement was first effective July 1, 2005, and applied to retirements between July 1, 2005, and June 30, 2010. As a result of negotiations, CMP made changes to the retiree medical plan benefits for its union employees that include a cap on its contribution to the postretirement medical plans for employees who retire on or after July 1, 2013.

We have determined that all of our operating companies are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities consist of:

	Pension Benefits		**Postretirement Benefits**	
December 31,	**2010**	**2009**	**2010**	**2009**
(Thousands)				
Net loss	**$812,113**	$943,802	**$47,970**	$50,653
Prior service cost (credit)	**$29,630**	$26,044	**$(19,796)**	$(7,689)
Transition obligation	**-**	-	**$13,600**	$20,400

Our accumulated benefit obligation for all defined benefit pension plans was $2.1 billion at December 31, 2010, and $2.2 billion at December 31, 2009.

CMP's and NYSEG's postretirement benefits were partially funded at December 31, 2010. CMP's, CNG's, NYSEG's and SCG's postretirement benefits were partially funded at December 31, 2009.

The projected benefit obligation exceeded the fair value of pension plan assets for the CMP and RG&E plans as of December 31, 2010; and for the CMP, CNG, SCG, RG&E and Berkshire Gas plans as of December 31, 2009. The accumulated benefit obligation exceeded the fair value of pension plan assets for the CMP plan as of December 31, 2010; and for the CMP, CNG and SCG plans as of December 31, 2009. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for those companies' plans for the relevant periods.

	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		**Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets**	
December 31,	**2010**	**2009**	**2010**	**2009**
(Thousands)				
Projected benefit obligation	**$785,851**	$1,049,408	**$331,295**	$594,083
Accumulated benefit obligation	**$725,962**	$971,240	**$300,039**	$544,709
Fair value of plan assets	**$643,294**	$823,891	**$210,564**	$387,141

***Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities*:**

	Pension Benefits		Postretirement Benefits	
Year ended December 31,	**2010**	**2009**	**2010**	**2009**
(Thousands)				
Net periodic benefit cost				
Service cost	**$34,092**	$32,664	**$5,299**	$5,415
Interest cost	**131,562**	134,325	**27,679**	29,528
Expected return on plan assets	**(216,699)**	(223,979)	**(7,986)**	(6,231)
Amortization of prior service cost (benefit)	**3,507**	4,001	**(9,124)**	(7,152)
Amortization of net loss	**76,910**	48,027	**4,855**	5,925
Special termination benefit charge	**37,351**	-	**-**	-
Curtailment charge	**1,134**	-	**-**	-
Amortization of transition obligation	**-**	-	**6,800**	6,800
Net periodic benefit cost (income)	**$67,857**	$(4,962)	**$27,523**	$34,285
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	**$145,750**	$(106,262)	**$12,305**	$8,221
Prior service cost (benefit)	**2,393**	125	**(21,446)**	-
Amortization of net (loss)	**(76,910)**	(48,027)	**(4,855)**	(5,925)
Current year prior service cost	**7,819**	-	**-**	-
Amortization of prior service (cost) credit	**(3,503)**	(4,001)	**9,124**	7,152
Disposition of obligations related to sale of natural gas companies	**(34,698)**	-	**(7,918)**	-
Amortization of transition obligation	**-**	-	**(6,800)**	(6,800)
Total recognized in regulatory assets and regulatory liabilities	**40,851**	(158,165)	**(19,590)**	2,648
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$108,708**	$(163,127)	**$7,933**	$36,933

Net periodic benefit costs above include amounts related to the gas companies that were sold in 2010	**Pension Benefits**	**Postretirement Benefits**
(Thousands)		
January 1 through November 16, 2010	$10,630	$2,703
Year ended December 31, 2009	$7,346	$3,811

We include the net periodic benefit cost in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents. The amount of postretirement benefit cost deferred at December 31 was $12 million for 2010 and $31 million for 2009. We expect to recover any deferred postretirement costs by 2012. We are amortizing over 20 years the transition obligation for postretirement benefits that resulted from our adoption in 1992 of the accounting requirements concerning employers' accounting for postretirement benefits other than pensions.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2011	**Pension Benefits**	**Postretirement Benefits**
(Thousands)		
Estimated net loss	$82,084	$7,811
Estimated prior service cost	$4,588	$5,962
Estimated transition obligation	-	$6,800

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ended December 31, 2011.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits 2010	Pension Benefits 2009	Postretirement Benefits 2010	Postretirement Benefits 2009
Discount rate	**5.00%**	5.80%	**5.00%**	5.80%
Rate of compensation increase	**4.00%**	4.00%	**4.00%**	4.00%

As of December 31, 2010, we decreased our discount rate from 5.80% to 5.00%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade noncallable bonds that closely matches the duration of the expected cash flows of our benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for year ended December 31,	Pension Benefits 2010	Pension Benefits 2009	Postretirement Benefits 2010	Postretirement Benefits 2009
Discount rate	**5.80%**	6.10%	**5.80%**	6.10%
Expected long-term return on plan assets	**8.75%**	8.75%	**-**	-
Expected long-term return on plan assets - nontaxable trust	**-**	-	**8.00%**	8.00%
Expected long-term return on plan assets - taxable trust	**-**	-	**4.80%**	4.80%
Rate of compensation increase	**4.00%**	4.00%	**4.00%**	4.00%

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. The operating companies amortize unrecognized actuarial gains and losses either over 10 years from the time they are incurred or using the standard amortization methodology, under which amounts in excess of 10% of the greater of the projected benefit obligation or market-related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates to determine benefit obligations at December 31,	2010	2009
Health care cost trend rate assumed for next year	**7.8%**	8.0%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**4.5%**	4.5%
Year that the rate reaches the ultimate trend rate	**2028**	2028

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

(Thousands)	1% Increase	1% Decrease
Effect on total of service and interest cost	$872	$(756)
Effect on postretirement benefit obligation	$11,895	$(11,462)

***Plan assets*: ** Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefits obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

Our asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets of 56% equity securities, 30% fixed income and 14% for all other types of investments. The target allocations within allowable ranges are further diversified into 28% large cap domestic equities, 7% medium and small cap domestic equities, 5% emerging markets, and 16% international equity securities. Fixed income investment targets and ranges are segregated into long dated corporate securities 17%, annuity contracts 5%, and 25 year zero coupon bonds 8%. All fixed income investments are in domestic securities. Other, alternative investment targets are 4% for real estate, and 10% for absolute return and strategic markets. Systematic rebalancing within the target ranges, should any asset categories drift outside their specified ranges, increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

The fair values of our pension benefits plan assets at December 31, 2010 and 2009, by asset category are:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2010				
Cash and cash equivalents	**$49,214**	**$734**	**$48,480**	**-**
U.S. government securities	**52,122**	**52,122**	**-**	**-**
Common stocks	**1,036,468**	**749,565**	**286,903**	**-**
Registered investment companies	**85,923**	**85,923**	**-**	**-**
Corporate bonds	**183,186**	**-**	**183,186**	**-**
Preferred stocks	**7,039**	**7,039**	**-**	**-**
Common/collective trusts	**351,408**	**-**	**76,476**	**$274,932**
Partnership/joint venture interests	**96,624**	**-**	**-**	**96,624**
Real estate investments	**45,374**	**-**	**-**	**45,374**
Other investments, principally annuity and fixed income	**243,841**	**21,817**	**31,712**	**190,312**
Total	**$2,151,199**	**$917,200**	**$626,757**	**$607,242**
2009				
Cash and cash equivalents	$38,248	$927	$37,321	-
U.S. government securities	49,619	49,619	-	-
Common stocks	1,000,311	997,495	2,816	-
Registered investment companies	119,155	119,155	-	-
Corporate bonds	364,243	-	364,243	-
Preferred stocks	6,916	6,916	-	-
Common/collective trusts	358,201	-	62,557	$295,644
Partnership/joint venture interests	93,269	-	-	93,269
Real estate investments	40,618	-	-	40,618
Other investments, principally annuity and fixed income	183,173	20,784	31,265	131,124
Total	$2,253,753	$1,194,896	$498,202	$560,655

Notes to Consolidated Financial Statements

Valuation techniques: We value our pension benefits plan assets as follows:

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities, Common stocks and Registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common/collective trusts and Partnership/joint ventures – using the Net Asset Value (NAV) provided by the administrator of the fund. The NAV is based on the value of the underlying assets owned by the fund, minus its liabilities, and then divided by the number of shares outstanding. The NAV is classified as Level 2 if the plan has the ability to redeem the investment with the investee at NAV per share at the measurement date. Redemption restrictions or adjustments to NAV based on unobservable inputs result in the fair value measurement being classified as Level 3 if those inputs are significant to the overall fair value measurement.
- Real estate investments – based on a discounted cash flow approach that includes the projected future rental receipts, expenses and residual values because the highest and best use of the real estate from a market participant view is as rental property.
- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)					
(Thousands)	**Corporate Bonds**	**Common/ Collective Trusts**	**Partner- ship/ Joint Venture Interests**	**Real Estate Invest- ments**	**Other Invest- ments**	**Total**
Balance, December 31, 2008	$112	$432,918	$106,819	$58,687	$156,149	$754,685
Actual return on plan assets:						
Relating to assets still held at the reporting date	-	2,557	2,565	-	-	5,122
Relating to assets sold during the year	-	112,364	3,869	(19,345)	-	96,888
Purchases, sales and settlements	(112)	(252,195)	(19,984)	1,276	(25,025)	(296,040)
Transfers into and/or out of Level 3	-	-	-	-		
Balance, December 31, 2009	-	295,644	93,269	40,618	131,124	560,655
Actual return on plan assets:						
Relating to assets still held at the reporting date	-	4,678	-	-	110	4,788
Relating to assets sold during the year	-	41,218	3,207	4,163	510	49,098
Purchases, sales and settlements	-	(66,608)	148	593	58,568	(7,299)
Transfers into and/or out of Level 3	-	-	-	-	-	-
Balance, December 31, 2010	-	$274,932	$96,624	$45,374	$190,312	$607,242

Notes to Consolidated Financial Statements

Our postretirement benefits plan assets are held with two trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes in order to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 12% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes. The remainder is invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for our postretirement benefits plan assets of 56% equity securities, 37% fixed income and 7% for all other types of investments. The target allocations within allowable ranges are further diversified into 30% large cap domestic equities, 7% medium and small cap domestic equities, 13% international developed market and 6% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 30%, global high yield fixed income 4% and international developed market debt 3%. Other, alternative investment targets are 4% for real estate and 3% absolute return. Systematic rebalancing within target ranges, should any asset categories drift outside their specified ranges, increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

The fair values of our other postretirement benefits plan assets at December 31, 2010 and 2009, by asset category are:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2010				
Money market funds	**$7,907**	**$7,907**	**-**	**-**
Mutual funds, fixed	**49,100**	**49,100**	**-**	**-**
Mutual funds, equity	**90,964**	**90,964**	**-**	**-**
Other investments	**27**	**27**	**-**	**-**
Total assets measured at fair value	**$147,998**	**$147,998**	**-**	**-**
2009				
Money market funds	$4,214	$4,214	-	-
Mutual funds, fixed	51,061	51,061	-	-
Mutual funds, equity	82,089	82,089	-	-
Other investments	3,109	1,865	$774	$470
Total assets measured at fair value	$140,473	$139,229	$774	$470
Whole life insurance contract	5,836			
Total postretirement benefits plan assets	$146,309			

Valuation techniques: We value our postretirement benefits plan assets as follows:

- Money market funds and Mutual funds, fixed and equity – based upon quoted market prices, which represent the NAV of the shares held.
- Other investments – these are primarily 401(h) investments that are an allocation of pension Master Trust investments.

The whole life insurance contract is presented at the contract value at December 31, 2009, which is not a fair value measurement.

Diversified equity securities did not include any Iberdrola common stock at December 31, 2010.

Cash Flows

***Contributions*:** In accordance with our funding policy we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $38 million to our pension benefit plans and $3 million to our other postretirement benefit plans in 2011.

***Estimated future benefit payments*:** Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2011	$145,440	$39,538	$3,069
2012	$147,689	$40,136	$3,615
2013	$151,763	$40,672	$3,933
2014	$154,565	$41,258	$4,234
2015	$156,662	$41,552	$4,512
2016 - 2020	$795,935	$206,194	$26,406

Note 15. NYSEG and RG&E Rate Proceedings

In September 2009 NYSEG and RG&E filed rate cases with the NYPSC requesting approval to increase the rates the companies charge to deliver electricity and natural gas by a total of $383 million. The rate filings requested an allowed rate of return on equity (ROE) of 11.43% applied to an equity ratio of 48%.

On September 16, 2010, the NYPSC approved a new rate plan for electric and natural gas service provided by the companies effective August 26, 2010, through December 31, 2013. Major provisions of the plan include:

- Approximate delivery rate increases as follows (in millions of dollars):

Rate year ending August 31,	NYSEG Electric	NYSEG Natural Gas	RG&E Electric	RG&E Natural Gas
2011	$16.4 (2.5%)	$9.9 (6.0%)	$15.6 (4.1%)	$10.9 (8.0%)
2012	$27.8 (4.2%)	$10.3 (5.8%)	$10.2 (2.6%)	$10.9 (7.3%)
2013	$29.3 (4.3%)	$10.5 (5.6%)	$13.2 (3.2%)	$11.0 (6.9%)

- The delivery rate increases were moderated and levelized through the use of $311 million in positive benefits adjustments (PBAs), including $36 million of carrying costs, that were required and set aside for the benefit of ratepayers when Iberdrola, S.A. acquired NYSEG and RG&E in 2008. The PBAs will be utilized as follows: in September 2010 a one-time write-off of $82.5 million, which is offset by write-offs of deferred storm costs of $76.4 million, $6.1 million in property tax and amortizations during the rate years ended August 31 of: $88.0 million in 2011, $54.4 million in 2012 and $26.9 million in 2013; and $8.5 million in the four months ended December 31, 2013. The balance of $50.2 million will be amortized at a later time.
- Rates were set to allow for the recovery, over the 40 months of the rate plan, of regulatory assets of $126.0 million net of regulatory liabilities.

- The recovery includes $32.4 million for the cost to achieve efficiency initiatives through workforce reductions (see Note 1). The rate increases were moderated with $19.2 million in annual net savings from workforce reduction and related labor cost-cutting initiatives, as well as a one percent annual productivity adjustment.
- To resolve a number of disputed items related to the annual compliance filings, including the calculation of earnings sharing accruals, NYSEG reduced its environmental reserve by $23 million and its deferred storm costs by $4 million, and added $6 million to the Asset Sale Gain Account (ASGA). RG&E absorbed $20 million of prior loss from interest rate hedges and added $6.5 million to the ASGA. In December 2009 NYSEG established a reserve of $30 million and RG&E established a reserve of $10 million for those contingencies, which were reversed as a result of the rate decision.
- The revenue requirements are based on a 10% allowed ROE applied to an equity ratio of 48 percent. Beginning in 2011, if earnings exceed the allowed return, a tiered earnings sharing mechanism (ESM) will capture a portion of the excess for the benefit of ratepayers. The ESM is subject to specified downward adjustments if the companies fail to meet certain reliability and customer service measures.
- Key components of the rate plan include electric reliability performance mechanisms, natural gas safety performance measures, customer service quality metrics and targets, and electric distribution vegetation management programs that establish threshold performance targets. There will be downward revenue adjustments if the companies fail to meet the targets.
- Low-income program budgets have been increased to approximately $19.2 million. All home energy assistance program recipients will be eligible for the program.
- New revenue decoupling mechanisms (RDMs), intended to remove company disincentives to promote increased energy efficiency were established. Under the RDMs, electric revenues are based on revenue per customer class rather than billed revenue, while natural gas revenues are based on revenue per customer. Any shortfalls (excesses) between billed revenues and allowed revenues will be accrued for future recovery (refund).

Under the merger order prescribed by the NYPSC, NYSEG and RG&E customers were to receive $275 million in PBAs. Those benefits were to be used, over time, to either reduce rates or moderate requested rate increases. Conditions were also established to ensure that ratepayers receive a portion of any added benefits associated with synergy savings and efficiency gains produced by the transaction. We recorded the PBAs in September 2008, in accordance with the merger order, as a regulatory liability with an offsetting charge to income, and accrued a carrying cost at the pretax rate allowed by the NYPSC until used for the benefit of customers. Carrying costs, which are included in interest expense, were $13 million in 2010 and $18 million in 2009.

As part of the new rate plan, the companies offset the PBAs and other regulatory liabilities against certain regulatory assets. In addition, the companies established a regulatory asset to allow recovery of the special termination benefits and severance costs associated with workforce reductions (see Note 1), and wrote off some undepreciated fixed assets and reversed a reserve established in December 2009. The effects on net income of the various adjustments to regulatory assets and regulatory liabilities are:

Description	Income Statement Line Item	Increase (Decrease) in Net Income
(Millions)		
Elimination of annual compliance filing reserve regulatory liability	Electric operating revenue	$40.0
ASGA	Electric operating revenue	(6.5)
Interim period adjustment	Electric operating revenue	2.8
	Total Electric Operating Revenue	36.3
Elimination of PBA regulatory liability	Other operating expenses	82.4
Elimination of storm costs regulatory assets	Maintenance	(81.4)
Elimination of environmental reserve regulatory asset	Other operating expenses	(23.0)
Establishment of cost to achieve efficiency regulatory asset*	Other operating expenses	32.9
Elimination of property taxes	Other taxes	(5.1)
	Net effects of new rate case on operating and maintenance	5.8
Property, plant and equipment	Depreciation and amortization	(10.8)
	Total Operating Expenses	(5.0)
	Income Before Income Taxes	31.3
Income tax effect	Income Taxes	(12.4)
	Net Income	$18.9

*Relates to the recovery of special termination benefit costs (see Note 1).

Beginning on August 26, 2010, NYSEG will amortize $15.2 million per year of a theoretical excess depreciation reserve of $303.9 million; and beginning on September 1, 2012, RG&E will amortize $5.25 million per year of its theoretical excess depreciation reserve of $105 million. Both amortization amounts reflect a 20-year amortization period. Theoretical excess depreciation is the difference between actual accumulated depreciation taken to date and a theoretical reserve. The actual accumulated depreciation is the result of depreciation rates allowed in prior rate orders based on estimates of useful lives and net salvage values as determined in those cases. The theoretical reserve is the amount that would have accumulated if the depreciation rates in the new rate plan had been in place for the entire useful lives of the affected assets. Differences between the actual reserve and the theoretical reserve are normal aspects of utility ratemaking. The usual treatment is to flow any excess or deficiency back as an adjustment to depreciation expense over the remaining life of the property. However, in accordance with the new rate plan, NYSEG and RG&E will moderate electric rates by recording the theoretical reserve amortization as a debit to accumulated depreciation and a credit to other revenues, and normalize the amortization from a tax perspective.

Note 16. Sale of NYSEG's Seneca Lake Storage Facility

In January 2010 NYSEG entered into an agreement to sell its Seneca Lake Storage facility and related assets for $65 million. The carrying amount of the facility assets is separately stated on the balance sheet and was approximately $33 million at December 31, 2010, and December 31, 2009. The sale of the facility is contingent on receiving appropriate regulatory approvals from the NYPSC. The FERC issued an order on August 26, 2010, authorizing the parties to proceed with the transaction, subject to compliance requirements that the buyer must attend to but that should not delay the closing. NYSEG is unable to predict at this time when final approval for the transaction will be obtained, or when the closing will occur. Because current rates include recovery of depreciation on these assets, we are continuing to record depreciation expense even though we have classified the assets as held for sale. Depreciation expense for 2010 was $1.5 million.

Note 17. Sale of Fossil Fuel Generation Assets

Iberdrola, in connection with receiving authorization from the NYPSC in September 2008 to acquire Energy East, agreed to sell certain fossil fuel generation assets owned by either RG&E or Cayuga Energy, Inc. (Cayuga). In its order authorizing the acquisition, the NYPSC directed Iberdrola and the other petitioners in the acquisition proceeding to develop, in collaboration with interested parties, a divestiture plan for the fossil fuel generation assets. Iberdrola and Energy East filed the divestiture plan with the NYPSC in November 2008. The NYPSC issued an order approving the divestiture plan as filed, effective November 17, 2009.

The divestiture plan required the generation assets to be sold at auction in a two-stage process, as well as extensive consultation with the NYPSC Staff concerning the auction process. The auction process would be suspended, but not terminated, if bids obtained were priced at less than the current net book value of the assets (approximately $14 million at December 31, 2009). Iberdrola/RG&E would then petition the NYPSC for guidance on the next steps to be taken. On December 29, 2010, we filed a petition with the NYPSC for permission to terminate the auction process.

As a result of the unsuccessful auction process we performed an impairment test of all long-lived assets not included in regulated rates. We determined that no impairment of long-lived assets had occurred.

We have determined that the criteria are not met in order to classify the assets as held for sale. In addition, the net book value of the assets is immaterial to our balance sheet.

Iberdrola USA, Inc.
Consolidated Financial Statements
For the Years Ended December 31, 2011 and 2010

Iberdrola USA, Inc.

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Management's Report on Internal Control Over Financial Reporting

Iberdrola USA, Inc.'s (the company) internal control over financial reporting is a process affected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. An entity'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 entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and those charged with governance; and (3) provide reasonable assurance regarding prevention, or timely detection and correction of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Management is responsible for establishing and maintaining effective internal control over financial reporting. Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2011, based on the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework*. Based on that assessment, management concluded that, as of December 31, 2011, the company's internal control over financial reporting is effective based on the criteria established in *Internal Control—Integrated Framework*. The effectiveness of the company's internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent public accounting firm, as stated in their report which appears herein.

Iberdrola USA, Inc.
February 10, 2012

Report of Independent Auditors

To the Stockholder and Board of Directors of Iberdrola USA, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income, of cash flows and of changes in equity present fairly, in all material respects, the financial position of Iberdrola USA, Inc. and its subsidiaries (collectively, the "Company") at December 31, 2011 and 2010, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assertion of the effectiveness of internal control over financial reporting, included in *Management's Report on Internal Control Over Financial Reporting* dated February 10, 2012, listed in the accompanying Index to the Iberdrola USA, Inc. Consolidated Financial Statements for the Years Ended December 31, 2011 and 2010. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits of the financial statements in accordance with auditing standards generally accepted in the United States of America and our audit of internal control over financial reporting in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 to the consolidated financial statements, the Company sold three of their natural gas holding company subsidiaries and their natural gas distribution utilities on November 16, 2010.

A company's internal control over financial reporting is a process effected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 those charged with governance; and (iii) provide reasonable assurance regarding prevention, or timely detection and correction of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent, or detect and correct 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.

PricewaterhouseCoopers LLP

February 10, 2012

Iberdrola USA, Inc.
Consolidated Statements of Operations

Year ended December 31,	2011	2010
(Thousands)		
Operating Revenues		
Utility	**$3,269,299**	$3,262,847
Other	**378,237**	400,080
Total Operating Revenues	**3,647,536**	3,662,927
Operating Expenses		
Electricity purchased and fuel used in generation		
Utility	**882,706**	958,277
Other	**244,212**	277,867
Natural gas purchased		
Utility	**331,330**	351,207
Other	**46,953**	56,664
Other operating expenses	**831,092**	726,561
Maintenance	**260,869**	285,355
Depreciation and amortization	**226,301**	239,160
Other taxes	**259,791**	235,715
Total Operating Expenses	**3,083,254**	3,130,806
Operating Income	**564,282**	532,121
Other (Income)	**(49,769)**	(31,579)
Other Deductions	**62,388**	196,058
Interest Charges, Net	**221,882**	259,813
Income From Continuing Operations Before Income Taxes	**329,781**	107,829
Income Taxes Expenses (Benefits)	**50,442**	(24,124)
Income From Continuing Operations	**279,339**	131,953
Discontinued Operations		
(Loss) from discontinued operations (including loss on sale of natural gas companies of $364,046 in 2010)	**(11,083)**	(296,716)
Income taxes (benefits) expenses (including taxes on sale of $18,300 in 2010)	**(14,923)**	42,181
Income (Loss) From Discontinued Operations	**3,840**	(338,897)
Net Income (Loss)	**283,179**	(206,944)
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	**528**	785
Net Income Attributable to Other Noncontrolling Interests	**1,439**	1,615
Net Income (Loss) Attributable to Iberdrola USA	**$281,212**	$(209,344)

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

Iberdrola USA, Inc.
Consolidated Statements of Comprehensive Income

Year ended December 31,	2011	2010
(Thousands)		
Net Income (Loss)	**$283,179**	$(206,944)
Other Comprehensive (Loss) Income, Net of Tax	**(8,855)**	11,522
Comprehensive Income (Loss)	**274,324**	(195,422)
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	**528**	785
Comprehensive Income Attributable to Other Noncontrolling Interests	**1,439**	1,615
Comprehensive Income (Loss) Attributable to Iberdrola USA	**$272,357**	$(197,822)

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

Iberdrola USA, Inc.
Consolidated Balance Sheets

December 31, (Thousands)	2011	2010
Assets		
Current Assets		
Cash and cash equivalents	**$65,862**	$75,688
Accounts receivable and unbilled revenues, net	**612,619**	641,779
Fuel and natural gas in storage, at average cost	**78,741**	80,515
Materials and supplies, at average cost	**35,898**	31,483
Deferred income taxes	**74,189**	62,081
Derivative assets	**-**	9,924
Prepaid income taxes	**9,813**	168,600
Broker margin accounts	**32,043**	22,076
Prepayments and other current assets	**100,852**	97,970
Total Current Assets	**1,010,017**	1,190,116
Utility Plant, at Original Cost		
Electric	**6,817,975**	6,419,555
Natural gas	**1,481,997**	1,423,381
Common	**567,218**	539,260
	8,867,190	8,382,196
Less accumulated depreciation	**3,167,250**	3,029,712
Net Utility Plant in Service	**5,699,940**	5,352,484
Construction work in progress	**849,095**	496,319
Total Utility Plant	**6,549,035**	5,848,803
Assets Held For Sale	**-**	32,730
Other Property and Investments		
Other property and investments	**139,043**	150,702
Tax equity investments	**420,856**	478,016
Total Other Property and Investments	**559,899**	628,718
Regulatory and Other Assets		
Regulatory assets		
Nuclear plant obligations	**50,256**	75,896
Unfunded future income taxes	**433,366**	453,145
Environmental remediation costs	**175,312**	237,026
Unamortized loss on debt reacquisitions	**37,473**	44,667
Nonutility generator termination agreements	**23,524**	35,286
Natural gas hedges	**36,435**	12,802
Pension and other postretirement benefits	**1,105,474**	886,224
Other	**364,841**	291,181
Total regulatory assets	**2,226,681**	2,036,227
Other assets		
Goodwill	**983,646**	983,646
Prepaid pension benefits	**-**	87,336
Derivative assets	**158**	418
Other	**71,706**	66,082
Total other assets	**1,055,510**	1,137,482
Total Regulatory and Other Assets	**3,282,191**	3,173,709
Total Assets	**$11,401,142**	$10,874,076

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

Iberdrola USA, Inc.
Consolidated Balance Sheets

December 31,	2011	2010
(Thousands, except shares)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	**$155,637**	$89,055
Notes payable	**74,800**	142,400
Accounts payable and accrued liabilities	**479,245**	265,445
Accounts payable, electricity purchased	**62,936**	108,560
Accounts payable, natural gas purchased	**25,356**	99,341
Interest accrued	**30,550**	26,003
Interest accrued on debt to affiliates	**7,568**	7,503
Taxes accrued	**46,037**	195,244
Derivative liabilities	**40,237**	13,351
Environmental remediation costs	**50,258**	49,044
Other	**221,855**	225,066
Total Current Liabilities	**1,194,479**	1,221,012
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligations	**712,378**	728,407
Deferred income taxes	**486,507**	368,564
Gain on sale of generation assets	**44,945**	47,196
Pension benefits	**14,750**	22,845
Positive benefit adjustments	**124,416**	200,339
Other	**194,799**	167,599
Total regulatory liabilities	**1,577,795**	1,534,950
Other liabilities		
Deferred income taxes	**1,200,935**	1,218,120
Nuclear plant obligations	**135,473**	143,104
Pension and other postretirement benefits	**629,266**	457,711
Environmental remediation costs	**146,775**	158,717
Derivative liabilities	**8,346**	427
Other	**186,225**	185,587
Total other liabilities	**2,307,020**	2,163,666
Total Regulatory and Other Liabilities	**3,884,815**	3,698,616
Long-term Debt		
Other long-term debt	**2,232,998**	2,139,334
Long-term debt owed to affiliates	**650,000**	650,000
Total Long-term Debt	**2,882,998**	2,789,334
Total Liabilities	**7,962,292**	7,708,962
Commitments and Contingencies		
Preferred Stock of Subsidiaries		
Redeemable preferred stock, noncontrolling interests	**12,464**	12,464
Iberdrola USA Common Stock Equity		
Common stock ($.01 par value, 100 shares authorized and outstanding at December 31, 2011 and 2010)	**-**	-
Capital in excess of par value	**2,009,101**	2,009,101
Retained earnings	**1,496,229**	1,215,017
Accumulated other comprehensive loss	**(94,059)**	(85,204)
Total Iberdrola USA Common Stock Equity	**3,411,271**	3,138,914
Other Noncontrolling Interests	**15,115**	13,736
Total Equity	**3,426,386**	3,152,650
Total Liabilities and Equity	**$11,401,142**	$10,874,076

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

Iberdrola USA, Inc.
Consolidated Statements of Cash Flows

Year Ended December 31,	**2011**	**2010**
(Thousands)		
Operating Activities		
Net income (loss)	**$283,179**	$(206,944)
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**228,395**	283,962
Amortization of regulatory and other assets and liabilities	**44,751**	104,106
Gain on sale of Seneca Lake Storage facility	**(12,397)**	-
Loss on sale of natural gas companies	**-**	88,243
Deferred income taxes and investment tax credits, net	**78,056**	(9,649)
Goodwill Impairment	**-**	275,802
Pension expense	**38,718**	67,857
Positive benefit adjustments including carrying costs	**(75,923)**	(97,599)
Changes in current operating assets and liabilities		
Accounts receivable and unbilled revenues, net	**29,160**	37,717
Broker margin accounts	**(9,967)**	(6,693)
Inventory	**(2,641)**	10,898
Prepaid income taxes	**69,694**	(39,377)
Prepayments and other current assets	**(865)**	(126,190)
Accounts payable and accrued liabilities	**(57,164)**	85,144
Interest accrued on debt to affiliates	**65**	(11,613)
Interest accrued	**4,547**	(5,026)
Taxes accrued	**(11,466)**	215,568
Other current liabilities	**(4,874)**	4,919
Pension and other postretirement benefits contributions	**(32,577)**	(33,430)
VEBA withdrawal	**33,813**	-
Changes in other assets		
Deferred storm costs	**(84,926)**	49,265
Other assets	**(1,847)**	540
Changes in other liabilities		
Environmental remediation costs	**39,542**	9,757
Other liabilities	**42,188**	(1,556)
Net Cash Provided by Operating Activities	**597,461**	695,701
Investing Activities		
Utility plant additions	**(822,409)**	(592,842)
Grants received from governmental entities	**47,755**	24,768
Proceeds from sale of natural gas companies	**-**	917,929
Proceeds from sale of Seneca Lake Storage facility	**65,000**	-
Other property additions	**-**	(559)
Other property sold	**4,814**	7,276
Notes receivable from affiliate	**-**	(550,000)
Repayment of notes receivable from affiliate	**-**	550,000
Tax equity investments	**-**	(236,000)
Investments available for sale	**5,518**	54,434
Net Cash (Used in) Provided by Investing Activities	**(699,322)**	175,006
Financing Activities		
Repayment of preferred stock of subsidiaries, including net premiums	**-**	(11,253)
Long-term note repayments, debt owed to affiliates	**-**	(700,000)
Long-term note issuances	**275,000**	-
Long-term note repayments	**(114,777)**	(222,991)
Notes payable three months or less, net	**(67,600)**	28,094
Dividends to other noncontrolling interests	**(60)**	(1,588)
Dividends paid on preferred stock of subsidiaries, noncontrolling interests	**(528)**	(785)
Net Cash Provided by (Used in) Financing Activities	**92,035**	(908,523)
Net Decrease in Cash and Cash Equivalents	**(9,826)**	(37,816)
Cash and Cash Equivalents, Beginning of Year	**75,688**	113,504
Cash and Cash Equivalents, End of Year	**$65,862**	$75,688

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

Iberdrola USA, Inc.
Consolidated Statements of Changes in Equity

(Thousands, except per share amounts)	Iberdrola USA Shareholder: Common Stock Outstanding $.01 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Other Noncontrolling Interests	Compre-hensive (Loss) Income*	Total
Balance, January 1, 2010	-	-	$2,009,101	$1,424,361	$(96,726)	$15,323		$3,352,059
Net (loss) income*				(209,344)		1,615	$(207,729)	(207,729)
Other comprehensive income, net of tax					11,522		11,522	11,522
Comprehensive (loss)*							$(196,207)	(196,207)
Dividends to other noncontrolling interests						(3,202)		(3,202)
Balance, December 31, 2010	-	-	2,009,101	1,215,017	(85,204)	13,736		3,152,650
Net income*				281,212		1,439	$282,651	282,651
Other comprehensive (loss), net of tax					(8,855)		(8,855)	(8,855)
Comprehensive income*							$273,796	273,796
Dividends to other noncontrolling interests						(60)		(60)
Balance, December 31, 2011	-	-	$2,009,101	$1,496,229	$(94,059)	$15,115		$3,426,386

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

*Amounts do not include Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests of $785 for 2010 and $528 for 2011.

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background: Iberdrola USA, Inc. (Iberdrola USA, the company, we, our, us) is a public utility holding company operating under the Public Utility Holding Company Act of 2005. Iberdrola USA is a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain. We are a super-regional energy services and delivery company with operations in New York, Maine, Connecticut and New Hampshire. Our wholly-owned subsidiaries, and their principal operating utilities, include: CMP Group, Inc. – Central Maine Power Company (CMP), and RGS Energy Group, Inc. – New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E).

We have evaluated events or transactions that occurred after December 31, 2011, for inclusion in these financial statements through February 10, 2012, which is the date these financial statements were available to be issued.

On November 16, 2010, after receiving all regulatory approvals, we sold three of our natural gas holding company subsidiaries and their natural gas distribution utilities to UIL Holdings Corporation (UIL). The three holding companies and their related natural gas distribution utilities are: CTG Resources, Inc. (CTG) and Connecticut Natural Gas Corporation (CNG); Connecticut Energy Corporation (CEC) and The Southern Connecticut Gas Company (SCG); and Berkshire Energy Resources (BER) and The Berkshire Gas Company (BGC). (See Note 2.)

As part of an effort to reduce costs and increase efficiency, we undertook various measures to reduce workforce levels in 2010. We reduced workforce levels by 140 through an involuntary separation at a cost of approximately $3 million, which we paid in cash and charged to other operating expenses. We also offered voluntary early retirement programs (VERPs) to qualifying nonunion and union employees. The 525 employees who accepted the VERPs will receive forms of enhanced pension benefits. In addition, we offered a voluntary severance program (VSP) to certain employees, resulting in a reduction of 36 employees. In 2010 we recorded costs totaling approximately $38 million for the VERPs, which will be paid from our companies' pension plans, and approximately $1 million for the VSP. As part of the New York rate order (see Note 15), we were allowed to recover and defer $32 million of these costs in rates.

In August 2011 RG&E offered a voluntary early retirement program (VERP) to qualifying union employees. The 27 employees who accepted the VERP will receive forms of enhanced pension benefits. In 2011 we recorded costs totaling approximately $1.4 million for the VERP, which will be paid from RG&E's pension plan.

***Accounts receivable*:** Accounts receivable at December 31 include unbilled revenues of $131 million for 2011 and $167 million for 2010, and are shown net of an allowance for doubtful accounts at December 31 of $49 million for 2011 and $40 million for 2010. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $37 million in 2011 and 2010.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and delivery loss factors. Changes in those assumptions could significantly affect the estimates of unbilled revenues.

The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience for each service region and operating segment. Each month the operating companies review their allowance for doubtful accounts and past due accounts over 90 days and/or above a specified amount, and review all other balances on a pooled basis by age and type of receivable. When an operating company believes that a receivable will not be recovered, it charges off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates. During 2010 we recorded an increase in the allowance for doubtful accounts of $7 million because we no longer consider customer security deposits when we determine the amount of our allowance for doubtful accounts.

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer of CMP, NYSEG or RG&E becomes delinquent in making payments, the companies' state regulatory commissions require them to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended time by negotiating mutually acceptable payment terms. Generally, the utility company must continue to serve a customer who cannot pay an account balance in full if the customer: pays a reasonable portion of the balance; agrees to pay the balance in installments; and agrees to pay future bills within 30 days until the DPA is paid in full. DPA receivable balances, net of the applicable reserve, at December 31 were: $66 million for 2011 and 2010.

***Asset retirement obligations*:** We record the fair value of the liability for an asset retirement obligation (ARO) and/or a conditional ARO in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability to its present value periodically over time, and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. Our regulated utilities defer any timing differences between rate recovery and depreciation expense as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

Our ARO at December 31, including our conditional ARO, was $34 million for 2011 and 2010. The ARO primarily consists of obligations related to removal or retirement of: asbestos, PCB-contaminated equipment, gas pipeline and cast iron gas mains. The long-lived assets associated with our AROs are generation property, gas storage property, distribution property and other property.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2011 and 2010.

Year ended December 31,	**2011**	**2010**
(Thousands)		
ARO, beginning of year	**$33,678**	$50,953
Liabilities settled during the year	**(1,273)**	(2,500)
Accretion expense	**2,169**	3,016
Revisions in estimated cash flows	**(374)**	(219)
Disposition of liabilities related to sale of natural gas companies	**-**	(17,572)
ARO, end of year	**$34,200**	$33,678

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

Accrued removal obligations: Our regulated utilities meet the requirements concerning accounting for regulated operations, and recognize a regulatory liability, for financial reporting purposes only, for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Consolidated statements of cash flows**:** We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and those investments are included in cash and cash equivalents.

Supplemental Disclosure of Cash Flows Information	**2011**	**2010**
(Thousands)		
Cash paid (received) during the year ended December 31:		
Interest, net of amounts capitalized	**$169,127**	$257,798
Income taxes, net of cash paid	**$(26,306)**	$(68,103)

Interest capitalized was $7.5 million in 2011 and $3 million in 2010. We have decreased utility plant additions by $151 million for amounts payable as of December 31, 2011 and $87 million in December 31, 2010.

Preliminary survey costs**:** Consolidated preliminary survey costs included in Other assets at December 31 totaled approximately $13 million for 2011 and $11 million for 2010. Preliminary survey costs represent expenditures incurred for the purpose of determining the feasibility of utility projects under contemplation. When construction begins on such projects, the amounts are moved to Construction work in progress, and then eventually to Utility plant when construction is completed and the asset is placed in service. If a project is abandoned, the costs incurred for that project are charged to an appropriate expense account.

Depreciation and amortization**:** We determine depreciation expense substantially using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal, in service at each operating company. The weighted-average service lives of certain classifications of property are: transmission property - 55 years, distribution property - 54 years, generation property - 57 years and other property - 36 years. Our depreciation accruals were equivalent to 2.6% of average depreciable property for 2011 and 2.7% for 2010.

We charge repairs and minor replacements to operating expense, and capitalize renewals and betterments, including certain indirect costs. We charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation.

Goodwill**:** We are required to perform an annual goodwill impairment test at the same time each year and, accordingly, we perform our annual impairment testing of goodwill during the third quarter of each year. We update the test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. The analysis of a potential impairment of goodwill requires a two step process. Step one of the impairment test involves comparing the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of goodwill impairment loss. If the carrying amount is less than fair value, further testing for goodwill impairment is not performed.

Step two of the goodwill impairment test involves comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. In step two, determining the implied fair value of goodwill requires the valuation of a reporting unit's identifiable tangible and intangible assets and liabilities as if the reporting unit had been acquired in a business combination on the testing date. The difference between the fair value of the entire reporting unit as determined in step one and the net fair value of all identifiable assets and liabilities represents the implied fair value of goodwill. A goodwill impairment charge, if any, would be the difference between the carrying amount of goodwill and the implied fair value of goodwill upon the completion of step two.

In performing our annual goodwill impairment test, for purposes of the step one analysis, we base the determination of the fair value of our reporting units on the income approach, which estimates fair value based on discounted future cash flows. Based on the completion of step one of our annual impairment analysis, management determined that the fair value of each reporting unit was greater than its carrying value.

We may be required to recognize an impairment of goodwill in the future due to market conditions or other factors related to our performance. Those market events could include a decline in the forecasted results in our business plan, significant adverse rate case results, changes in capital investment budgets or changes in interest rates that could permanently impair the fair value of a reporting unit. Recognition of impairments of a significant portion of goodwill would negatively affect our reported results of operations and total capitalization, the effect of which could be material and could make it more difficult to maintain our credit ratings, secure financing on attractive terms, maintain compliance with debt covenants and meet expectations of our regulators.

As a result of our decision in May 2010 to sell the natural gas companies we updated our impairment test of the goodwill for SCG, CNG and BGC in accordance with the two step process described above. We determined that the carrying value of the combined companies exceeded the purchase price agreed to by UIL, resulting in a goodwill impairment of $275.8 million. (See Note 3.)

Government grants: Authoritative accounting principles generally accepted in the United States of America do not address accounting for government grants. For that reason, we account for government grants related to depreciable assets in accordance with the prescribed Federal Energy Regulatory Commission (FERC) accounting for contributions in aid of construction, that is, the grant amount is credited to the cost of the related property, plant and equipment. In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as compensation for expenses already incurred in profit or loss in the period in which the expenses are incurred. (See Note 9.)

New accounting standards adopted: We have adopted new accounting standards issued by the Financial Accounting Standards Board (FASB) as explained below.

Credit Quality of Financing Receivables and the Allowance for Credit Losses: A FASB update issued in July 2010 significantly expands existing disclosure requirements concerning credit quality of financing receivables and the allowance for credit losses in order to provide greater transparency about an entity's exposure to credit losses from "lending" type arrangements. Financing receivables include, but are not limited to accounts receivable (with terms exceeding one year), notes receivable, and receivables relating to lessors' rights to payments from leases other than operating leases. The amendments do not apply to short-term trade accounts receivable or receivables measured at fair value or lower of cost or fair value. The objectives for the amendments are to provide information to help users of financial statements understand the nature of credit risk in a company's financing receivables, how that risk is analyzed in determining the related allowance for credit losses, and changes to the allowance during the reporting period. The new disclosures are required for a number of financing arrangements and are expected to affect most entities. The effect for many commercial and industrial entities is expected to be less significant than for traditional banking-type institutions. For nonpublic entities the disclosures are effective for annual reporting periods ending on or after December 15, 2011. Comparative disclosures for earlier reporting periods that ended prior to initial adoption are encouraged but not required and are required for periods after adoption. Our adoption of the amendments did not affect our results of operation, financial position or cash flows.

New accounting standards issued but not yet adopted: New accounting standards issued by the FASB that we have not yet adopted in these financial statements are as explained below.

Disclosures about Offsetting Assets and Liabilities: In December 2011 the FASB amended the requirements concerning disclosures about offsetting assets and liabilities. The amendments do not change the FASB's current offsetting model but will require enhanced disclosures and provide for converged FASB and International Accounting Standards Board disclosures about financial instruments and derivative instruments that are either offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement. The disclosures are meant to enable users of entity's financial statements to understand the effect of offsetting and related arrangements on the entity's financial position. Entities are required to provide both net and gross information about assets and liabilities so as to enhance comparability between entities that prepare their financial statements either based on US GAAP or based on International Financial Reporting Standards (IFRS). The amendments are effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The disclosures required by the amendments are to be provided retrospectively for all comparative periods presented. Our adoption of the amendments will not affect our results of operation, financial position or cash flows.

Testing Goodwill for Impairment: In September 2011 the FASB issued amendments to the standards for testing goodwill for impairment that will allow an entity to first assess qualitative factors to determine whether it needs to perform the two-step quantitative goodwill impairment test. An entity will not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not (a likelihood of more than 50 percent) that the fair value of the reporting unit is less than its carrying amount. The update includes a number of factors to consider in conducting the qualitative assessment. The amendments are effective for all entities for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011, with early adoption permitted. Our adoption of the amendments will not affect our results of operation, financial position or cash flows.

Comprehensive Income: In June 2011 the FASB issued amendments to improve the presentation of comprehensive income and improve convergence of U.S. generally accepted accounting principles (GAAP) and IFRS. The amendments give more importance to items reported in other comprehensive income (OCI) by eliminating the option to present components of OCI as part of the statement of changes in stockholders' equity. They require all nonowner changes in stockholders' equity to be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Both options require an entity to present each component of net income along with total net income, each component of OCI along with a total for OCI, and a total amount for comprehensive income. The amendments are to be applied retrospectively and are effective for nonpublic entities for fiscal years ending after December 15, 2012, and interim and annual periods thereafter. Our adoption of the amendments will not affect our results of operation, financial position or cash flows.

In December 2011 the FASB issued an update to the above amendment, to defer the effective date for amendments to the presentation of reclassification items out of accumulated other comprehensive income (AOCI). The update addresses concerns that presentation requirements about reclassifications of items out of AOCI would be costly for preparers and may add unnecessary complexity to financial statements. The update defers the effective date only for the changes that relate to the presentation of the reclassification adjustments, and will allow the FASB time to redeliberate whether to require presentation on the face of the financial statements of the effects of reclassifications out of AOCI on the components of net income and OCI for all periods presented.

Fair Value Measurement: The FASB issued an update in May 2011 for amendments that are the result of the FASB's and the International Accounting Standards Board's work to ensure that fair value has the same meaning and to develop common requirements for measuring fair value and disclosing information about fair value measurements in accordance with U.S. GAAP and IFRS. The amendments explain how to measure fair value but do not require additional fair value measurements and are not intended to establish valuation standards or affect valuation practices outside of financial reporting. The primary changes relate to: highest and best use and the valuation premise, measuring portfolios of financial instruments, blockage factors and other premiums and discounts, and disclosures (with certain exceptions for disclosure requirements for nonpublic entities). Other new or clarifying guidance relates to: the principal (or most advantageous) market, application to liabilities, and instruments classified within shareholders' equity. Remaining key differences relate to: day one gains and losses, measuring the fair value of certain investments (net asset value or its equivalent) and certain quantitative sensitivity analysis disclosures. The amendments are to be applied prospectively and are effective for nonpublic entities for annual periods beginning after December 15, 2011, with early application permitted, but no earlier than interim periods beginning after December 15, 2011. Our adoption of the amendments will not affect our results of operation, financial position or cash flows.

Troubled Debt Restructurings: In April 2011 the FASB issued an update that amends its accounting standards concerning determining whether a debt restructuring is a troubled debt restructuring (TDR). A restructuring is a TDR if a creditor for economic or legal reasons related to a debtor's financial difficulties grants a concession to the debtor that the creditor would otherwise not consider. The amendments provide additional guidance to creditors for evaluating whether the creditor has granted a concession and whether the debtor is experiencing financial difficulties. The amendments apply to all creditors, both public and nonpublic, that restructure receivables that are within the scope of the accounting and reporting requirements concerning TDRs. The update also ends the deferral of additional disclosures about TDR activities that had been required by an update issued in July 2010 concerning disclosures about the credit quality of financing receivables and the allowance for credit losses. The amendments are effective for nonpublic entities for annual periods ending on or after December 15, 2012, including interim periods within those annual periods. Our adoption of the amendments will not affect our results of operation, financial position or cash flows.

Notes to Consolidated Financial Statements

***Other (Income) and Other Deductions*:**

Year Ended December 31,	2011	2010
(Thousands)		
Interest and dividend income	**$(1,093)**	$(1,648)
Allowance for funds used during construction	**(11,096)**	(4,705)
Earnings from equity investments	**(4,480)**	(4,344)
Gain on sale of Seneca Lake Storage facility	**(12,397)**	-
Carrying costs on regulatory assets	**(19,964)**	(19,385)
Miscellaneous	**(739)**	(1,497)
Total other (income)	**$(49,769)**	$(31,579)
Early retirement of debt	**-**	$128,128
Civic donations	**$1,430**	1,268
Losses from tax equity investments	**57,157**	62,805
Miscellaneous	**3,801**	3,857
Total other deductions	**$62,388**	$196,058

Early retirement of debt: Iberdrola USA paid premiums in connection with the early retirement of long-term debt owed to an affiliate, Scottish Power, Limited as follows: premium of $82 million for the repayment of $400 million in November 2010 and premium of $46 million for the repayment of $300 million in December 2010.

***Principles of consolidation*:** These financial statements consolidate our majority-owned subsidiaries after eliminating intercompany transactions.

***Regulatory assets and liabilities*:** Our public utility subsidiaries currently meet the requirements concerning accounting for regulated operations for their electric and natural gas operations in New York and Maine; however, we cannot predict what effect the competitive market or future actions of regulatory entities would have on their ability to continue to do so. If our public utility subsidiaries were to no longer meet the requirements concerning accounting for regulated operations for all or a separable part of their operations, they may have to record certain regulatory assets and regulatory liabilities as an expense or as revenue, or include them in accumulated other comprehensive income.

Pursuant to the requirements concerning accounting for regulated operations our utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. Substantially all regulatory assets for which funds have been expended are either included in rate base or are accruing carrying costs. As a result of the New York rate decision (see Note 15), the majority of regulatory assets and liabilities for NYSEG and RG&E were included in rate base. Our operating utilities also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs.

Our three operating utilities are allowed to defer the costs of service restoration resulting from extraordinary storms when they meet certain criteria for severity and duration. During 2011 we experienced an unusually high level of restoration costs resulting from storms including Hurricane Irene, tropical storm Lee and an early winter snowstorm in late October. We have incurred a total of $99 million in 2011 related to these storms. The amount deferred, which reflects the excess over amounts currently allowed in rates is $85 million. The method of recovery of the costs will be determined in the future rate cases for each company.

Unfunded future income taxes and deferred income taxes are amortized as the related temporary differences reverse. Unamortized loss on debt reacquisitions is amortized over the lives of the related debt issues. Nuclear plant obligations, demand side management program costs, gain on sale of generation assets, other regulatory assets and other regulatory liabilities are amortized over various periods in accordance with each operating utility's current rate plans. Amortization of total regulatory assets net of amortization of total regulatory liabilities was $34 million in 2011 and $74 million in 2010.

Other regulatory assets and other regulatory liabilities consisted of:

December 31, (Thousands)	2011	2010
Other postretirement benefits	**$9,528**	$12,428
Loss on sale of RG&E Oswego generating unit	**10,890**	16,335
Asset retirement obligation	**28,750**	28,455
Deferred storm costs	**134,699**	54,479
Deferred pension costs	**43,458**	47,913
Deferred property tax	**45,307**	43,609
Deferred meter replacement costs	**23,876**	5,916
Deferred natural gas costs	**5,267**	1,077
Nonbypassable wires charge	**3,400**	4,004
Incremental assessment	**-**	11,261
Cost to achieve efficiency initiatives	**20,231**	29,966
Other	**39,435**	35,738
Total other regulatory assets	**$364,841**	$291,181
Deferred natural gas costs	**$12,968**	$8,839
Asset retirement obligation	**4,417**	4,419
Economic development	**39,096**	35,951
Pension and other postretirement benefits	**11,082**	13,435
Plant decommissioning	**12,510**	12,545
Deferred property tax	**15,923**	8,758
Nonbypassable wires charge	**-**	20,033
Environmental	**6,735**	4,725
Merger capital expense target customer credit	**16,800**	-
Earning sharing mechanism	**8,241**	-
Other	**67,027**	58,894
Total other regulatory liabilities	**$194,799**	$167,599

Related party transactions: As part of the Iberdrola S.A. group, Iberdrola USA is a party to a number of intercompany revolving credit facilities under which it acts as either the lender or the borrower. The agreements allow Iberdrola USA as a borrower to supplement its own liquidity resources by accessing the liquidity resources of Iberdrola S.A. and, as a lender, to provide liquidity to other affiliates of Iberdrola S.A. in the U.S.

In January 2012, Iberdrola USA entered into two intercompany revolving credit facilities, with expiration dates of December 31, 2012, intended to provide temporary liquidity to Iberdrola Renewables Holdings, Inc. (IRHI), an affiliate company and indirect subsidiary of Iberdrola S.A. Iberdrola USA is the borrower and Scottish Power Limited (Scottish Power) is the lender in an agreement with a $400 million limit. As of February 3, 2012, there was $250 million outstanding under this agreement. Iberdrola USA is the lender and IRHI is the borrower in an agreement with a $600 million limit. In both agreements the borrower pays a facility fee of 15 basis points and borrows at 98 basis points over Libor. As of February 3, 2012, there was $550 million outstanding under this agreement.

In November 2010 Iberdrola USA entered into an agreement where it is the lender in a $100 million revolving credit facility and IRHI is the borrower. Under the agreement, the borrowing margin is 100 basis points over Libor. The agreement expires in 2015 and has no facility fees. There was no amount outstanding under this agreement at December 31, 2011 and 2010.

We have a depository agreement with Scottish Power under which, in November 2010, we deposited $550 million for investment. In December 2010 we redeemed those funds. There was no amount outstanding under the depository agreement at December 31, 2011, and 2010

See Note 5 concerning amounts we owe to Scottish Power under a debt agreement. Interest expense on the debt for the year ended December 31 was $44 million for 2011 and $90 million for 2010.

See Note 8 concerning our related party transactions with respect to tax equity investments.

Revenue recognition**:** We recognize revenues upon delivery of energy and energy-related products and services to our customers.

Pursuant to a Maine state law, CMP is prohibited from selling power to its retail customers. CMP generally does not enter into purchase or sales arrangements for power with ISO New England Inc., (ISO-NE) the New England Power Pool, or any other independent system operator or similar entity. CMP generally sells all of its power entitlements under its nonutility generator (NUG) and other purchase power contracts to unrelated third parties under bilateral contracts. If the Maine Public Utilities Commission (MPUC) does not approve the terms of bilateral contracts, it can direct CMP to sell power entitlements that it receives from those contracts on the spot market through ISO-NE.

NYSEG and RG&E enter into power purchase and sales transactions with the New York Independent System Operator (NYISO). When NYSEG and RG&E sell electricity from owned generation to the NYISO, and subsequently repurchase electricity from the NYISO to serve their customers, they record the transactions on a net basis in their statements of income. NYSEG and RG&E net their purchase and sale transactions with the NYISO on an hourly basis.

NYSEG's and RG&E's electric and gas rate plans each contain a revenue decoupling mechanism under which the company's actual energy delivery revenues are compared on a periodic basis, with the authorized delivery revenues and the difference accrued, with interest, for refund to, or recovery from, customers, as applicable. (See Note 15.)

In addition, our regulated utilities accrue revenue pursuant to the various regulatory provisions to record regulatory assets for revenues that will be collected in the future.

Taxes**:** We file a consolidated federal income tax return and unitary and/or combined state income tax returns in certain jurisdictions and allocate income taxes among Iberdrola USA and its subsidiaries in proportion to their contribution to consolidated taxable income. The determination and allocation of our income tax provision and its components are outlined and agreed to in the tax sharing agreements among Iberdrola USA and its subsidiaries.

Deferred income taxes reflect the effect of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and the amount recognized for tax purposes. We amortize investment tax credits over the estimated lives of the related assets.

We account for sales tax collected from customers and remitted to taxing authorities on a net basis.

We classify all interest and penalties related to uncertain tax positions as income tax expense.

Use of estimates and assumptions: The preparation of our consolidated financial statements in conformity with generally accepted accounting principles requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for doubtful accounts and unbilled revenues; (2) asset impairments, including goodwill; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; and (8) earnings sharing mechanism (ESM), nonbypassable wires charges and environmental remediation liability. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside experts to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Note 2. Sale of Natural Gas Companies

On November 16, 2010, we sold three of our natural gas holding company subsidiaries and their natural gas distribution utilities to UIL at an after-tax loss of $382 million, including impairments of goodwill totaling $275.8 million. The three holding companies and related natural gas distribution utilities are: CTG and CNG, CEC and SCG, and BER and BGC. Pursuant to the purchase agreement we retained our nonutility subsidiaries CNE Energy Services Group, Inc. and TEN Companies, Inc. (TEN Cos.) at the time of the transaction.

The transaction was valued at $1,296 million, including the assumption of approximately $386 million of debt. We received approximately $918 million in cash at closing, which reflects closing adjustments of $8 million primarily for estimated cash balances and changes in net working capital.

The agreement provided for an adjustment to the final purchase price for actual cash and working capital balances as of the date of the sale. In May 2011 IUSA made a payment to UIL of $11 million for this working capital adjustment. Income taxes on the sale were also adjusted by $15 million in 2011 to reflect the actual income tax expense resulting from filing our 2010 tax return in September 2011, including the effect of the working capital payment.

The following provides a summary of the discontinued operations presented in the consolidated statements of income for the periods indicated in 2011 and 2010:

	2011 activity related to sale	Period January 1, to November 16, 2010
(Thousands)		
Operating Revenues		
Sales and services	-	$643,533
Operating Expenses		
Natural gas purchased	-	366,726
Depreciation and amortization	-	21,540
Goodwill impairment	-	275,802
Other operating expenses	-	165,786
Total Operating Expenses	-	829,854
Operating (Loss) Income	-	(186,321)
Other (Income) Deductions, net	-	(6,140)
Loss on Sale of Natural Gas Companies	**$11,083**	88,243
Interest Charges, Net	-	28,292
(Loss) Income Before Income Taxes	**(11,083)**	(296,716)
Taxes on Sale of Natural Gas Companies	**(14,923)**	18,300
Income Taxes	-	23,881
Income (Loss) From Discontinued Operations	**$3,840**	$(338,897)

The above Depreciation and amortization expense for the period ended November 16, 2010 excludes approximately $21 million of depreciation and amortization for the period of time that we classified the assets as held for sale. The Interest Charges, Net represent interest on the direct obligations of the natural gas companies sold. Transaction costs of $2 million are included in the loss on sale for 2010.

Note 3. Goodwill

We do not amortize goodwill, but test it for impairment at least annually. Impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of our marginal, weighted-average cost of capital, and forecasted cash flows. We test the reasonableness of the conclusions of our impairment testing using a range of discount rates and a range of assumptions for long-term cash flows. Our decision in May 2010 to sell the natural gas companies helped meet a key strategic objective of our parent, Iberdrola S. A., as it allows us to focus on electric operations. The decision to sell represented a triggering event and we immediately performed an impairment test of the goodwill for SCG, CNG and BGC in accordance with the two step process described in Note 1. We determined that the carrying value of the combined companies exceeded the purchase price agreed to by UIL, resulting in a goodwill impairment of $275.8 million. We had no impairment of goodwill in 2011 or 2010 as a result of our annual impairment testing, which we perform in the third quarter each year. No impairment was indicated within any of the ranges of assumptions analyzed for our New York, Maine or nonutility reporting units. There were no events or circumstances subsequent to our annual impairment testing that required us to update the test.

The carrying amount of goodwill as of December 31, 2011 and 2010, is shown in the following table. Goodwill has not been adjusted to reflect Iberdrola's purchase of Energy East.

	2011	2010
(Thousands)		
Balance as of January 1		
Goodwill	**$983,888**	$1,526,822
Accumulated impairment losses	**(242)**	(242)
	983,646	1,526,580
Goodwill related to sale of business units	-	(267,132)
Impairment for natural gas companies sold	**-**	(275,802)
Balance as of December 31		
Goodwill	**983,888**	983,888
Accumulated impairment losses	**(242)**	(242)
	$983,646	$983,646

Note 4. Income Taxes

Year Ended December 31,	2011	2010
(Thousands)		
Current		
Federal	**$(43,709)**	$(259,708)
State	**16,095**	(6,594)
Current taxes charged to expense	**(27,614)**	(266,302)
Deferred		
Federal	**78,895**	234,214
State	**1,285**	10,237
Deferred taxes charged to expense	**80,180**	244,451
Investment tax credit adjustments	**(2,124)**	(2,273)
Total for Continuing Operations	**$50,442**	$(24,124)

The increase in current income tax expense for 2011, along with the corresponding decrease in deferred income tax expense, as compared to 2010, is driven primarily by our 2011 operations generating a tax loss. This tax loss was driven primarily by our electing 50-percent and 100-percent expensing on certain qualified property placed in service during 2011. Such tax losses will be utilized in future tax years, as IUSA currently cannot carryback its losses to prior tax years. Consequently, the 2011 tax losses are being recorded through deferred income tax expense.

The $43.7 million impact on current federal income tax expense for 2011 is limited to certain adjustments recorded for the impacts of the 2010 tax return and reflected in continuing operations. The impact to the 2010 tax return is primarily the result of the filing of a change in method of accounting for capitalized overhead costs. The filing of the change in method of accounting for the 2010 tax return was not anticipated at year-end and therefore was not reflected in the 2010 income tax provision. In 2010, the tax losses generated by continuing operations were utilized to offset the substantial tax gain related to the sale of the natural gas companies.

Notes to Consolidated Financial Statements

Our tax expense differed from the expense at the statutory rate of 35% due to the following:

Year Ended December 31,	2011	2010
(Thousands)		
Tax expense at statutory rate	**$115,423**	$37,740
Depreciation and amortization not normalized	**5,154**	11,669
Investment tax credit amortization	**(2,124)**	(2,273)
Removal costs	**(8,735)**	(7,847)
Medicare subsidy	**2,742**	2,708
Tax return and audit adjustments	**(2,873)**	(3,341)
Tax equity investment depreciation not normalized	**(38,092)**	(37,031)
Tax equity investment production tax credits	**(25,341)**	(24,245)
State taxes, net of federal benefit	**11,298**	2,368
Other, net	**(7,010)**	(3,872)
Total for Continuing Operations	**$50,442**	$(24,124)

Income taxes were $65.0 million less in 2011 than they would have been at the federal statutory rate of 35% and $61.8 million less in 2010. The 2011 and 2010 effective tax rate was less than the statutory rate primarily due to the tax benefits, including production tax credits, generated from our tax equity investments in two wind farm partnerships.

Our consolidated deferred tax assets and liabilities consisted of:

December 31,	2011	2010
(Thousands)		
Current Deferred Income Tax Assets	**$74,189**	$62,081
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property related	**$1,629,375**	$1,379,484
Pension	**241,489**	249,182
Unfunded future income taxes	**176,449**	166,764
Deferred (gain) on sale of generation assets	**17,567**	26,008
Accumulated deferred investment tax credits	**21,629**	23,753
Federal and state net operating loss carryforwards	**(159,012)**	(50,985)
Production Tax Credit carryforward	**(64,129)**	-
Other postretirement benefits	**(100,116)**	(102,163)
Positive benefits adjustments merger order	**(49,288)**	(79,365)
Other	**(26,522)**	(25,994)
Total Noncurrent Deferred Income Tax Liabilities	**1,687,442**	1,586,684
Less amounts classified as regulatory liabilities		
Deferred income taxes	**486,507**	368,564
Noncurrent Deferred Income Tax Liabilities	**$1,200,935**	$1,218,120
Deferred tax assets	**$473,256**	$320,588
Deferred tax liabilities	**2,086,509**	1,845,191
Net Accumulated Deferred Income Tax Liabilities	**$1,613,253**	$1,524,603

Notes to Consolidated Financial Statements

Iberdrola USA and its subsidiaries have the following loss carryforward amounts:
Federal - $304 million, state of New York - $786 million, Maine - $503 million, and Connecticut - $22 million, which expire between 2027 and 2031. We have production tax credit carryforwards of $64 million. Deferred tax assets are reduced by a valuation allowance when it is more likely than not that some portion or the entire deferred income tax asset will not be realized. We believe that it is more likely than not that we will produce sufficient taxable income in the future to realize all of our deferred income tax assets.

Reconciliation of Gross Income Tax Reserves	**2011**	2010
(Thousands)		
Balance as of January 1	**$32,710**	$39,498
Increases for tax positions related to prior years	**14,856**	-
Disposition of amounts related to sale of natural gas companies	**-**	(6,788)
Reduction for tax position related to settlements with taxing authorities	**(21,871)**	-
Balance as of December 31	**$25,695**	$32,710

The total gross unrecognized tax benefits as of December 31, 2011, were $27.9 million, including gross income tax reserves of $25.7 million and interest of $2.2 million. Including interest, $9.2 million of the total gross unrecognized tax benefits would affect the effective tax rate, if recognized. Gross income tax reserves decreased $7.0 million in 2011 primarily due to settlements with taxing authorities of $21.9 million offset by increases for additional positions reserved in 2011 of $14.9 million.

We have been audited through 2005 for federal income taxes. The statute of limitations in all state jurisdictions except New York State has expired for all years through 2007. Our federal returns for 2006 through 2009 and New York State returns for 2007 through 2009 are currently under review. We anticipate that the reviews will be completed in 2012. We cannot predict the ultimate outcome of the reviews.

***Safe Harbor Method for capitalizing expenditures*:** In 2011 the Internal Revenue Service issued a revenue procedure to provide a safe harbor method of accounting that taxpayers may use to determine whether expenditures to maintain, replace or improve electric transmission and distribution property must be capitalized under Section 263 (a) of the Internal Revenue Code. This revenue procedure also provides procedures to obtain automatic consent to change to the safe harbor method of accounting. We have used this method in accounting for our 2011 results.

Capitalization of tangible assets: In December 2011, the Internal Revenue Service issued revised regulations on the capitalization of tangible assets, withdrawing proposed regulations issued in 2008 and issuing new temporary and proposed regulations. The new guidance, effective January 1, 2012, is intended to clarify existing standards and provide certain bright-line tests for applying the standards. We intend to review and comply with the revised regulations.

Bonus depreciation: As a result of the passage of The Small Business Jobs Act in September 2010 and the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 in December 2010, certain capital additions qualify for 50% bonus depreciation and 100% expensing, respectively, for tax purposes. Iberdrola USA and its affiliates have elected to apply the 50% bonus and 100% expensing to the additions it has determined qualify for this accelerated tax depreciation. There is no earnings effect related to this election because the accelerated tax depreciation creates a temporary difference that requires the establishment of a deferred tax liability.

***Elimination of tax deduction related to Medicare Part D Subsidy*:** The Patient Protection and Affordable Care Act (PPACA) and the Health Care and Education Reconciliation Act of 2010 (H.R. 4872) were signed into U.S. law in late March 2010. We receive a federal subsidy because we sponsor retiree health benefit plans that provide a benefit that is at least actuarially equivalent to the benefits under Medicare Part D. The subsidy is known as the Retiree Drug Subsidy (RDS or the subsidy). The RDS payments we receive are not currently taxed. A provision in the PPACA changes the tax treatment of the RDS, requiring the amount of the subsidy received to be offset against the amount of retiree health care payments that would be eligible for a tax deduction. As a result, the subsidy received would reduce an employer's tax deduction for the costs of retiree health care. Our subsidy receipts will effectively become taxable in tax years that begin after December 31, 2012.

In accordance with U.S. GAAP concerning accounting for income taxes, a reporting entity is required to immediately recognize the effect of a change in tax law in continuing operations in the income statement in the period that includes the enactment date. We recorded the effect of the change related to the RDS in the quarter ended March 31, 2010, due to the fact that we accounted for the future tax benefit on an accrual basis. In accounting for the effect of the change for U.S. GAAP reporting, an employer that captured the tax benefit of future subsidies on an accrual basis would now be required to reduce the accumulated deferred tax asset on its balance sheet related to the accrued estimated deductible retiree health care payments to reflect the fact that the future deduction will now be reduced by the collection of the accrued subsidy.

Companies that meet the requirements concerning accounting for regulated operations offset that decrease with the establishment of a regulatory asset. As a result, in 2010 we recorded a regulatory asset for unfunded future income taxes of approximately $26 million and reduced our deferred income tax asset related to the costs of retiree health care by approximately $17 million for NYSEG and RG&E combined. In addition, because the recognition of the unfunded future income tax regulatory asset is considered a temporary difference, we have recognized an associated deferred income tax liability of approximately $9 million. There is no immediate effect on the income statement under this accounting, only our balance sheet is affected. The amortization of the $26 million regulatory asset and associated $9 million deferred tax liability commenced on September 1, 2010 in accordance with the provisions of the NYSEG and RG&E rate settlements. The amortization period is 40 months.

In 2010, CMP recorded a $5.6 million income tax expense as a result of the tax law change. In 2011 CMP reached a settlement agreement for recovery of approximately $4.3 million of that amount pursuant to the mandated cost provision of its current rate plan.

Note 5. Long-term Debt

At December 31, 2011 and 2010, our consolidated long-term debt was:

Company		Interest Rates	Maturity	Amount (Thousands) 2011	2010
	First mortgage bonds [1]				
RG&E	Series TT, WW, VV, XX, YY & AAA	4.10% - 8.00%	2019 - 2033	**$600,000**	$536,000
RG&E	PCN 2004 Series A	4.75%	2016	**10,500**	10,500
RG&E	PCN 2004 Series B	5.375%	2032	**50,000**	50,000
RG&E	PCN Series C	5.00%	2016	**29,350**	29,350
CMP	Series A& B	4.20% - 5.70%	2019 - 2021	**300,000**	150,000
Total first mortgage bonds				**989,850**	775,850
	Unsecured pollution control notes (PCNs), fixed				
NYSEG	1985 Series A, B & D	2.125% - 2.250%	2015	**132,000**	132,000
NYSEG	1994 Series B & C	3.00%	2013	**101,000**	101,000
NYSEG	2004 Series B	5.35%	2028	**70,000**	70,000
NYSEG	2006 Series A	3.00%	2013	**12,000**	12,000
RG&E	1998 Series A	5.95%	2033	**-**	25,500
CMP	Industrial Development Authority of the state of New Hampshire Notes	5.375%	2014	**19,500**	19,500
Total unsecured pollution control notes, fixed				**334,500**	360,000
	Unsecured PCNs, variable				
NYSEG	2005 Series A	.10%	2026	**25**	25
NYSEG	2004 Series A	.25%	2027	**-**	175
NYSEG	2004 Series C	.70%	2034	**100,000**	100,000
RG&E	1997 Series A & B	.40%	2032	**68,000**	68,000
Total unsecured pollution control notes, variable				**168,025**	168,200
	Various long-term debt				
NYSEG	Unsecured Notes	5.50% - 6.15%	2012 - 2023	**600,000**	600,000
CMP	Series E & F Medium Term Notes	5.10% - 6.65%	2012 - 2037	**268,200**	293,200
Chester	Promissory and Senior Notes	7.05% - 10.48%	2020	**10,457**	11,640
Total various long-term debt				**878,657**	904,840
Obligations under capital leases				**13,618**	15,537
Unamortized premium (discount) on debt, net				**3,985**	3,962
				2,388,635	2,228,389
Less debt due within one year, included in current liabilities				**155,637**	89,055
Total Other long-term debt				**2,232,998**	2,139,334
	Long-term debt owed to affiliates				
Iberdrola USA	Unsecured Notes	5.90%	2013	**300,000**	300,000
Iberdrola USA	Unsecured Notes	7.08%	2019	**350,000**	350,000
Total Long-term debt owed to affiliates				**650,000**	650,000
Total Long-term Debt				**$2,882,998**	$2,789,334

[1] The first mortgage bonds are secured by liens on substantially all of the respective utility's properties.

Notes to Consolidated Financial Statements

In January 2012 NYSEG issued a notice to call $100 million of 5.5% unsecured notes due in November 2012 at a “make-whole” call price producing a yield of the treasury rate plus 25 basis points. The notes will be redeemed in February 2012.

In April 2011 CMP priced $150 million of Series B first mortgage bonds and $100 million of Series C first mortgage bonds; The Series B bonds were issued at par in July 2011, will mature in 2021 and bear a coupon of 4.20%. The Series C bonds were issued at par in January 2012 will mature in 2042 and bear a coupon of 5.68%. The proceeds of these bonds were used to reduce short-term debt and to fund capital expenditures.

In May 2011 RG&E priced $125 million of Series AAA first mortgage bonds. The Series AAA bonds were issued at par in July 2011 will mature in 2021 and bear a coupon of 4.10%. The proceeds of these bonds were used to reduce short-term debt and to fund capital expenditures.

In September 2011 NYSEG issued $132 million of tax-exempt refunding bonds in three separate series with maturity dates in 2015 and bearing coupons of 2.125%-2.25%. The proceeds of these bonds were used to redeem at par $132 million of bonds bearing coupons of 4.0%-4.1% with the same maturity dates.

In December 2011, RG&E issued a notice to call at par $25.5 million of fixed rate tax-exempt bonds in January 2012. RG&E deposited, with the trustee, funds sufficient to cover the principle and interest due on the redemption date and the bonds have been legally defeased and therefore derecognized within these consolidated financial statements.

As of December 31, 2011, NYSEG and RG&E had outstanding $573 million of tax-exempt PCNs, of which $252 million have coupons fixed to maturity, $113 million are notes with a mandatory redemption date in 2013, $40 million are notes with a mandatory redemption date in 2016, $100 million are 7-day auction rate notes and $68 million are 35-day auction rate notes. The notes with mandatory redemption dates in 2013 and 2016 have maturity dates in 2024 through 2032 and may be remarketed as tax-exempt bonds in a different interest rate mode after the mandatory redemptions.

Federal and state regulatory restrictions limit our ability to borrow funds from our utility subsidiaries. While we may be able to borrow funds from our utility subsidiaries by obtaining regulatory approvals and meeting certain conditions, we do not expect to seek such loans. Iberdrola USA has no secured indebtedness and none of its assets are mortgaged, pledged or otherwise subject to lien. None of Iberdrola USA’s debt obligations are guaranteed or secured by its subsidiaries.

In April 2009 the obligor on our $1.3 billion of outstanding unsecured debt was transferred to Iberdrola International, a subsidiary of Iberdrola S.A. In exchange we entered into a debt agreement with Scottish Power, Limited (Scottish Power), another subsidiary of Iberdrola S.A., for $1.05 billion and received an equity infusion of $250 million from Iberdrola S.A. In May 2009 we borrowed an additional $300 million from Scottish Power. On November 17, 2010, we repaid $400 million of the debt, at a premium of $82 million, and on December 29, 2010, we repaid $300 million of the debt at a premium of $46 million. Our outstanding balance with Scottish Power as of December 31, 2011, was $650 million.

In June 2010 NYSEG converted $113 million of variable-rate pollution control notes (PCNs) (1994 Series B & C and 2006 Series A) to fixed rate mandatory tender bonds due in 2013. Concurrent with that transaction NYSEG redeemed and did not remarket an additional $74 million of its variable-rate PCNs (1994 Series D1 & D2) and terminated a $190 million credit facility that had served as backstop liquidity for the variable rate PCNs prior to their conversion or redemption.

On December 30, 2010, RG&E completed a make-whole redemption of $100 million of 6.95% Series TT first mortgage bonds, due in April 2011, at a premium of $1.6 million, using excess cash on hand.

As of December 31, 2010, NYSEG and RG&E had outstanding $598 million of tax-exempt PCNs, of which $277 million have coupons fixed to maturity, $113 million are notes with a mandatory redemption date in 2013, $40 million are notes with a mandatory redemption date in 2016, $100 million are 7-day auction rate notes and $68 million are 35-day auction rate notes. The notes with mandatory redemption dates in 2013 and 2016 have maturity dates in 2024 through 2032 and may be remarketed as tax-exempt bonds in a different interest rate mode after the mandatory redemptions.

At December 31, 2011, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years is:

2012	2013	2014	2015	2016
$155,637	$451,897	$22,759	$134,634	$182,054

Cross-default provisions**:** Iberdrola USA has a provision in its revolving credit facility, which provides that its default with respect to any other debt in excess of $50 million will be considered a default under its revolving credit facility.

We are in compliance with all debt covenants as of December 31, 2011 and 2010.

Note 6. Bank Loans and Other Borrowings

Our regulated operating utilities rely on a combination of bank provided and intercompany revolving credit facilities to fund short-term liquidity needs. In July 2011, NYSEG, RG&E and CMP jointly entered into a bank provided revolving credit facility (the “Joint Facility”) allowing maximum borrowings of up to $600 million in aggregate. Sublimits that total to the aggregate limit apply to each joint borrower and can be altered within the constraints imposed by maximum limits that apply to each joint borrower. This Joint Facility, which will expire in 2016, replaced a similar facility with a $475 million aggregate limit which was to have expired in 2012. Each borrower pays a facility fee ranging from 20 to 25 basis points annually depending on the rating of its unsecured debt.

In February 2012 CMP and NYSEG established commercial paper programs with limits of $350 million and $200 million respectively. The Joint Facility serves as the backstop to these programs. The companies intend to use commercial paper as an alternative to revolving credit facilities as source of short-term credit.

Iberdrola USA is the sole borrower in a bank provided revolving credit facility allowing maximum borrowings of up to $300 million. This facility expires in 2012. Iberdrola USA pays a facility fee of 6 basis points annually. In addition, Iberdrola USA is the borrower on a $600 million intercompany revolving credit facility in which Iberdrola Financiación S.A.U., a subsidiary of Iberdrola S.A. based in Spain, is the lender. This agreement expires in 2016 and Iberdrola USA pays a facility fee of 15 basis points. Iberdrola USA uses these facilities to fund its own liquidity needs, the liquidity needs of its unregulated subsidiaries and affiliates and to fund draws on the supplemental intercompany revolving credit facilities with the regulated operating utilities.

There was $75 million of short-term debt outstanding at December 31, 2011, and $142 million outstanding at December 31, 2010. The weighted-average interest rate on short-term debt was 0.7%

at December 31, 2011, and 0.5% at December 31, 2010. At February 3, 2012, there was $371 million of short-term debt outstanding. The increase in short-term debt since December 31, 2011, was driven primarily by the actions taken to provide temporary liquidity to IRHI discussed above.

In our revolving credit facility we covenant not to permit, without the consent of the lender, our ratio of consolidated indebtedness to consolidated total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to consolidated total capitalization, the facility excludes from consolidated net worth the balance of Accumulated other comprehensive income (loss) as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness Iberdrola USA may maintain. Continued unremedied failure to comply with those covenants for 15 days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of consolidated indebtedness to consolidated total capitalization pursuant to the revolving credit facility was 0.47 to 1.00 at December 31, 2011. We are not in default as of December 31, 2011.

In the revolving credit facility in which our operating utilities are joint borrowers, each joint borrower covenants not to permit, without the consent of the lender, its ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to total capitalization, the facility excludes from consolidated net worth the balance of Accumulated other comprehensive income (loss) as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness each borrower may maintain. Continued unremedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity for the party in default. We are not in default as of December 31, 2011.

Note 7. Redeemable Preferred Stock of Subsidiaries, Noncontrolling Interests

The redeemable preferred stock of subsidiaries are noncontrolling interests because they contain a feature that allows the holders to elect a majority of the subsidiary’s board of directors if preferred stock dividends are in default in an amount equivalent to four full quarterly dividends. Such a potential redemption-triggering event is not solely within the control of the subsidiary.

At December 31, 2011 and 2010, our consolidated redeemable preferred stock, noncontrolling interests was:

Subsidiary and Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding[1]	Amount (Thousands) 2011	2010
CMP, 6% Noncallable	$100	-	2,347	**$235**	$235
CMP, 4.60%	100	101.00	11,664	**1,167**	1,167
CMP, 4.75%	100	101.00	9,028	**903**	903
NYSEG, 3.75%	100	104.00	78,379	**7,838**	7,838
NYSEG, 4.50% (1949)	100	103.75	11,800	**1,180**	1,180
NYSEG, 4.40%	100	102.00	7,093	**709**	709
NYSEG, 4.15% (1954)	100	102.00	4,317	**432**	432
NYSEG, Limited Voting Junior	1	-	1	**-**	-
RG&E Limited Voting Junior	1	-	1	**-**	-
Total				**$12,464**	$12,464

[1] At December 31, 2011, Iberdrola USA and its subsidiaries had 6,632,519 shares of $100 par value preferred stock, 16,800,000 shares of $25 par value preferred stock, 1,000,000 shares of $100 par value preference stock and 5,000,000 shares of $1 par value preference stock authorized but unissued.

Note 8. Tax Equity Investments

In April 2009 Iberdrola USA, through its subsidiary CNE Energy, acquired an interest in Aeolus Wind Power V LLC (Aeolus V) in exchange for $305.4 million in cash. CNE Energy purchased its membership interest in Aeolus V from PPM Wind Energy LLC (PPM), an affiliate, which contributed its 100% ownership of various wind farms to Aeolus V.

The main characteristics of our investment in Aeolus V are as follows:

- PPM retains day-to-day management of the wind farms. Defined major decisions require consent from CNE Energy.
- As a minority shareholder, CNE Energy has the right to a substantial portion of the profits and tax credits generated by the wind farms up to the return level established at the beginning of the investment contract.
- CNE Energy initially holds a 50% interest in Aeolus V until it achieves a stipulated 7.5% return, after which it is entitled to maintain a 5% ownership interest.
- PPM has the option to purchase, at fair market value, CNE Energy’s remaining residual equity interest, which is exercisable after CNE Energy achieves its agreed upon return.
- Whether or not CNE Energy obtains the agreed upon return depends on the economic performance of the wind farms. While PPM is bound to operate and maintain the facilities in an efficient manner and maintain appropriate insurance, it is not obligated to deliver cash to CNE Energy over and above the aforementioned profits and tax credits.

On December 17, 2010, we acquired, also through CNE Energy, an interest in Aeolus Wind Power VI LLC (Aeolus VI) in exchange for $236 million in cash. CNE Energy purchased its membership interest in Aeolus VI from PPM, which contributed its 100% ownership of four wind farms to Aeolus VI. The partnership terms for Aeolus VI are similar to the terms described above for Aeolus V.

CNE Energy uses an equity method referred to as Hypothetical Liquidation at Book Value (HLBV) to account for its investments in Aeolus V and in Aeolus VI. The application of that method results in CNE Energy recording a gain or loss on its investment based on the cash implications of a liquidation at book value, with a corresponding adjustment to the investment account. In addition, the HLBV method requires the tax effects related to Production Tax Credits (PTCs) (applies to Aeolus V only) and taxable income (loss) to be recorded in income taxes on the income statement. The primary difference in accounting for the Aeolus VI investment is that the Aeolus VI wind farms received cash grants from the federal government and consequently are not eligible for PTCs. Finally, the HLBV method requires a credit to accumulated deferred income taxes on the balance sheet and a debit to income taxes on the income statement for an amount representing the statutory rate applied to the difference between the tax basis and the book basis of the investment.

The following table shows the effects of our investments on our consolidated income statements and balance sheets:

Income statement for the year ended December 31,	**2011**	**2010**
(Thousands)		
Other (deductions), losses from tax equity investments	$(57,157)	$(62,805)
Income tax (benefit)	(83,438)	(83,258)
Total income statement benefit	$26,281	$20,453

Balance sheet at December 31,	**2011**	**2010**
(Thousands)		
Tax equity investment	$420,858	$478,016
Deferred tax liabilities, noncurrent	$(30,629)	$(151,149)

The following table provides summary financial information for Aeolus V and Aeolus VI:

Income statement for the year ended December 31,	**2011**	**2010**
(Thousands)		
Revenues*	$117,983	$84,958
Operating income	$(4,490)	$26,757
Net Income (Loss)	$(30,338)	$2,097

*Including PTCs for Aeolus V only.

Balance sheet at December 31,	**2011**	**2010**
(Thousands)		
Total Assets	$2,043,390	$2,050,155
Total Equity	$1,546,196	$1,700,201

Note 9. Commitments and Contingencies

***Capital spending*:** We have commitments in connection with our capital spending program. As part of the rate plans approved for NYSEG and RG&E in August 2010, capital spending targets were established. Aggregate capital expenditure targets for the two companies are $340 million for 2012 and $397 million for 2013. If at the end of the rate plan in 2013, the revenue requirement on plant has been lower than that assumed in the rate plans based on these capital expenditure levels, the companies will defer the revenue requirement impact for the benefit of customers.

On June 10, 2010, the Maine Public Utilities Commission granted approval for CMP's Maine Power Reliability Program (MPRP). The MPRP, expected to be completed in 2015, is a $1.4 billion project that will support the development of new renewable energy resources and help ensure long-term reliability for customers by increasing the capacity and efficiency of the New England transmission grid. The MPRP includes the construction of five new 345-kilovolt substations and related facilities linked by approximately 450 miles of new or rebuilt transmission lines. The costs for the MPRP project as of December 31, 2011 totaled approximately $543 million with $63 million included in Utility Plant and $480 million included in Construction work in progress.

CMP's Advanced Metering Infrastructure (AMI) project, expected to be completed by the end of 2012, will provide its approximately 620,000 residential, commercial and industrial customers with information on electrical usage, allowing them to better manage energy use and cost. The new meters will also help CMP reduce costs, enhance system planning and pinpoint problems more quickly during outages. Reduced costs will result from operational efficiencies related to billing, account openings and closings, and credit and collections as well as instantaneous meter reading. The total estimated cost of the AMI project is $166 million, and is being funded in part by a $96 million grant from the U.S. Department of Energy (DOE), which was approved on April 26, 2010. The $96 million grant represents 50% of the estimated costs plus 50% of the net book value of removed meters. The costs for the AMI project as of December 31, 2011 totaled approximately $69 million (net of $78 million of grants received). The net costs include $51 million included in Utility Plant and $18 million included in Construction work in progress.

***CMP customer charge-offs*:** Under Maine electric restructuring law, Maine electric delivery utilities are required to bill customers for delivery and supply service. This includes managing delivery and supply accounts receivable and uncollectibles. In October 2010 the MPUC initiated a proceeding to investigate CMP's credit and collection practices, and, in particular, whether CMP complies with the MPUC's new credit and collection rules, including the treatment of unpaid customer balances for delivery charges and for supply charges. The parties agreed that to initiate the proceeding the MPUC Staff would issue a Bench Analysis. On March 14, 2011, the Staff issued its Bench Analysis, which takes the position that CMP has properly implemented the MPUC's new credit and collection procedures as it relates to partial customer payments, and that CMP's process for calculating and collecting customer deposits is reasonable and not inconsistent with the MPUC's rules.

Concerning the treatment of unpaid customer balances for delivery and supply charges, the Bench Analysis takes the position that CMP's process of applying deposits to finaled accounts (using the same partial payment methodology) has disproportionately credited delivery receivables over supply receivables. The Bench Analysis also criticizes CMP for the increase in accounts receivable. Taking all of those factors collectively into account, but not attributing any specific amount to any particular cause, the Bench Analysis concludes that CMP's rate of charge-offs for supply receivables should have been comparable to its rate of delivery charge-offs during this period. Based on that conclusion, the Bench Analysis contends that $10.6 million of standard offer receivables should be retroactively reclassified to delivery receivables and the supply offer retainage account should be credited accordingly. CMP disagrees with the assumptions and conclusions in the Bench Analysis. CMP has conducted discovery on the Bench Analysis and filed a response, including expert testimony, on June 24, 2011. A final MPUC decision is not expected until the second quarter of 2012. CMP cannot predict the outcome of this matter.

***Homer City*:** In June 2008 NYSEG received a letter from subsidiaries of Edison Mission Energy regarding a notice of violation (NOV) from the U. S. Environmental Protection Agency (EPA) claiming that certain modifications to the Homer City Electric Generation Station (Homer City) during the time it was owned by NYSEG and Pennsylvania Electric Company (Penelec) were done in violation of EPA's new source review (NSR) regulations. Homer City was sold in 1999 to Edison Mission Energy by NYSEG and Penelec. Edison Mission Energy asserts that it is entitled to indemnification for certain fines, penalties and costs arising out of the violations alleged in the NOV under the terms of the Asset Purchase Agreement for Homer City. This appears to be the same claim Edison Mission Energy made to NYSEG and Penelec in October 2000. NYSEG continues to believe that the costs sought by Edison Mission Energy are not liabilities of NYSEG and that NYSEG did not retain liability for these material claims when the plant was sold.

In connection with this matter, on January 6, 2011, the U. S. Justice Department filed a lawsuit on behalf of the EPA in the U.S. District Court for the Western District of Pennsylvania against current and former owners and operators of Homer City. NYSEG and Penelec are named in the suit, along with EME Homer City Generation, the current operator, and eight limited liability companies who own the plant by virtue of a sale and leaseback refinancing that occurred in 2001. NYSEG believes it has a number of sound defenses to the claims included in the lawsuit, including that the statute of limitations and equitable principles prohibit EPA from forcing NYSEG to pay for costly improvements at a plant it has not owned or operated in over 10 years. NYSEG and all other defendants filed a motion to dismiss the complaint, which was granted by the judge on October 12, 2011. The EPA has appealed the decision. The judge's dismissal of the case bolsters our assessment that NYSEG does not face significant liability from this case. NYSEG, however, cannot predict the ultimate outcome of this matter.

***Merger order*:** The Iberdrola Merger Order contained a capital expenditure condition for NYSEG and RG&E for an aggregate of $540 million during 2009 and 2010. In September 2009 NYSEG and RG&E requested a limited waiver of the capital expenditure merger condition to allow them to spend the capital investment by 2011. The request was denied by the New York Public Service Commission (NYPSC) in its April 2010 Order. If NYSEG and RG&E were to spend less than the amount targeted in the merger order, they would be obligated to provide a calculation of the carrying charge revenue requirement effect resulting from the actual level of capital spending compared to the targeted amount, which could be returned to customers if ordered by the NYPSC.

NYSEG and RG&E made a filing in January 2011 in which they showed that NYSEG spent approximately $359 million in capital during 2009 and 2010, and RG&E spent approximately $188 million in capital during 2009 and 2010. As part of the same filing, they provided an assessment of other considerations, including the effects on customers associated with a lower level of capital spending during 2009, and provided reasons why the total revenue requirement effect, as calculated, should not be returned to customers.

The NYPSC issued an order in November 2011 that directed NYSEG to record a deferred credit amount of $6.8 million and directed RG&E to record a deferred credit amount of $10.0 million on behalf of customers due to the timing of the 2009 and 2010 capital expenditures. As required by the order, the deferred credits will not accrue any additional carrying charges prior to its ultimate disposition to ratepayers. Disposition of the credits will occur after the end of the existing rate plan (after 2013). The order also allowed NYSEG to reflect approximately $3.5 million per year, for a three year period beginning in 2011, of shareholder deferred carrying charges on certain capital expenditures.

In December 2011 NYSEG and RG&E filed a Petition for Rehearing of the NYPSC November Order, asking the NYPSC to reconsider the imposition of the carrying charge deferred credit, since NYSEG had spent above the targeted level during the 2009-2010 time period and since the benefits to ratepayers of RG&E’s deferred spending had not been considered in the NYPSC November 2011 Order. The companies cannot predict the NYPSC reaction to the Petition for Rehearing. In 2011 we recorded the deferred credits as regulatory liabilities in compliance with the November 2011 order.

***New England Transmission Owners Allowed Rate of Return*:** CMP’s transmission rates are determined by a tariff regulated by the FERC and administered by ISO-NE. Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, as well as return of and on investment in transmission assets. The FERC provides base return on equity (ROE) and additional incentive adders applicable to assets based upon vintage, voltage and other factors. Pursuant to a FERC incentive rate order, CMP is provided a 12.89% return on equity and allowed to include the construction work in process related to the MPRP in rates, subject to the an annual reconciliation.

In September 2011 the Massachusetts Attorney general and other state officials filed a complaint with the FERC that the ISO-NE base return on equity for transmission owners in New England is too high and should be lowered. CMP is a member of the New England Transmission Owners (NE-TOs). The current base ROE is 11.14%. The complaint requests that the FERC reduce the NE-TO’s allowed base ROE by 1.94% to a value of 9.2%. If this relief is granted, effective with the date of the complaint, CMP would be required to refund approximately $3 million of 2011 transmission revenue, plus applicable interest, to its wholesale and retail transmission customers. The NE-TOs disagree with the complaint, are requesting dismissal, and filed testimony supporting their position that the existing rate is reasonable. The FERC is expected to determine in 2012 if the complaint should be dismissed or pursued. We cannot predict the outcome of this proceeding.

***Nonutility generator power purchase contracts*:** We expensed approximately $74 million for NUG power in 2011 and $71 million in 2010. We estimate that our NUG power purchases will total $82 million in 2012, $76 million in 2013, $75 million in 2014, $76 million in 2015 and 2016.

***Nuclear entitlement power purchase contracts*:** In connection with our sales of -nuclear generating assets in 2001 and 2004, we entered into four entitlement contracts under which we purchase electricity at a fixed contract price. We expensed approximately $260 million for nuclear entitlement power in 2011 and $292 million in 2010. We estimate that our nuclear entitlement power purchases will be $193 million in 2012, $203 million in 2013, $87 million in 2014, $3 million in 2015 and $0 million in 2016.

***Storm Costs for CMP*:** Under its distribution service 2008 Alternative Rate Plan (ARP 2008), CMP is allowed to recover restoration costs for extraordinary storms meeting established qualification criteria. In 2011 we requested recovery of $17.4 million of storm restoration costs associated with two large storms in February 2010 and November 2010. Through a negotiated settlement, an increase in prices reflective of a 36-month recovery of the requested amount was allowed to become effective, subject to further review and potential refund or adjustment in the recovery period. The MPUC Staff have raised concerns regarding the qualification of the November storm as an extraordinary storm event, as well as the prudence of certain restoration costs incurred in the February storm.

On January 30, 2012, the Staff of the MPUC filed its bench analysis in this proceeding, supporting its position that the November 2010 storm did not qualify as an extraordinary storm event and that certain restoration costs incurred in the February 2010 storm should not be recovered. If the Staff’s position is ultimately upheld in total by the MPUC, CMP would need to refund approximately $5 million to its customers. We expect this proceeding to be completed by the end of June 2012. We cannot predict the outcome of this proceeding.

Note 10. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric and natural gas service.

The EPA and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at 24 waste sites. The 24 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 24 sites, 15 sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites, four are included in Maine’s Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and nine sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $1.1 million related to 12 of the 24 sites. We have paid remediation costs related to the remaining 12 sites, and do not expect to incur any additional liability. We have recorded an estimated liability of $4 million related to another 13 sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties. The ultimate cost to remediate the sites may be significantly more than the accrued amount. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us.

We have a program to investigate and perform necessary remediation at our 52 sites where gas was manufactured in the past. Eight sites are included in the New York State Registry, eight sites are included in the New York Voluntary Cleanup Program, three sites are part of Maine's Voluntary Response Action Program and of those, two sites are part of Maine's Uncontrolled Sites Program. We have entered into consent orders with various environmental agencies to investigate and, where necessary, remediate 44 of the 52 sites.

Our estimate for all costs related to investigation and remediation of the 52 sites ranges from $193 million to $387 million at December 31, 2011. Our estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $193 million at December 31, 2011, and $204 million at December 31, 2010. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis unless payments are fixed and determinable. Nearly all of our environmental liability accruals, which are expected to be paid through the year 2030, have been established on an undiscounted basis. Some of our operating utility subsidiaries have received insurance settlements during the last two years, which they accounted for as reductions to their related regulatory assets.

NYSEG sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) to recover environmental clean-up costs at 16 former manufactured gas plants. On July 11, 2011, the United States District Court for the Northern District of New York issued a decision and order in NYSEG's favor. Based upon past and future clean-up costs at the 16 sites in dispute, FirstEnergy will be required to pay NYSEG approximately $60 million if the decision, as written, is upheld on appeal. FirstEnergy appealed the decision to the Second Circuit Court of Appeals, a process estimated to take approximately one year to complete. On September 9, 2011, FirstEnergy paid NYSEG $29.7 million, representing their share of past costs ($26.5 million) and pre-judgment interest ($3.2 million). If FirstEnergy succeeds in overturning the decision, NYSEG must return that payment. Our opinion is that it is less than probable that we will have to refund any of the $29.7 million and we have not recorded a contingency for that amount. The payment has been recorded as a reduction in the regulatory asset for environmental remediation.

Note 11. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet.

The financial instruments we hold or issue are not for trading or speculative purposes.

Notes to Consolidated Financial Statements

Commodity price risk: Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging activities.

NYSEG and RG&E currently have a nonbypassable wires charge adjustment that allows them to pass through rates any changes in the market price of electricity. They use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2011, the loss recognized in regulatory assets was $24.3 million for electricity derivatives. For the year ended December 31, the gain (loss) reclassified from regulatory assets into income, which is included in electricity purchased, was $(3.6) million for 2011 and $5.6 million for 2010.

All of our natural gas utilities have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. NYSEG and RG&E use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2011, the loss recognized in regulatory assets was $12.2 million for natural gas hedges. For the year ended December 31, the (loss) reclassified from regulatory assets into income, which is included in natural gas purchased, was $(14.7) million for 2011 and $(21.8) million for 2010.

Energetix, Inc. and NYSEG Solutions, Inc. offer retail electric and natural gas service to customers in New York State and actively hedge the load required to serve customers that have chosen them as their commodity supplier. As of January 3, 2012, the energy marketing subsidiaries' expected fixed price loads were 96% hedged for 2012. A fluctuation of $1.00 per Megawatt-hour in the average price of electricity would change earnings less than $87 thousand in 2012. The percentage of hedged load for the energy marketing subsidiaries is based on load forecasts, which include certain assumptions such as historical weather patterns. Actual results could differ as a result of changes in the load compared to the load forecast.

Those two companies designate financial electricity contracts as cash flow hedging instruments. We record changes in the fair value of the cash flow hedging instruments in other comprehensive income (OCI), to the extent they are considered effective, and reclassify those gains or losses into earnings in the same period or periods during which the hedged transactions affect earnings. We record the ineffective portion of any change in fair value of cash flow hedges to the income statement as either Other (Income) or Other Deductions, as appropriate.

Our derivative volumes by commodity type that are expected to settle each year are:

Year to settle	Electricity Contracts Financial Mwhs	Natural Gas Contracts Financial Dths	Other Fuel Contracts Financial Gals
As of December 31, 2011			
2012	5,666,658	8,739,632	1,748,500
2013	1,505,770	999,068	-
2014	5,138	-	-
As of December 31, 2010			
2011	4,652,994	16,983,245	1,569,200
2012	1,146,240	1,532,202	-
2013	-	10,164	-

The location and amounts of derivative fair values in the balance sheet are:

As of December 31,	Asset Derivatives Balance Sheet Location	Asset Derivatives Fair Value	Liability Derivatives Balance Sheet Location	Liability Derivatives Fair Value
(Thousands)				
Derivatives designated as hedging instruments				
2011				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	**-**	Current liabilities	**$(25,876)**
Long-term	Other assets	**$158**	Other liabilities	**(7,431)**
Natural gas derivatives:				
Current	Current assets	**-**	Current liabilities	**(13,746)**
Long-term	Other assets	**-**	Other liabilities	**(915)**
Other contracts:	Current assets	**-**	Current liabilities	**(615)**
Total		**$158**		**$(48,583)**
2010				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	$9,829	Current liabilities	$(234)
Long-term	Other assets	400	Other liabilities	(370)
Natural gas derivatives:				
Current	Current assets	-	Current liabilities	(13,117)
Long-term	Other assets	18	Other liabilities	(57)
Other contracts:	Current assets	95	Current liabilities	-
Total		$10,342		$(13,778)

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The effect of hedging instruments on OCI and income was:

Year Ended December 31,	Gain (Loss) Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain (Loss) Reclassified from Accumulated OCI into Income	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives
Derivatives in Cash Flow Hedging Relationships	**Effective Portion (1)**	**Effective Portion (1)**		**Ineffective Portion and Amount Excluded from Effectiveness Testing (2)**	
(Thousands)					
2011					
Interest rate contracts	**-**	Interest expense	**$(9,329)**	Interest expense	**-**
Commodity contracts:					
Electricity derivatives	**$(22,561)**	Electricity purchased	**5,017**	Other (Income)/ Other Deductions	**$120**
Natural gas	**277**	Natural gas purchased	**(2,399)**	-	**-**
Other	**20**	Other direct costs	**(730)**	-	**-**
Total	**$(22,264)**		**$(7,441)**		**$120**
2010					
Interest rate contracts	-	Interest expense	$(9,035)	Interest expense	-
Commodity contracts:					
Electricity derivatives	$7,921	Electricity purchased	(11,304)	Other (Income)/ Other Deductions	$(136)
Natural gas	3,390	Natural gas purchased	(3,549)	-	**-**
Other	206	Other direct costs	59	-	-
Total	$11,517		$(23,829)		$(136)

(1) Changes in OCI are reported in after-tax dollars.
(2) Ineffective portion of long-term power supply contracts that are designated as cash flow hedges.

The amount in OCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2011, is a net loss of $130.3 million as compared to a net loss of $139.7 million for 2010. As of December 31, 2011, we reported $9.3 million in net derivative losses related to discontinued cash flow hedges.

At December 31, 2011, $12.1 million in losses are reported in OCI because the forecasted transaction is considered to be probable. We expect that those losses will be reclassified into earnings within the next 34 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions.

NYSEG, RG&E and our unregulated energy marketing subsidiaries Energetix, Inc. and NYSEG Solutions, Inc., face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally

Moody's or S&P). When our exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract. For financial statement presentation, we do not offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement. Under the master netting arrangements our obligation to return cash collateral was $1.5 million at December 31, 2011, and December 31, 2010.

Certain of our derivative instruments contain provisions that require us to maintain an investment grade credit rating on our debt from each of the major credit rating agencies. If our debt were to fall below investment grade, it would be in violation of those provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2011, is $48.6 million for which we have posted collateral of $32 million in the normal course of business. If the credit-risk-related contingent features underlying those agreements were triggered on December 31, 2011, we would be required to post an additional $16.6 million of collateral with our counterparties.

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The carrying amounts and estimated fair values of our financial instruments are shown in the following table. Carrying amounts include related debt premiums and discounts.

December 31,	**2011**		**2010**	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
(Thousands)				
First mortgage bonds	**$989,004**	**$1,209,021**	$774,952	$836,830
Pollution control notes, fixed	**$341,554**	**$345,210**	$367,443	$363,084
Pollution control notes, variable	**$168,025**	**$148,415**	$168,200	$146,931
Various long-term debt	**$876,434**	**$1,038,957**	$902,258	$914,731
Long-term debt owed to affiliates	**$650,000**	**$758,710**	$650,000	$725,834

The carrying amounts for cash and cash equivalents, accounts receivable, notes payable and interest accrued approximate their estimated fair values.

We value all fixed rate long-term debt, whether unsecured or secured by a first mortgage lien, taxable or tax-exempt, by assigning a market-based yield for each security and then deriving the price from the yield. Market-based yields are determined by observing secondary market trading levels for debt of similar maturity, rating, tax and structural characteristics. We value all variable rate debt at par as it approximates fair value, except for the auction rate securities issued by RG&E, which do not have an active market.

Notes to Consolidated Financial Statements

Assets and liabilities measured at fair value on a recurring basis

		Fair Value Measurements at December 31, Using		
Description	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2011				
Assets				
Noncurrent investments available for sale, auction rate securities	**$2,700**	**-**	**-**	**$2,700**
Noncurrent investments available for sale, other	**39,558**	**$39,558**	**-**	**-**
Derivatives				
Commodity contracts				
Electricity	**158**	**-**	**-**	**158**
Total	**$42,416**	**$39,558**	**-**	**$2,858**
Liabilities				
Derivatives				
Commodity contracts:				
Electricity	**$33,307**	**$24,153**	**-**	**$9,154**
Natural gas	**14,661**	**14,661**	**-**	**-**
Other	**615**	**-**		**615**
Total	**$48,583**	**$38,814**	**-**	**$9,769**
2010				
Assets				
Noncurrent investments available for sale, auction rate securities	$2,700	-	-	$2,700
Noncurrent investments available for sale, other	44,520	$44,520	-	-
Derivatives				
Commodity contracts:				
Electricity	10,230	1,431	-	8,799
Natural gas	18	18	-	-
Other	94	-	-	94
Total	$57,562	$45,969	-	$11,593
Liabilities				
Derivatives				
Commodity contracts:				
Electricity	$604	$370	-	$234
Natural gas	13,174	13,174	-	-
Total	$13,778	$13,544	-	$234

We had no significant transfers to or from Level 1 and 2 during the years ended December 31, 2010 and 2011. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our noncurrent investments available for sale, auction rate securities based on the estimated probabilities of when the auction rate markets would return to historic interest rate levels and include the measurements in Level 3. (See Note 1.)

We measure the fair value of our noncurrent investments available for sale, other using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments primarily consist of money market funds, but also include some fixed income and equity investments.

We determine the fair value of our various derivative assets and liabilities utilizing market approach valuation techniques:

- NYSEG, RG&E and our energy marketing subsidiaries enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. NYSEG and RG&E hedge their electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. NYSEG and RG&E hedge all of their electric load obligations in a NYISO location where an active market exists. The forward market prices used to value their open electric energy derivative contracts are readily available with no adjustment required and we include the fair value in Level 1. Our energy marketing subsidiaries enter into hedges for some NYISO locations where forward market price quotes are not actively traded and not readily available outright from market dealers. We derive forward market prices for those instruments based on the historical relationship of prices in those locations to prices in locations where an active market exists. The resulting value represents the derived forward market price for each location, which we use to value the open derivative contracts. Because we adjust the quoted market prices for the energy marketing subsidiaries' load characteristics, we include the fair values in Level 3.
- NYSEG, RG&E and our energy marketing subsidiaries enter into natural gas derivative contracts to hedge the forecasted purchases required to serve their natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.

Instruments measured at fair value on a recurring basis using significant unobservable inputs

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Auction Rate Securities	**Derivatives, Net**	**Total**
Balance, January 1, 2010	$2,735	$4,925	$7,660
Total (losses) gains (realized/unrealized)			
Included in earnings	(35)	20,297	20,262
Included in other comprehensive income	-	(13,700)	(13,700)
Purchases	-	(2,863)	(2,863)
Balance, December 31, 2010	2,700	8,659	11,359
Total (losses) gains (realized/unrealized)			
Included in earnings	**-**	**4,407**	**4,407**
Included in other comprehensive income	**-**	**(22,541)**	**(22,541)**
Purchases	**-**	**(136)**	**(136)**
Balance, December 31, 2011	**$2,700**	**$(9,611)**	**$(6,911)**
Total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at December 31,			
2010	-	-	-
2011	**-**	**$120**	**-**

The gains and losses included in earnings for the period (above), which are reported in the various categories indicated are:

	Electricity purchased	**Other operating expense**	**Other Income**	**Other Deductions**	**Interest expense**
(Thousands)					
Total gains (losses) included in earnings for year ended December 31,					
2010	$7,956	$3,305	-	$(35)	$9,036
2011	**$5,017**	**$(730)**	**$120**	**-**	**-**

Asset measured at fair value on a nonrecurring basis

		Fair Value Measurement Using			
Description	**At December 31, 2011**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total Loss Year Ended December 31, 2011**
(Thousands)					
Long-lived asset held and used					
Carthage generating station	**$4,889**	**-**	**-**	**$4,889**	**$(2,723)**

In accordance with the provisions for impairment of long-lived assets, the Carthage generating station that is held and used by Cayuga Energy, Inc. was written down to its fair value of $4.9 million, resulting in an impairment loss of $2.7 million, which was included in earnings for the period.

Valuation technique: We determined the fair value of the Carthage generating station using an income approach – based on discounted cash flows – and included the measurement in Level 3. On an undiscounted basis there would be no impairment if we continued to assume that the plant would be held throughout its life. However, because we now assume that the plant will be sold (see Note 17), we discounted the cash flows as a proxy for the auction value of the plant. The key assumption is the projected capacity values, which have declined significantly since 2009 and are currently well below the cost of new capacity. The lower values, which are based on market quotes, are expected to last through 2014. There are no reliable forecasts for capacity values for years beyond 2014. During 2011 we developed internally various capacity value forecasts. Those forecasts attempt to reflect such factors as the marginal cost of new capacity and the anticipated shutdowns of major plants, which should increase capacity values. Because no forecast was more reasonable, we used a simple average of the forecasts. Other assumptions have less of an effect on the final results such as the amount of actual generation, which has varied significantly in the past but has little effect because of the very low margin resulting from those sales.

Notes to Consolidated Financial Statements

Note 13. Accumulated Other Comprehensive Income (Loss)

(Thousands)	Balance January 1, 2010	2010 Change	Balance December 31, 2010	2011 Change	Balance December 31, 2011
Net unrealized holding (losses) on investments, net of income tax (expense) benefit of $(70) for 2010 and $209 for 2011	-	$(45)	$(45)	**$(164)**	**$(209)**
Amortization of pension cost for nonqualified plans, net of income tax (expense) of $(769) for 2010 and $(889) for 2011	(9,995)	1,177	(8,818)	**1,126**	**(7,645)**
Unrealized gains (losses) on derivatives qualified as hedges:					
Unrealized gains during period on derivatives qualified as hedges, net of income tax (expense) benefit of $(22,638) for 2010 and $4,611 for 2011		41,345		**(14,960)**	
Reclassification adjustment for (gains) included in net income, net of income tax expense of $24,007 for 2010 and $273 for 2011		(36,558)		**(411)**	
Net unrecognized gains on settled cash flow treasury hedges, net of income tax benefits of $(3,726) for 2010 and $(3,775) for 2011		5,603		**5,554**	
Net unrealized (losses) gains on derivatives qualified as hedges	(86,731)	10,390	(76,341)	**(9,817)**	**(86,158)**
Accumulated Other Comprehensive (Loss) Gain Income	$(96,726)	$11,522	$(85,204)	**$(8,855)**	**$(94,012)**

No Accumulated Other Comprehensive Income (Loss) Gain is attributable to the noncontrolling interests for the above periods.

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Note 14. Retirement Benefits

We have funded noncontributory defined benefit pension plans that cover substantially all of our employees. The plans provide defined benefits based on years of service and final average salary. We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

***Obligations and funded status*:**

	Pension Benefits		Postretirement Benefits	
	2011	**2010**	**2011**	**2010**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$2,206,420**	$2,333,547	**$471,412**	$529,945
Service cost	**28,766**	34,092	**4,727**	5,299
Interest cost	**106,738**	131,562	**22,892**	27,679
Plan participants' contributions	**-**	-	**10,064**	10,957
Curtailments	**-**	1,134	**-**	-
Plan amendments	**-**	10,886	**(48)**	(21,446)
Special termination benefits	**1,435**	37,351	**-**	-
Actuarial loss(gain)	**112,123**	166,733	**5,725**	22,442
Benefits paid	**(137,566)**	(158,769)	**(44,732)**	(49,482)
Federal subsidy on benefits paid	**-**	-	**3,178**	3,100
Disposition of obligations related to sale of natural gas companies	**-**	(350,116)	**-**	(57,082)
Benefit obligation at December 31	**$2,317,916**	$2,206,420	**$473,218**	$471,412
Change in plan assets				
Fair value of plan assets at January 1	**$2,151,199**	$2,253,753	**$147,998**	$146,309
Actual return on plan assets	**3,583**	262,786	**(8,611)**	18,123
Employer contributions	**29,577**	30,430	**37,667**	36,030
Plan participants' contributions	**-**	-	**10,064**	14,057
Benefits paid	**(137,566)**	(158,769)	**(44,731)**	(49,482)
Withdrawal from VEBA	**-**	-	**(33,813)**	-
Disposition of assets related to sale of natural gas companies	**-**	(237,001)	**-**	(17,039)
Fair value of plan assets at December 31	**$2,046,793**	$2,151,199	**$108,574**	$147,998
Funded status at December 31	**$(271,123)**	$(55,221)	**$(364,644)**	$(323,414)

Amounts recognized in the balance sheet	Pension Benefits		Postretirement Benefits	
December 31,	**2011**	**2010**	**2011**	**2010**
(Thousands)				
Noncurrent assets	**-**	$87,336	**-**	-
Current liabilities	**-**	-	**$(6,995)**	$(6,545)
Noncurrent liabilities	**$(271,123)**	(142,557)	**(357,649)**	(316,869)
	$(271,123)	$(55,221)	**$(364,644)**	$(323,414)

The change in benefit obligation and change in plan assets activity above reflect activity and the related decreases in the obligation and assets for the natural gas companies through November 16, 2010 (see Note 2). The amounts shown above for the disposition related to the sale of the natural gas companies were based on a roll forward of expenses, including amortization of gains and losses, for the period through November 16, 2010. Those plans were not remeasured as of the date of sale because the natural gas companies received regulatory recovery of net periodic benefit costs through rates. Therefore, the sale of the natural gas companies did not result in gains or losses that should be recognized in our statement of operations.

Notes to Consolidated Financial Statements

The 2010 results also reflect several actions taken at our electric operating companies. A Voluntary Early Retirement Program (VERP) was offered during 2010, resulting in one-time charges for special termination benefits and a one-time curtailment loss for CMP's Union Plan. NYSEG extended a retirement supplement, effective July 1, 2010, applicable to union employees who retire after age 59 between July 1, 2010, and June 30, 2015; the supplement was first effective July 1, 2005, and applied to retirements between July 1, 2005, and June 30, 2010. During 2010 CMP made changes to its retiree medical plan benefits for its union employees that include a cap on its contribution to the postretirement medical plans for employees who retire on or after July 1, 2013.

In August 2011 RG&E offered a voluntary early retirement program (VERP) to qualifying union employees. The 27 employees who accepted the VERP will receive forms of enhanced pension benefits. In 2011 we recorded costs totaling approximately $1.4 million for the VERP, which will be paid from RG&E's pension plan.

We have determined that all of our operating companies are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities consist of:

	Pension Benefits		Postretirement Benefits	
December 31,	**2011**	**2010**	**2011**	**2010**
(Thousands)				
Net loss	**$1,023,676**	$812,113	**$61,869**	$47,970
Prior service cost (credit)	**$25,498**	$29,630	**$(13,882)**	$(19,796)
Transition obligation	**-**	-	**$6,800**	$13,600

Our accumulated benefit obligation for all defined benefit pension plans was $2.1 billion at December 31, 2011, and 2010.

CMP's and NYSEG's postretirement benefits were partially funded at December 31, 2011 and December 31, 2010. In 2011, NYSEG withdrew $33 million from its postretirement benefit fund to pay for a portion of 2011 post retirement costs.

The projected benefit obligation exceeded the fair value of pension plan assets for all plans as of December 31, 2011; and for the CMP and RG&E plans as of December 31, 2010. The accumulated benefit obligation exceeded the fair value of pension plan assets for the CMP and RG&E plans as of December 31, 2011; and for the CMP plan as of December 31, 2010. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for those companies' plans for the relevant periods.

	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets	
December 31,	**2011**	**2010**	**2011**	**2010**
(Thousands)				
Projected benefit obligation	**$2,317,916**	$785,851	**$807,066**	$331,295
Accumulated benefit obligation	**$2,170,784**	$725,962	**$744,509**	$300,039
Fair value of plan assets	**$2,046,793**	$643,294	**$618,140**	$210,564

***Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities*:**

	Pension Benefits		Postretirement Benefits	
Year ended December 31,	**2011**	**2010**	**2011**	**2010**
(Thousands)				
Net periodic benefit cost				
Service cost	**$28,766**	$34,092	**$4,727**	$5,299
Interest cost	**106,738**	131,562	**22,892**	27,679
Expected return on plan assets	**(195,481)**	(216,699)	**(7,375)**	(7,986)
Amortization of prior service cost (benefit)	**4,802**	3,507	**(5,962)**	(9,124)
Amortization of net loss	**92,458**	76,910	**7,811**	4,855
Special termination benefit charge	**1,435**	37,351	**-**	-
Curtailment charge	**-**	1,134	**-**	-
Amortization of transition obligation	**-**	-	**6,800**	6,800
Net periodic benefit cost	**$38,718**	$67,857	**$28,893**	$27,523
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	**$304,021**	$145,750	**$21,711**	$12,305
Prior service cost (benefit)		2,393	**5,962**	(21,446)
Amortization of net (loss)	**(92,457)**	(76,910)	**(7,811)**	(4,855)
Current year prior service cost	**-**	7,819	**(48)**	-
Amortization of prior service (cost) credit	**(4,802)**	(3,503)	**-**	9,124
Disposition of obligations related to sale of natural gas companies	**-**	(34,698)	**-**	(7,918)
Amortization of transition obligation	**-**	-	**(6,800)**	(6,800)
Total recognized in regulatory assets and regulatory liabilities	**206,761**	40,851	**13,014**	(19,590)
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$245,479**	$108,708	**$41,907**	$7,933

Net periodic benefit costs above include amounts related to the gas companies that were sold in 2010	**Pension Benefits**	**Postretirement Benefits**
(Thousands)		
January 1 through November 16, 2010	$10,630	$2,703

We include the net periodic benefit cost in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents. The amount of postretirement benefit cost deferred at December 31 was $10 million for 2011 and $12 million for 2010. We expect to recover any deferred postretirement costs in 2012. We are amortizing over 20 years the transition obligation for postretirement benefits that resulted from our adoption in 1992 of the accounting requirements concerning employers' accounting for postretirement benefits other than pensions.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2012	**Pension Benefits**	**Postretirement Benefits**
(Thousands)		
Estimated net loss	$109,602	$5,742
Estimated prior service cost	$4,579	$(5,967)
Estimated transition obligation	-	$6,800

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ended December 31, 2012.

Weighted-average assumptions used to determine benefit obligations at December 31,	**Pension Benefits 2011**	**Pension Benefits 2010**	**Postretirement Benefits 2011**	**Postretirement Benefits 2010**
Discount rate	**4.75%**	5.00%	**4.75%**	5.00%
Rate of compensation increase	**4.00%**	4.00%	**4.00%**	4.00%

As of December 31, 2011, we reduced our discount rate from 5.00% to 4.75%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade noncallable bonds with above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for year ended December 31,	**Pension Benefits 2011**	**Pension Benefits 2010**	**Postretirement Benefits 2011**	**Postretirement Benefits 2010**
Discount rate	**5.00%**	5.80%	**5.00%**	5.80%
Expected long-term return on plan assets	**8.75%**	8.75%	**-**	-
Expected long-term return on plan assets - nontaxable trust	**-**	-	**8.00%**	8.00%
Expected long-term return on plan assets - taxable trust	**-**	-	**4.80%**	4.80%
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. The operating companies amortize unrecognized actuarial gains and losses either over 10 years from the time they are incurred or using the standard amortization methodology, under which amounts in excess of 10% of the greater of the projected benefit obligation or market-related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates to determine benefit obligations at December 31,	**2011**	**2010**
Health care cost trend rate assumed for next year	**7.8%**	7.8%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**4.5%**	4.5%
Year that the rate reaches the ultimate trend rate	**2028**	2028

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

	1% Increase	**1% Decrease**
(Thousands)		
Effect on total of service and interest cost	**$555**	**($550)**
Effect on postretirement benefit obligation	**$14,574**	**($13,582)**

Plan assets**:** Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

Our asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets of 56% equity securities, 30% fixed income and 14% for all other types of investments. The target allocations within allowable ranges are further diversified into 28% large cap domestic equities, 7% medium and small cap domestic equities, 5% emerging markets, and 16% international equity securities. Fixed income investment targets and ranges are segregated into long dated corporate securities 17%, annuity contracts 5%, and 25 year zero coupon bonds 8%. All fixed income investments are in domestic securities. Other, alternative investment targets are 4% for real estate, and 10% for absolute return and strategic markets. Systematic rebalancing within the target ranges, should any asset categories drift outside their specified ranges, increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

The fair values of our pension benefits plan assets at December 31, 2011 and 2010, by asset category are:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2011				
Cash and cash equivalents	**$59,220**	**-**	**$59,220**	**-**
U.S. government securities	**110,250**	**$110,250**	**-**	**-**
Common stocks	**864,801**	**614,330**	**250,471**	**-**
Registered investment companies	**108,340**	**108,340**	**-**	**-**
Corporate bonds	**277,432**	**137**	**277,295**	**-**
Preferred stocks	**2,945**	**2,945**	**-**	
Common/collective trusts	**320,898**	**-**	**56,885**	**$264,013**
Partnership/joint venture interests	**50,928**	**-**	**-**	**50,928**
Real estate investments	**52,298**	**-**	**-**	**52,298**
Other investments, principally annuity and fixed income	**199,681**	**22,421**	**1,743**	**175,517**
Total	**$2,046,793**	**$858,423**	**$645,614**	**$542,756**
2010				
Cash and cash equivalents	$49,214	$734	$48,480	-
U.S. government securities	52,122	52,122	-	-
Common stocks	1,036,468	749,565	286,903	-
Registered investment companies	85,923	85,923	-	-
Corporate bonds	183,186	-	183,186	-
Preferred stocks	7,039	7,039	-	-
Common/collective trusts	351,408	-	76,476	$274,932
Partnership/joint venture interests	96,624	-	-	96,624
Real estate investments	45,374	-	-	45,374
Other investments, principally annuity and fixed income	243,841	21,817	31,712	190,312
Total	$2,151,199	$917,200	$626,757	$607,242

Notes to Consolidated Financial Statements

Valuation techniques: We value our pension benefits plan assets as follows:

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities, Common stocks and Registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common/collective trusts and Partnership/joint ventures – using the Net Asset Value (NAV) provided by the administrator of the fund. The NAV is based on the value of the underlying assets owned by the fund, minus its liabilities, and then divided by the number of shares outstanding. The NAV is classified as Level 2 if the plan has the ability to redeem the investment with the investee at NAV per share at the measurement date. Redemption restrictions or adjustments to NAV based on unobservable inputs result in the fair value measurement being classified as Level 3 if those inputs are significant to the overall fair value measurement.
- Real estate investments – based on a discounted cash flow approach that includes the projected future rental receipts, expenses and residual values because the highest and best use of the real estate from a market participant view is as rental property.
- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)				
(Thousands)	**Common/ Collective Trusts**	**Partner-ship/ Joint Venture Interests**	**Real Estate Invest-ments**	**Other Invest-ments**	**Total**
Balance, December 31, 2009	$295,644	$93,269	$40,618	$131,124	$560,655
Actual return on plan assets:					
Relating to assets still held at the reporting date	4,678	-	-	110	4,788
Relating to assets sold during the year	41,218	3,207	4,163	510	49,098
Purchases, sales and settlements	(66,608)	148	593	58,568	(7,299)
Transfers into and/or out of Level 3	-	-	-	-	-
Balance, December 31, 2010	274,932	96,624	45,374	190,312	607,242
Actual return on plan assets:					
Relating to assets still held at the reporting date	**(12,053)**	**(10,335)**	**3,832**	**(908)**	**(19,464)**
Relating to assets sold during the year	**2,377**	**8,052**	**-**	**2**	**10,431**
Purchases, sales and settlements	**(1,243)**	**-**	**3,092**	**(13,889)**	**(12,040)**
Transfers into and/or out of Level 3	**-**	**(43,413)**	**-**	**-**	**(43,413)**
Balance, December 31, 2011	**$264,013**	**$50,928**	**$52,298**	**$175,517**	**$542,756**

Notes to Consolidated Financial Statements

Our postretirement benefits plan assets are held with two trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes in order to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 23% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes. The remainder is invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for our postretirement benefits plan assets of 56% equity securities, 37% fixed income and 7% for all other types of investments. The target allocations within allowable ranges are further diversified into 30% large cap domestic equities, 7% medium and small cap domestic equities, 13% international developed market and 6% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 30%, global high yield fixed income 4% and international developed market debt 3%. Other, alternative investment targets are 4% for real estate and 3% absolute return. Systematic rebalancing within target ranges, should any asset categories drift outside their specified ranges, increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

The fair values of our other postretirement benefits plan assets at December 31, 2011 and 2010, by asset category are:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2011				
Money market funds	**$2,858**	**$2,858**	**-**	**-**
Mutual funds, fixed	**43,614**	**43,614**	**-**	**-**
Mutual funds, equity	**57,895**	**57,895**	**-**	**-**
Mutual funds, other	**4,207**	**4,207**	**-**	**-**
Total assets measured at fair value	**$108,574**	**$108,574**	**-**	**-**
2010				
Money market funds	$7,907	$7,907	-	-
Mutual funds, fixed	49,100	49,100	-	-
Mutual funds, equity	90,964	90,964	-	-
Other investments	27	27	-	-
Total assets measured at fair value	$147,998	$147,998	-	-

Valuation techniques: We value our postretirement benefits plan assets as follows:

- Money market funds and Mutual funds, fixed and equity – based upon quoted market prices, which represent the NAV of the shares held.
- Other investments – these are primarily 401(h) investments that are an allocation of pension Master Trust investments.

Diversified equity securities did not include any Iberdrola common stock at December 31, 2011.

Cash Flows

Contributions**:** In accordance with our funding policy we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $18 million to our pension benefit plans and $3 million to our other postretirement benefit plans in 2012.

Estimated future benefit payments**:** Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2012	$144,066	$39,121	$3,608
2013	$149,398	$39,500	$3,924
2014	$152,325	$40,017	$4,241
2015	$155,249	$40,399	$4,532
2016	$159,836	$40,567	$4,802
2017 - 2021	$811,641	$202,794	$27,345

Note 15. NYSEG and RG&E Rate Proceedings

On September 16, 2010, the NYPSC approved a new rate plan for electric and natural gas service provided by the companies effective August 26, 2010, through December 31, 2013. Major provisions of the plan include:

- Approximate delivery rate increases as follows (in millions of dollars):

Rate year ending August 31,	NYSEG Electric	NYSEG Natural Gas	RG&E Electric	RG&E Natural Gas
2011	$16.4 (2.5%)	$9.9 (6.0%)	$15.6 (4.1%)	$10.9 (8.0%)
2012	$27.8 (4.2%)	$10.3 (5.8%)	$10.2 (2.6%)	$10.9 (7.3%)
2013	$29.3 (4.3%)	$10.5 (5.6%)	$13.2 (3.2%)	$11.0 (6.9%)

- The delivery rate increases were moderated and levelized through the use of $311 million in positive benefits adjustments (PBAs), including $36 million of carrying costs, that were required and set aside for the benefit of ratepayers when Iberdrola, S.A. acquired NYSEG and RG&E in 2008. The PBAs will be utilized as follows: in September 2010 a one-time write-off of $82.5 million, which is offset by write-offs of deferred storm costs of $76.4 million, $6.1 million in property tax and amortizations during the rate years ended August 31 of: $88.0 million in 2011, $54.4 million in 2012 and $26.9 million in 2013; and $8.5 million in the four months ended December 31, 2013. The balance of $50.2 million will be amortized at a later time.
- Rates were set to allow for the recovery, over the 40 months of the rate plan, of regulatory assets of $126.0 million net of regulatory liabilities.
- The recovery includes $32.4 million for the cost to achieve efficiency initiatives through workforce reductions (see Note 1). The rate increases were moderated with $19.2 million in annual net savings from workforce reduction and related labor cost-cutting initiatives, as well as a one percent annual productivity adjustment.
- To resolve a number of disputed items related to the annual compliance filings, including the calculation of earnings sharing accruals, NYSEG reduced its environmental reserve by $23 million and its deferred storm costs by $4 million, and added $6 million to the Asset Sale Gain Account (ASGA). RG&E absorbed $20 million of prior loss from interest rate hedges and added $6.5 million to the ASGA. In December 2009 NYSEG established a reserve of $30

million and RG&E established a reserve of $10 million for those contingencies, which were reversed as a result of the rate decision.

- The revenue requirements are based on a 10% allowed ROE applied to an equity ratio of 48 percent. Beginning in 2011, if earnings exceed the allowed return, a tiered earnings sharing mechanism (ESM) will capture a portion of the excess for the benefit of ratepayers. The ESM is subject to specified downward adjustments if the companies fail to meet certain reliability and customer service measures.
- Key components of the rate plan include electric reliability performance mechanisms, natural gas safety performance measures, customer service quality metrics and targets, and electric distribution vegetation management programs that establish threshold performance targets. There will be downward revenue adjustments if the companies fail to meet the targets.
- Low-income program budgets have been increased to approximately $19.2 million. All home energy assistance program recipients will be eligible for the program.
- New revenue decoupling mechanisms (RDMs), intended to remove company disincentives to promote increased energy efficiency were established. Under the RDMs, electric revenues are based on revenue per customer class rather than billed revenue, while natural gas revenues are based on revenue per customer. Any shortfalls (excesses) between billed revenues and allowed revenues will be accrued for future recovery (refund).

Under the merger order prescribed by the NYPSC, NYSEG and RG&E customers were to receive $275 million in PBAs. Those benefits were to be used, over time, to either reduce rates or moderate requested rate increases. Conditions were also established to ensure that ratepayers receive a portion of any added benefits associated with synergy savings and efficiency gains produced by the transaction. We recorded the PBAs in September 2008, in accordance with the merger order, as a regulatory liability with an offsetting charge to income, and accrued a carrying cost at the pretax rate allowed by the NYPSC until used for the benefit of customers. Carrying costs, which are included in interest expense, were $13 million in 2010 and $18 million in 2009.

As part of the rate plan, the companies offset the PBAs and other regulatory liabilities against certain regulatory assets. In addition, the companies established a regulatory asset to allow recovery of the special termination benefits and severance costs associated with workforce reductions (see Note 1), and wrote off some undepreciated fixed assets and reversed a reserve established in December 2009. The effects on 2010 net income of the various adjustments to regulatory assets and regulatory liabilities are:

Description	**Income Statement Line Item**	**Increase (Decrease) in Net Income**
(Millions)		
Elimination of annual compliance filing reserve regulatory liability	Electric operating revenue	$40.0
ASGA	Electric operating revenue	(6.5)
Interim period adjustment	Electric operating revenue	2.8
	Total Electric Operating Revenue	36.3
Elimination of PBA regulatory liability	Other operating expenses	82.4
Elimination of storm costs regulatory assets	Maintenance	(81.4)
Elimination of environmental reserve regulatory asset	Other operating expenses	(23.0)
Establishment of cost to achieve efficiency regulatory asset*	Other operating expenses	32.9
Elimination of property taxes	Other taxes	(5.1)
	Net effects of new rate case on operating and maintenance	5.8
Property, plant and equipment	Depreciation and amortization	(10.8)
	Total Operating Expenses	(5.0)
	Income Before Income Taxes	31.3
Income tax effect	Income Taxes	(12.4)
	Net Income	$18.9

*Relates to the recovery of special termination benefit costs (see Note 1).

Beginning on August 26, 2010, NYSEG will amortize $15.2 million per year of a theoretical excess depreciation reserve of $303.9 million; and beginning on September 1, 2012, RG&E will amortize $5.25 million per year of its theoretical excess depreciation reserve of $105 million. Both amortization amounts reflect a 20-year amortization period. Theoretical excess depreciation is the difference between actual accumulated depreciation taken to date and a theoretical reserve. The actual accumulated depreciation is the result of depreciation rates allowed in prior rate orders based on estimates of useful lives and net salvage values as determined in those cases. The theoretical reserve is the amount that would have accumulated if the depreciation rates in the new rate plan had been in place for the entire useful lives of the affected assets. Differences between the actual reserve and the theoretical reserve are normal aspects of utility ratemaking. The usual treatment is to flow any excess or deficiency back as an adjustment to depreciation expense over the remaining life of the property. However, in accordance with the new rate plan, NYSEG and RG&E will moderate electric rates by recording the theoretical reserve amortization as a debit to accumulated depreciation and a credit to other revenues, and normalize the amortization from a tax perspective.

Note 16. Sale of NYSEG's Seneca Lake Storage Facility

In January 2010 NYSEG entered into an agreement to sell its Seneca Lake Storage facility and related assets for $65 million. The carrying amount of the facility assets is separately stated on the balance sheet as of December 31, 2010, and was approximately $33 million. The sale of the facility was made contingent on receiving appropriate regulatory approvals from the NYPSC. The FERC issued an order on August 26, 2010, authorizing the parties to proceed with the transaction, subject to compliance requirements that the buyer was required to attend to but that would not delay the closing. The NYPSC issued an order on March 4, 2011, approving the transaction, but included several conditions in the order, which were met by NYSEG. The sale was completed on July 13, 2011.

In the third quarter of 2011 NYSEG recognized a gain of $32 million on the sale of the Seneca Lake Storage facility of which $20 million was recorded as a regulatory liability in compliance with the NYPSC order to return part of the gain to ratepayers and the remaining $12 million was recorded to other income.

Note 17. Sale of Fossil Fuel Generation Assets

Iberdrola, in connection with receiving authorization from the NYPSC in September 2008 to acquire Energy East, agreed to sell certain fossil fuel generation assets owned by either RG&E or Cayuga Energy, Inc. (Cayuga). In its order authorizing the acquisition, the NYPSC directed Iberdrola and the other petitioners in the acquisition proceeding to develop, in collaboration with interested parties, a divestiture plan for the fossil fuel generation assets. Iberdrola and Energy East filed the divestiture plan with the NYPSC in November 2008. The NYPSC issued an order approving the divestiture plan as filed, effective November 17, 2009.

The divestiture plan required the generation assets to be sold at auction in a two-stage process, as well as extensive consultation with the NYPSC Staff concerning the auction process. The auction process would be suspended, but not terminated, if bids obtained were priced at less than the current net book value of the assets (approximately $14 million at December 31, 2009). We would then petition the NYPSC for guidance on the next steps to be taken. In December 2010 we filed a petition with the NYPSC for permission to terminate the auction process. As a result of the unsuccessful auction process, we performed an impairment test in 2010 of all long-lived assets not included in regulated rates. We determined that there was no impairment of long-lived assets because the undiscounted cash flows of the assets exceeded their carrying value.

We submitted a modified auction plan to the NYPSC on October 21, 2011, on behalf of RG&E and Cayuga, which the NYPSC adopted in its order issued and effective December 20, 2011. The modified plan provides for the bundling of the Allegany and Carthage generating stations as two components of one package, although separate bids will be accepted, and the other assets as a second package. Although we are to seek NYPSC guidance if the best bid for Allegany, which is owned by RG&E, would result in a loss, the same is not true for Carthage, which is owned by Cayuga. In filing the modified auction plan we reserved the right to petition the NYPSC for relief if the best bid for Carthage is below its net salvage value; however, the NYPSC did not address that statement in its order adopting the plan. RG&E will compare the auction results to the value that could be obtained through self-salvage before the disposition of the assets in the second package is determined.

As result of the recent order we performed another impairment test in 2011 assuming that the assets will ultimately be sold in compliance with the order. As a result, we have taken an impairment of $2.7 million on Carthage which is included in depreciation expense on the Statement of Operations. (See Note 12.)

We have determined that the criteria are not met in order to classify the assets as held for sale because the auction process is not expected to be completed within one year.

Note 18. CMP Rate Setting Process

CMP's rates are segregated into three primary components: transmission, distribution and stranded costs, each governed by a distinct regulatory process. The transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, as well as return of and on investment in transmission assets. The base return on equity is currently set at 11.14% with various additional return adders applicable to assets based upon vintage, voltage, and other factors. The formula also includes provisions to reflect forecasted plant additions in rates, subject to reconciliation in the following year. Pursuant to a FERC incentive rate order, CMP is also allowed to include the construction work in process related to the MPRP in rates, subject to the same reconciliation mechanism.

CMP's distribution service rates are established pursuant to ARP 2008 approved by the MPUC with a five-year term that commenced on January 1, 2009. Under ARP 2008, our distribution service prices are adjusted on July 1 each year based on an inflation index minus a 1% productivity factor. The rate plan also includes annual price change provisions for the recovery of significant unanticipated costs, including costs arising from changes in law, capital gains or losses, environmental remediation and extraordinary storms. CMP's operational performance is measured annually under the plan by seven service quality indicators and it is subject to penalties of up to $5 million for failure to achieve targeted levels of performance.

CMP recovers "stranded costs" pursuant to annual price adjustments that are also regulated by the MPUC. Those costs primarily include above-market costs of electric capacity and energy purchased under long-term power purchase agreements, as well as costs associated with CMP's interests in four decommissioned nuclear generation facilities. Stranded costs rates are periodically established based upon forecasts and are then fully reconciled to actual costs and recovery amounts on an annual basis.

Note 19. Sale of Nonutility Companies

On February 10, 2012, the IUSA Board of Directors agreed to sell the Hartford Steam Corporation and CNE Energy Power 1 LLC, two of our nonutility subsidiaries. As part of the transaction, IUSA will also sell two of the intermediate holding companies, TEN Companies and the Energy Network. Other subsidiaries of these intermediate holding companies will be retained by IUSA. The total consideration to be received is $50.5 million. We expect the transaction to close in the first half of 2012.

As of December 31, 2011, the four companies had aggregate total assets of $49 million and net assets of $29 million. For the twelve months ended December 31, 2011, aggregate revenue was $30 million and aggregate net income was $3.4 million. For the twelve months ended December 31, 2010, aggregate revenue was $32 million and aggregate net income was $2.9 million.

Notes to Consolidated Financial Statements

The following table provides the carrying amounts of the major classes of assets and liabilities of the companies as of December 31, 2011.

(Thousands)	
Assets	
Current assets	$9,725
Utility plant, net	27,241
Other property and investments	6,680
Goodwill	3,784
Other assets	1,925
Total assets	$49,355
Liabilities	
Accounts payable	$2,142
Notes payable	7,145
Other current liabilities	4,269
Deferred income taxes	3,747
Other liabilities	3,190
Total liabilities	$20,493

Management has determined that as of December 31, 2011, the criteria had not been met to classify these assets as held for sale.

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Management's Report on Internal Control Over Financial Reporting

Iberdrola USA, Inc.'s (the company) internal control over financial reporting is a process affected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. An entity'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 entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and those charged with governance; and (3) provide reasonable assurance regarding prevention, or timely detection and correction of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Management is responsible for establishing and maintaining effective internal control over financial reporting. Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2012, based on the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework*. Based on that assessment, management concluded that, as of December 31, 2012, the company's internal control over financial reporting is effective based on the criteria established in *Internal Control—Integrated Framework*. The effectiveness of the company's internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent public accounting firm, as stated in their report which appears herein.

Iberdrola USA, Inc.
February 7, 2013

Report of Independent Auditors

To the Stockholder and Board of Directors of Iberdrola USA, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income, of changes in equity and of cash flows present fairly, in all material respects, the financial position of Iberdrola USA, Inc. and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assertion of the effectiveness of internal control over financial reporting, included in *Management's Report on Internal Control Over Financial Reporting* listed in the accompanying Index to the Iberdrola USA, Inc. Consolidated Financial Statements for the Years Ended December 31, 2012 and 2011. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits of the financial statements in accordance with auditing standards generally accepted in the United States of America and our audit of internal control over financial reporting in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process effected by those charged with governance, management and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 those charged with governance; and (iii) provide reasonable assurance regarding prevention or timely detection and correction of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect and correct 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.

PricewaterhouseCoopers LLP

February 7, 2013

Iberdrola USA, Inc.
Consolidated Statements of Operations

Year ended December 31,	2012	2011
(Thousands)		
Operating Revenues		
Electricity	**$2,433,556**	$2,575,658
Natural gas and other	**652,933**	716,939
Total Operating Revenues	**3,086,489**	3,292,597
Operating Expenses		
Electricity purchased and fuel used in generation	**652,325**	882,706
Natural gas purchased	**245,823**	333,666
Other operating expenses	**834,147**	802,528
Maintenance	**235,561**	259,249
Depreciation and amortization	**235,267**	220,039
Other taxes	**277,777**	256,076
Total Operating Expenses	**2,480,900**	2,754,264
Operating Income	**605,589**	538,333
Other (Income)	**(48,241)**	(49,483)
Other Deductions	**11,379**	62,367
Interest Charges, Net	**245,572**	221,845
Income From Continuing Operations Before Income Tax	**396,879**	303,604
Income Tax Expense	**150,889**	39,295
Income From Continuing Operations	**245,990**	264,309
Discontinued Operations		
Income from discontinued operations (including gain on sale of $118,865 in 2012)	**131,230**	15,093
Income tax expense (benefits) (including taxes on sale of $49,363 in 2012)	**56,816**	(3,777)
Income From Discontinued Operations	**74,414**	18,870
Net Income	**320,404**	283,179
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	**670**	528
Net Income Attributable to Other Noncontrolling Interests	**1,283**	1,439
Net Income Attributable to Iberdrola USA	**$318,451**	$281,212

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

Iberdrola USA, Inc.
Consolidated Statements of Comprehensive Income

Year ended December 31,	2012	2011
(Thousands)		
Net Income	**$320,404**	$283,179
Other Comprehensive Income (Loss), Net of Tax		
Net unrealized holding gain (loss) on investments	**344**	(164)
Amortization of pension cost for nonqualified plans	**277**	1,126
Unrealized gain (loss) on derivatives qualified as hedges:		
Unrealized gain (loss) during period on derivatives qualified as hedges	**6,673**	(14,960)
Reclassification adjustment for loss (gain) included in net income	**595**	(411)
Net unrecognized gain on settled cash flow treasury hedges	**5,617**	5,554
Net unrealized gain (loss) on derivatives qualified as hedges	**12,885**	(9,817)
Other Comprehensive Income (Loss)	**13,506**	(8,855)
Comprehensive Income	**333,910**	274,324
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	**670**	528
Comprehensive Income Attributable to Other Noncontrolling Interests	**1,283**	1,439
Comprehensive Income Attributable to Iberdrola USA	**$331,957**	$272,357

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

Iberdrola USA, Inc.
Consolidated Balance Sheets

December 31,	2012	2011
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$26,010**	$65,862
Accounts receivable and unbilled revenues, net	**547,740**	612,619
Notes receivable from affiliate	**109,000**	-
Fuel and natural gas in storage, at average cost	**48,786**	78,741
Materials and supplies, at average cost	**48,278**	35,898
Deferred income taxes	**194,474**	74,189
Prepaid income taxes	**-**	9,813
Broker margin accounts	**8,504**	32,043
Prepayments and other current assets	**94,735**	100,852
Total Current Assets	**1,077,527**	1,010,017
Utility Plant, at Original Cost		
Electric	**7,442,444**	6,817,975
Natural gas	**1,553,076**	1,481,997
Common	**588,811**	567,218
	9,584,331	8,867,190
Less accumulated depreciation	**3,271,961**	3,167,250
Net Utility Plant in Service	**6,312,370**	5,699,940
Construction work in progress	**931,819**	849,095
Total Utility Plant	**7,244,189**	6,549,035
Other Property and Investments		
Other property and investments	**120,100**	139,043
Tax equity investments	**416,319**	420,856
Total Other Property and Investments	**536,419**	559,899
Regulatory and Other Assets		
Regulatory assets		
Nuclear plant obligations	**17,775**	50,256
Unfunded future income taxes	**453,405**	433,366
Environmental remediation costs	**142,559**	175,312
Unamortized loss on debt reacquisitions	**31,641**	37,473
Nonutility generator termination agreements	**11,762**	23,524
Natural gas hedges	**10,148**	36,435
Pension and other postretirement benefits	**1,103,667**	1,105,474
Storm costs	**224,096**	134,699
Other	**305,396**	230,142
Total regulatory assets	**2,300,449**	2,226,681
Other assets		
Goodwill	**981,646**	983,646
Other	**60,907**	71,864
Total other assets	**1,042,553**	1,055,510
Total Regulatory and Other Assets	**3,343,002**	3,282,191
Total Assets	**$12,201,137**	$11,401,142

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

Iberdrola USA, Inc.
Consolidated Balance Sheets

December 31,	2012	2011
(Thousands, except shares)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	**$151,888**	$155,637
Current portion of long-term debt with affiliates	**200,000**	-
Notes payable	**178,974**	74,800
Accounts payable and accrued liabilities	**407,522**	479,245
Accounts payable, electricity purchased	**56,498**	62,936
Accounts payable, natural gas purchased	**18,880**	25,356
Interest accrued	**54,515**	30,550
Interest accrued on debt to affiliates	**6,934**	7,568
Taxes accrued	**80,909**	46,037
Derivative liabilities	**10,750**	40,237
Environmental remediation costs	**40,723**	50,258
Other	**210,832**	221,855
Total Current Liabilities	**1,418,425**	1,194,479
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligations	**702,024**	712,378
Deferred income taxes	**512,619**	486,507
Gain on sale of generation assets	**42,642**	44,945
Pension benefits	**16,324**	14,750
Positive benefit adjustments	**77,431**	124,416
Other	**268,043**	194,799
Total regulatory liabilities	**1,619,083**	1,577,795
Other liabilities		
Deferred income taxes	**1,506,837**	1,200,935
Nuclear plant obligations	**127,125**	135,473
Pension and other postretirement benefits	**657,792**	629,266
Environmental remediation costs	**144,849**	146,775
Derivative liabilities	**167**	8,346
Other	**162,950**	186,225
Total other liabilities	**2,599,720**	2,307,020
Total Regulatory and Other Liabilities	**4,218,803**	3,884,815
Long-term Debt		
Other long-term debt	**2,456,108**	2,232,998
Long-term debt with affiliates	**350,000**	650,000
Total Long-term Debt	**2,806,108**	2,882,998
Total Liabilities	**8,443,336**	7,962,292
Commitments and Contingencies		
Preferred Stock of Subsidiaries		
Redeemable preferred stock, noncontrolling interests	**192**	12,464
Iberdrola USA Common Stock Equity		
Common stock ($.01 par value, 100 shares authorized and outstanding at December 31, 2012 and 2011)	**-**	-
Capital in excess of par value	**2,009,101**	2,009,101
Retained earnings	**1,814,680**	1,496,229
Accumulated other comprehensive loss	**(80,553)**	(94,059)
Total Iberdrola USA Common Stock Equity	**3,743,228**	3,411,271
Other Noncontrolling Interests	**14,381**	15,115
Total Equity	**3,757,609**	3,426,386
Total Liabilities and Equity	**$12,201,137**	$11,401,142

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

Iberdrola USA, Inc.
Consolidated Statements of Cash Flows

Year Ended December 31,	2012	2011
(Thousands)		
Cash Flow from Operating Activities		
Net income	**$320,404**	$283,179
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**235,986**	228,395
Amortization of regulatory and other assets and liabilities	**21,932**	44,751
Gain on sale of Seneca Lake Storage facility	**-**	(12,397)
Gain on sale of nonutility subsidiaries	**(118,865)**	-
Deferred income taxes and investment tax credits, net	**154,396**	78,056
Pension expense	**80,694**	38,718
Amortization of positive benefit adjustments	**(46,985)**	(75,923)
Transmission revenue	**41,477**	8,196
Changes in current operating assets and liabilities		
Accounts receivable and unbilled revenues, net	**64,805**	29,160
Broker margin accounts	**23,539**	(9,967)
Inventory	**17,575**	(2,641)
Prepaid income taxes	**64,062**	69,694
Prepayments and other current assets	**5,095**	(865)
Accounts payable and accrued liabilities	**(13,271)**	(57,164)
Interest accrued	**23,331**	4,612
Taxes accrued	**3,769**	(11,466)
Pension and other postretirement benefits contributions	**(27,180)**	(32,577)
VEBA withdrawal	**8,380**	33,813
Changes in other assets		
Deferred storm costs	**(90,522)**	(84,926)
Advanced metering infrastructure	**(7,484)**	(17,960)
Changes in other liabilities		
Environmental remediation costs	**6,865**	39,542
Constellation revenue	**10,000**	-
Other	**(47,194)**	45,231
Net Cash Provided by Operating Activities	**730,809**	597,461
Cash Flow from Investing Activities		
Utility plant additions	**(1,035,264)**	(822,409)
Grants received from governmental entities	**13,445**	47,755
Proceeds from sale of nonutility subsidiaries	**151,800**	-
Proceeds from sale of Seneca Lake Storage facility	**-**	65,000
Other property sold	**-**	4,814
Notes receivable from affiliate	**(109,000)**	-
Proceeds from sale of investment	**3,431**	5,518
Net Cash (Used in) Investing Activities	**(975,588)**	(699,322)
Cash Flow from Financing Activities		
Repurchase of preferred stock of subsidiaries, including net premiums	**(12,272)**	-
Long-term debt repayments, debt with affiliates	**(100,000)**	-
Long-term note issuances	**375,000**	275,000
Costs associated with debt issuance	**(3,653)**	-
Long-term note repayments	**(155,635)**	(114,777)
Notes payable three months or less, net	**104,174**	(67,600)
Dividends to other noncontrolling interests	**(2,017)**	(60)
Dividends paid on preferred stock of subsidiaries, noncontrolling interests	**(670)**	(528)
Net Cash Provided by Financing Activities	**204,927**	92,035
Net Decrease in Cash and Cash Equivalents	**(39,852)**	(9,826)
Cash and Cash Equivalents, Beginning of Year	**65,862**	75,688
Cash and Cash Equivalents, End of Year	**$26,010**	$65,862

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

Iberdrola USA, Inc.
Consolidated Statements of Changes in Equity

	Iberdrola USA Shareholder							
(Thousands, except per share amounts)	Common Stock Outstanding $.01 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Other Noncontrolling Interests	Comprehensive Income (Loss)*	Total
Balance, January 1, 2011	-	-	$2,009,101	$1,215,017	$(85,204)	$13,736		$3,152,650
Net income*				281,212		1,439	$282,651	282,651
Other comprehensive (loss), net of tax					(8,855)		(8,855)	(8,855)
Comprehensive income*							$273,796	273,796
Dividends to other noncontrolling interests						(60)		(60)
Balance, December 31, 2011	-	-	2,009,101	1,496,229	(94,059)	15,115		3,426,386
Net income*				318,451		1,283	$319,734	319,734
Other comprehensive income, net of tax					13,506		13,506	13,506
Comprehensive income*							$333,240	333,240
Dividends to other noncontrolling interests						(2,017)		(2,017)
Balance, December 31, 2012	-	-	$2,009,101	$1,814,680	$(80,553)	$14,381		$3,757,609

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

*Amounts do not include Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests of $528 for 2011 and $670 for 2012.

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background: Iberdrola USA, Inc. (Iberdrola USA, the company, we, our, us) is a public utility holding company operating under the Public Utility Holding Company Act of 2005. Iberdrola USA is a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain. We are a super-regional energy services and delivery company with operations in New York, Maine, Connecticut and New Hampshire. Our wholly-owned subsidiaries, and their principal operating companies, include: CMP Group, Inc. – Central Maine Power Company (CMP), and RGS Energy Group, Inc. – New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E). During 2012 we sold some of our primary nonutility subsidiaries (See Note 2).

We have evaluated events or transactions that occurred after December 31, 2012, for inclusion in these financial statements through February 7, 2013, which is the date these financial statements were available to be issued.

Accounts receivable**:** Accounts receivable at December 31 include unbilled revenues of $126 million for 2012 and $131 million for 2011, and are shown net of an allowance for doubtful accounts at December 31 of $57 million for 2012 and $49 million for 2011. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $43 million in 2012 and $37 million in 2011.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and delivery loss factors. Changes in those assumptions could significantly affect the estimates of unbilled revenues.

The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience for each service region and operating segment. Each month the operating companies review their allowance for doubtful accounts and past due accounts over 90 days and/or above a specified amount, and review all other balances on a pooled basis by age and type of receivable. When an operating company believes that a receivable will not be recovered, it charges off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer of CMP, NYSEG or RG&E becomes delinquent in making payments, the companies' state regulatory commissions require them to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended time by negotiating mutually acceptable payment terms. Generally, the utility company must continue to serve a customer who cannot pay an account balance in full if the customer: pays a reasonable portion of the balance; agrees to pay the balance in installments; and agrees to pay future bills within 30 days until the DPA is paid in full. DPA receivable balances, net of the applicable reserve, at December 31 were: $51 million for 2012 and $66 million in 2011.

Asset retirement obligations**:** We record the fair value of the liability for an asset retirement obligation (ARO) and/or a conditional ARO in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability to its present value periodically over time, and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. Our regulated utilities defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

Our ARO at December 31, including our conditional ARO, was $35 million for 2012 and $34 million for 2011. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of: asbestos, PCB-contaminated equipment, gas pipeline and cast iron gas mains.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2012 and 2011.

Year ended December 31,	**2012**	**2011**
(Thousands)		
ARO, beginning of year	**$34,200**	$33,678
Liabilities settled during the year	**(1,321)**	(1,273)
Liability incurred during the year	**431**	-
Accretion expense	**2,194**	2,169
Revisions in estimated cash flows	**(45)**	(374)
ARO, end of year	**$35,459**	$34,200

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

Accrued removal obligations: Our regulated utilities meet the requirements concerning accounting for regulated operations, and recognize a regulatory liability, for financial reporting purposes only, for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Consolidated statements of cash flows**:** We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and those investments are included in cash and cash equivalents.

Supplemental Disclosure of Cash Flows Information	**2012**	**2011**
(Thousands)		
Cash paid (received) during the year ended December 31:		
Interest, net of amounts capitalized	**$184,918**	$169,127
Income taxes paid (received), net	**$3,169**	$(26,306)

Interest capitalized was $9.7 million in 2012 and $7.5 million in 2011. We have increased utility plant additions by $71 million for amounts payable as of December 31, 2012, and decreased them by $151 million as of December 31, 2011.

Notes to Consolidated Financial Statements

***Preliminary survey costs*:** Consolidated preliminary survey costs included in Other assets at December 31 totaled approximately $15 million for 2012 and $13 million for 2011. Preliminary survey costs represent expenditures incurred for the purpose of determining the feasibility of utility projects under contemplation. When construction begins on such projects, the amounts are moved to Construction work in progress (CWIP), and then eventually to Utility plant when construction is completed and the asset is placed in service. If a project is abandoned, the costs incurred for that project are charged to an appropriate expense account.

***Depreciation*:** We determine depreciation expense substantially using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal, in service at each operating company. The weighted-average service lives of certain classifications of property are: transmission property - 54 years, distribution property - 54 years, generation property - 60 years and other property - 36 years. Our depreciation accruals were equivalent to 2.6% of average depreciable property for 2012 and 2011.

We charge repairs and minor replacements to operating expense, and capitalize renewals and betterments, including certain indirect costs. We charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation.

***Goodwill*:** We are required to perform an annual goodwill impairment assessment at the same time each year and, accordingly, we perform our annual impairment assessment of goodwill during the third quarter of each year. We update it between annual assessments if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value.

Effective for annual and interim goodwill impairment assessments for fiscal years beginning after December 15, 2011, an entity is allowed to first assess qualitative factors – also referred to as step zero – to determine if there are events or circumstances that indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount, including goodwill. If it is not more likely than not that the fair value is less than the carrying amount, then it is not necessary to perform the two-step quantitative goodwill impairment test. An entity has the option to bypass step zero for any reporting unit in any period and proceed directly to performing step one of the goodwill impairment test, and may resume performing the step zero qualitative assessment in any subsequent period.

If step zero indicates that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the entity would perform step one of the two-step impairment test. Step one of the impairment test involves comparing the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of goodwill impairment loss. If the carrying amount is less than fair value, further testing for goodwill impairment is not performed.

Step two of the goodwill impairment test involves comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. In step two, determining the implied fair value of goodwill requires the valuation of a reporting unit's identifiable tangible and intangible assets and liabilities as if the reporting unit had been acquired in a business combination on the testing date. The difference between the fair value of the entire reporting unit as determined in step one and the net fair value of all identifiable assets and liabilities represents the implied fair value of goodwill. A goodwill impairment charge, if any, would be the difference between the carrying amount of goodwill and the implied fair value of goodwill upon the completion of step two.

Notes to Consolidated Financial Statements

We may be required to recognize an impairment of goodwill in the future due to market conditions or other factors related to our performance. Those market events could include a decline in the forecasted results in our business plan, significant adverse rate case results, changes in capital investment budgets or changes in interest rates that could permanently impair the fair value of a reporting unit. Recognition of impairments of a significant portion of goodwill would negatively affect our reported results of operations and total capitalization, the effect of which could be material and could make it more difficult to maintain our credit ratings, secure financing on attractive terms, maintain compliance with debt covenants and meet expectations of our regulators.

Government grants: Authoritative accounting principles generally accepted in the United States of America do not address accounting for government grants. For that reason, we account for government grants related to depreciable assets in accordance with the prescribed Federal Energy Regulatory Commission (FERC) accounting for contributions in aid of construction, that is, the grant amount is credited to the cost of the related property, plant and equipment. In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as compensation for expenses already incurred in profit or loss in the period in which the expenses are incurred.

New accounting standards adopted: We have adopted new accounting standards issued by the Financial Accounting Standards Board (FASB) as explained below.

Testing Goodwill for Impairment: In September 2011 the FASB issued amendments to the standards for testing goodwill for impairment that allow an entity to first assess qualitative factors to determine whether it needs to perform the two-step quantitative goodwill impairment test. An entity will not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not (a likelihood of more than 50 percent) that the fair value of the reporting unit is less than its carrying amount. The update includes a number of factors to consider in conducting the qualitative assessment. The amendments are effective for all entities for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011, with early adoption permitted. Our adoption of the amendments did not affect our results of operation, financial position or cash flows.

Comprehensive Income: In June 2011 the FASB issued amendments to improve the presentation of comprehensive income and improve convergence of U.S. generally accepted accounting principles (GAAP) and International Financial Reporting Standards (IFRS). The amendments give more importance to items reported in other comprehensive income (OCI) by eliminating the option to present components of OCI as part of the statement of changes in stockholders' equity. They require all nonowner changes in stockholders' equity to be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Both options require an entity to present each component of net income along with total net income, each component of OCI along with a total for OCI, and a total amount for comprehensive income. The amendments are to be applied retrospectively and are effective for nonpublic entities for fiscal years ending after December 15, 2012, and interim and annual periods thereafter. We present all nonowner changes in stockholder's equity in two separate but consecutive statements and comply with the presentation requirements. Our adoption of the amendments did not affect our results of operation, financial position or cash flows.

In December 2011 the FASB issued an update to the above amendment, to defer the effective date for amendments to the presentation of reclassification items out of accumulated other comprehensive income (AOCI). The update addresses concerns that presentation requirements about reclassifications of items out of AOCI would be costly for preparers and may add unnecessary complexity to financial statements. The update defers the effective date only for the changes that relate to the presentation of the reclassification adjustments, and will allow the FASB time to redeliberate whether to require presentation on the face of the financial statements of the effects of reclassifications out of AOCI on the components of net income and OCI for all periods presented.

Fair Value Measurement: The FASB issued an update in May 2011 for amendments that are the result of the FASB's and the International Accounting Standards Board (IASB)'s work to ensure that fair value has the same meaning and to develop common requirements for measuring fair value and disclosing information about fair value measurements in accordance with U.S. GAAP and IFRS. The amendments explain how to measure fair value but do not require additional fair value measurements and are not intended to establish valuation standards or affect valuation practices outside of financial reporting. The primary changes relate to: highest and best use and the valuation premise, measuring portfolios of financial instruments, blockage factors and other premiums and discounts, and disclosures (with certain exceptions for disclosure requirements for nonpublic entities). Other new or clarifying guidance relates to: the principal (or most advantageous) market, application to liabilities, and instruments classified within shareholders' equity. Remaining key differences relate to: day one gains and losses, measuring the fair value of certain investments (net asset value or its equivalent) and certain quantitative sensitivity analysis disclosures. The amendments are to be applied prospectively and are effective for nonpublic entities for annual periods beginning after December 15, 2011, with early application permitted, but no earlier than interim periods beginning after December 15, 2011. Our adoption of the amendments did not affect our results of operation, financial position or cash flows.

Troubled Debt Restructurings: In April 2011 the FASB issued an update that amends its accounting standards concerning determining whether a debt restructuring is a troubled debt restructuring (TDR). A restructuring is a TDR if a creditor for economic or legal reasons related to a debtor's financial difficulties grants a concession to the debtor that the creditor would otherwise not consider. The amendments provide additional guidance to creditors for evaluating whether the creditor has granted a concession and whether the debtor is experiencing financial difficulties. The amendments apply to all creditors, both public and nonpublic, that restructure receivables that are within the scope of the accounting and reporting requirements concerning TDRs. The update also ends the deferral of additional disclosures about TDR activities that had been required by an update issued in July 2010 concerning disclosures about the credit quality of financing receivables and the allowance for credit losses. The amendments are effective for nonpublic entities for annual periods ending on or after December 15, 2012, including interim periods within those annual periods. Our adoption of the amendments did not affect our results of operation, financial position or cash flows.

New accounting standards issued but not yet adopted: New accounting standards issued by the FASB that we have not yet adopted in these financial statements are as explained below.

Disclosures about Offsetting Assets and Liabilities: In December 2011 the FASB amended the requirements concerning disclosures about offsetting assets and liabilities. The amendments do not change the FASB's current offsetting model but will require enhanced disclosures and provide for converged FASB and IASB disclosures about financial instruments and derivative instruments that are either offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement. The disclosures are meant to enable users of an entity's financial statements to understand the effect of offsetting and related arrangements on the entity's financial position. Entities are required to provide both net and gross information about assets and liabilities so as to enhance comparability between entities that prepare their financial statements either based on U.S. GAAP or based on IFRS. The amendments are effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods.

Notes to Consolidated Financial Statements

The disclosures required by the amendments are to be provided retrospectively for all comparative periods presented. Our adoption of the amendments will not affect our results of operation, financial position or cash flows.

Technical Corrections and Improvements: In October 2012 the FASB issued amendments to make certain technical corrections to a wide variety of Topics in its Accounting Standards Codification. The amendments are generally not substantive, and include amendments that identify when the use of *fair value* should be linked to the definition of fair value in Topic 820, *Fair Value Measurement*, as well as conforming amendments to reflect the measurement and disclosure requirements of Topic 820. The amendments are not expected to significantly affect current accounting practice, and are not expected to create any new differences between U.S. GAAP and IFRS. The amendments not subject to the transition guidance were effective upon issuance for both public entities and nonpublic entities. For nonpublic entities, the amendments that are subject to the transition guidance are effective for fiscal periods beginning after December 15, 2013. Our adoption of the amendments will not affect our results of operation, financial position or cash flows.

***Other (Income) and Other Deductions*:**

Year Ended December 31,	**2012**	**2011**
(Thousands)		
Interest and dividend income	**$(6,460)**	$(1,096)
Allowance for funds used during construction	**(13,058)**	(11,096)
Earnings from equity investments	**(4,380)**	(4,480)
Gain on sale of Seneca Lake Storage facility (See Note 16)	**-**	(12,397)
Carrying costs on regulatory assets	**(21,786)**	(19,964)
Miscellaneous	**(2,557)**	(450)
Total other (income)	**$(48,241)**	$(49,483)
Civic donations	**$2,155**	$1,395
Losses from tax equity investments (See Note 8)	**4,545**	57,157
Miscellaneous	**4,679**	3,815
Total other deductions	**$11,379**	$62,367

***Principles of consolidation*:** These financial statements consolidate our majority-owned subsidiaries after eliminating intercompany transactions.

***Reclassifications*:** Certain amounts have been reclassified in our consolidated statements of cash flows to conform to the 2012 presentation.

***Regulatory assets and liabilities*:** Our public utility subsidiaries currently meet the requirements concerning accounting for regulated operations for their electric and natural gas operations in New York and Maine; however, we cannot predict what effect the competitive market or future actions of regulatory entities would have on their ability to continue to do so. If our public utility subsidiaries were to no longer meet the requirements concerning accounting for regulated operations for all or a separable part of their operations, they may have to record certain regulatory assets and regulatory liabilities as an expense or as revenue, or include them in accumulated other comprehensive income.

Pursuant to the requirements concerning accounting for regulated operations our utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. Substantially all regulatory assets for which funds have been expended are either included in rate base or are accruing carrying costs. As a result of the rate plans approved in 2010 for NYSEG and RG&E (see note 15), the majority of regulatory assets and liabilities were reflected in rates. The primary regulatory assets and liabilities that have been accrued since then and are accruing carrying costs until included in rates are the deferred storm costs discussed below, and various deferrals, both assets and liabilities, resulting from reconciliation mechanisms designed to allow recovery of actual costs. Our operating utilities also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs.

Our three operating utilities are allowed to defer the costs of service restoration resulting from major storms when they meet certain criteria for severity and duration. During 2012 and 2011 we experienced an unusually high level of restoration costs resulting from storms including Hurricane Sandy, Hurricane Irene, tropical storm Lee and an early winter snowstorm in late October 2011. We incurred a total of $110 million in 2012 and $99 million in 2011 related to the storms. The amount deferred, which reflects the excess over amounts currently allowed in rates is $93 million for 2012 and $85 million for 2011. The method of recovery of the costs will be determined in the future rate cases for each company.

Unfunded future income taxes and deferred income taxes are amortized as the related temporary differences reverse. Unamortized loss on debt reacquisitions is amortized over the lives of the related debt issues. Nuclear plant obligations, demand side management program costs, gain on sale of generation assets, other regulatory assets and other regulatory liabilities are amortized over various periods in accordance with each operating utility's current rate plans. Amortization of total regulatory assets net of amortization of total regulatory liabilities was $26 million in 2012 and $34 million in 2011.

Other regulatory assets and other regulatory liabilities consisted of:

December 31, **(Thousands)**	**2012**	**2011**
Other postretirement benefits	**$7,813**	$9,528
Loss on sale of RG&E Oswego generating unit	**5,445**	10,890
Asset retirement obligation	**33,089**	28,750
Deferred pension costs	**26,863**	43,458
Deferred property tax	**47,525**	45,307
Deferred meter replacement costs	**37,617**	23,876
Deferred natural gas costs	**3,916**	5,267
Nonbypassable wires charge	**2,362**	3,400
Funded deferred income tax true-up	**29,228**	-
Noncash return on deferred tax items	**53,056**	8,472
Cost to achieve efficiency initiatives	**10,511**	20,231
Other	**47,971**	30,963
Total other regulatory assets	**$305,396**	$230,142
Deferred natural gas costs	**$8,347**	$12,968
Asset retirement obligation	**4,417**	4,417
Economic development	**27,384**	39,096
Pension and other postretirement benefits	**10,605**	11,082
Plant decommissioning	**21,475**	12,510
Deferred property tax	**31,282**	15,923
Environmental	**7,557**	6,735
Merger capital expense target customer credit	**16,800**	16,800
Earning sharing mechanism	**8,855**	8,241
Noncash return on deferred tax items	**40,854**	13,968
Revenue decoupling mechanism	**11,621**	15,987
Other	**78,846**	37,072
Total other regulatory liabilities	**$268,043**	$194,799

Related party transactions: As part of the Iberdrola S.A. group, Iberdrola USA is a party to a number of intercompany revolving credit facilities under which it acts as either the lender or the borrower. The agreements allow Iberdrola USA as a borrower to supplement its own liquidity resources by accessing the liquidity resources of Iberdrola S.A. and, as a lender, to provide liquidity to other affiliates of Iberdrola S.A. in the U.S.

In August 2011 Iberdrola USA entered into an intercompany credit agreement under which it may borrow up to $600 million from Iberdrola Financiacion, S.A.U. Iberdrola USA pays a facility fee of 25 basis points. The agreement expires in August 2016. The facility has not been drawn upon since inception.

In December 2011 Iberdrola entered into a depository agreement with Scottish Power under which we earn a rate of 3-month Libor less 2 basis points on deposits. The agreement expires in December 2016. There were no balances under the agreement at December 31, 2012 and 2011.

In January 2012 Iberdrola USA entered into two intercompany revolving credit facilities, with expiration dates of December 31, 2012, intended to provide temporary liquidity to Iberdrola Renewables Holdings, Inc. (IRHI), an affiliate company and indirect subsidiary of Iberdrola S.A. Iberdrola USA is the borrower and Scottish Power Limited (Scottish Power) is the lender in an agreement with a $400 million limit. That agreement expired as scheduled on December 31, 2012. Iberdrola USA is the lender and IRHI is the borrower in an agreement with a $600 million limit. In December 2012 the expiration date of that agreement was extended to December 31, 2013, and the limit was reduced from $600 million to $300 million. There was $109 million outstanding at December 31, 2012, and $249 million at January 31, 2013. All other terms and conditions remained the same including the facility fee of 15 basis points and borrowing spread of 98 basis points over Libor.

In November 2010 Iberdrola USA entered into an agreement where it is the lender in a $100 million revolving credit facility and IRHI is the borrower. Under the agreement, the borrowing margin is 100 basis points over Libor. The agreement expires in 2015 and has no facility fees. There were no amounts outstanding under the agreement at December 31, 2012 and 2011.

See Note 5 concerning two long-term debt agreements with Scottish Power. Interest expense on the debt with Scottish Power for the year ended December 31 was $41 million for 2012 and $44 million for 2011.

See Note 8 concerning our related party transactions with respect to tax equity investments.

***Revenue recognition*:** We recognize revenues upon delivery of energy and energy-related products and services to our customers.

Pursuant to a Maine state law, CMP earns revenue for the delivery of energy to its retail customers, but is prohibited from selling power to them. CMP generally does not enter into purchase or sales arrangements for power with ISO New England Inc. (ISO-NE), the New England Power Pool, or any other independent system operator or similar entity. CMP generally sells all of its power entitlements under its nonutility generator (NUG) and other purchase power contracts to unrelated third parties under bilateral contracts. If the Maine Public Utilities Commission (MPUC) does not approve the terms of bilateral contracts, it can direct CMP to sell power entitlements that it receives from those contracts on the spot market through ISO-NE.

NYSEG and RG&E enter into power purchase and sales transactions with the New York Independent System Operator (NYISO). When NYSEG and RG&E sell electricity from owned generation to the NYISO, and subsequently repurchase electricity from the NYISO to serve their customers, they record the transactions on a net basis in their statements of income. NYSEG and RG&E net their purchase and sale transactions with the NYISO on an hourly basis.

NYSEG's and RG&E's electric and natural gas rate plans each contain a revenue decoupling mechanism under which their actual energy delivery revenues are compared on a periodic basis with the authorized delivery revenues and the difference accrued, with interest, for refund to or recovery from customers, as applicable. (See Note 15.)

In addition, our regulated utilities accrue revenue pursuant to the various regulatory provisions to record regulatory assets for revenues that will be collected in the future.

***Taxes*:** We file a consolidated federal income tax return and unitary and/or combined state income tax returns in certain jurisdictions and allocate income taxes among Iberdrola USA and its subsidiaries in proportion to their contribution to consolidated taxable income. The determination and allocation of our income tax provision and its components are outlined and agreed to in the tax sharing agreements among Iberdrola USA and its subsidiaries.

Deferred income taxes are recorded for the temporary differences between the financial statement and tax bases of assets and liabilities using currently enacted tax rates. Valuation allowances are established against deferred tax assets whenever circumstances indicate that it is more likely than not that such assets will not be realized in future periods. We amortize investment tax credits over the estimated lives of the related assets.

The State of New York imposes on corporations a franchise tax that is computed as the higher of a tax based on income or a tax based on capital. To the extent the Company's state tax based on capital is in excess of the state tax based on income, the Company reports such excess in other taxes and taxes accrued in the accompanying consolidated financial statements.

We account for sales tax collected from customers and remitted to taxing authorities on a net basis.

We classify all interest related to uncertain tax positions as interest expense. For the periods prior to 2012, the Company classified all interest related to uncertain tax positions as income tax expense. The gross interest accrued is $12.2 million as of December 31, 2012 and $2.2 million as of December 31, 2011.

Use of estimates and assumptions: The preparation of our consolidated financial statements in conformity with generally accepted accounting principles requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for doubtful accounts and unbilled revenues; (2) asset impairments, including goodwill; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; and (8) earnings sharing mechanism (ESM), nonbypassable wires charges and environmental remediation liability. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside experts to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Note 2. Discontinued Operations

On April 25, 2012, we sold The Hartford Steam Corporation (HSC) and CNE Power 1 LLC at an after-tax gain of $5.8 million. As part of the transaction, we also sold two of the intermediate holding companies, TEN Companies, Inc. (TEN) and The Energy Network, Inc., but retained other subsidiaries of the intermediate holding companies. The total consideration received was $50.6 million. Goodwill allocated to HSC, a subsidiary of TEN, was $2.0 million.

On August 22, 2012, we sold Energetix, Inc. and NYSEG Solutions, Inc. at an after-tax gain of $63.7 million. The contract price was $101.2 million. The actual cash received included various adjustments, including an adjustment for actual working capital levels at the time of the sale.

In November 2010 we sold three of our natural gas holding company subsidiaries and their natural gas distribution utilities to UIL. The transaction was valued at $1,296 million, including the assumption of approximately $386 million of debt. The agreement provided for an adjustment to the final purchase price for actual cash and working capital balances as of the date of the sale. In May 2011 IUSA made a payment to UIL of $11 million for the working capital adjustment. Income taxes on the sale were also adjusted by $15 million in 2011 to reflect the actual income tax expense resulting from filing our 2010 tax return in September 2011, including the effect of the working capital payment.

In addition to the items discussed above, discontinued operations includes the operating results of Carthage Energy, owned by Cayuga Energy, Inc., which has $1.1 million of assets held for sale at December 31, 2012. (See Note 17.) Amounts are immaterial and therefore not disclosed separately on the balance sheet.

Notes to Consolidated Financial Statements

The results of discontinued operations of the businesses sold were:

Year Ended December 31,	2012	2011
(Thousands)		
Hartford Steam Company/CNE Power 1, LLC and two intermediate holding companies		
Revenues	**$10,058**	$27,734
Income from operations of discontinued businesses (including gain on disposal of $11,223 in 2012)	**11,200**	4,631
Income tax expense (including taxes on sale of $5,409 in 2012)	**6,083**	1,189
Income from discontinued operations	**5,117**	3,442
Energetix, Inc. and NYSEG Solutions, Inc.		
Revenues	**185,398**	326,128
Income from operations of discontinued businesses (including gain on disposal of $107,642 in 2012)	**124,669**	25,507
Income tax expense (including taxes on sale of $43,954 in 2012)	**50,733**	9,957
Income from discontinued operations	**73,936**	15,550
Carthage Energy, LLC		
Revenues	**1,574**	1,077
(Loss) from operations of discontinued business	**(4,639)**	(3,962)
(Loss) from discontinued operations	**(4,639)**	(3,962)
Natural Gas Companies		
(Loss) from operations of discontinued businesses	**-**	(11,083)
Income tax (benefits)	**-**	(14,923)
Income from discontinued operations	**-**	3,840
Totals for discontinued operations		
Total revenues	**197,030**	354,939
Total gain from operations of discontinued businesses	**131,230**	15,093
Total income tax expense (benefits)	**56,816**	(3,777)
Total income from discontinued operations	**$74,414**	$18,870

The following table provides the carrying amounts of the major classes of assets and liabilities of the companies sold as of December 31, 2011.

(Thousands)	
Assets	
Current assets	$41,863
Utility plant, net	27,241
Other property and investments	12,164
Goodwill	3,784
Other assets	6,856
Total assets	**$91,908**
Liabilities	
Accounts payable	$14,302
Notes payable	4,949
Other current liabilities	35,025
Deferred income taxes	3,959
Other postretirement benefits	1,615
Other liabilities	2,129
Total liabilities	**$61,979**

Notes to Consolidated Financial Statements

Note 3. Goodwill

We do not amortize goodwill, but perform a goodwill impairment assessment at least annually as described in Note 1. Our step zero qualitative assessment involves evaluating key events and circumstances, using income and market approaches, that could affect the fair value of our reporting units, as well as other factors. Events and circumstances evaluated include: macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting a reporting unit. Our step one impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of our marginal, weighted-average cost of capital, and forecasted cash flows. We test the reasonableness of the conclusions of our step one impairment testing using a range of discount rates and a range of assumptions for long-term cash flows.

We had no impairment of goodwill in 2012 or in 2011 as a result of our annual impairment assessment, which we perform in the third quarter each year. For 2012, as a result of our step zero qualitative assessment, it was not more likely than not that the fair value of each reporting unit was less than its carrying amount, and it was not necessary to perform the two-step goodwill impairment test. For 2011, as a result of our step one testing, no impairment was indicated within any of the ranges of assumptions analyzed for our New York, Maine or nonutility reporting units. There were no events or circumstances subsequent to our annual impairment assessment for 2012 or for 2011 that required us to update the assessment.

We sold nonutility subsidiaries during 2012 (see Note 2), which helped us continue to meet strategic objectives of our parent, Iberdrola S.A. One of the subsidiaries that we sold during the year was Hartford Steam Company a subsidiary of the Ten Companies. Hartford Steam had $2.0 million in allocated goodwill. There was no goodwill associated with any of the other nonutility subsidiaries sold.

The carrying amount of goodwill as of December 31, 2012 and 2011, is shown in the following table. Goodwill has not been adjusted to reflect Iberdrola's purchase of Energy East

	2012	**2011**
(Thousands)		
Balance as of January 1		
Goodwill	**$983,888**	$983,888
Accumulated impairment losses	**(242)**	(242)
	983,646	983,646
Goodwill related to sale of business units	**(2,000)**	-
Balance as of December 31		
Goodwill	**981,888**	983,888
Accumulated impairment losses	**(242)**	(242)
	$981,646	$983,646

Notes to Consolidated Financial Statements

Note 4. Income Taxes

Year Ended December 31,	2012	2011
(Thousands)		
Current		
Federal	**$27,240**	$(54,275)
State	**18,708**	13,738
Current taxes charged to expense	**45,948**	(40,537)
Deferred		
Federal	**46,159**	80,375
State	**60,910**	1,581
Deferred taxes charged to expense	**107,069**	81,956
Investment tax credit adjustments	**(2,128)**	(2,124)
Total for Continuing Operations	**$150,889**	$39,295

The $27.2 million current federal tax expense primarily represents the effect on current tax expense of a reclassification of current and deferred tax expense associated with net operating losses (NOL) as a result of the filing of our 2011 tax return. The $54.3 million federal tax benefit in 2011 represents the recording of tax benefits associated with the filing of our 2010 income tax return in 2011 as compared to the estimated taxes recorded in 2010.

The increase in the deferred tax expense in 2012 as compared to 2011 is primarily due to the utilization of federal and state net operating loss deferred tax assets in 2012. In 2011 we were in a tax loss situation and as a result recorded significant net operating loss deferred tax assets, offsetting a substantial portion of the deferred tax expense recorded as a result of 100% federal bonus depreciation.

Our tax expense differed from the expense at the federal statutory rate of 35% due to the following:

Year Ended December 31,	2012	2011
(Thousands)		
Tax expense at federal statutory rate	**$138,908**	$105,141
Depreciation and amortization not normalized	**2,835**	3,370
Investment tax credit amortization	**(2,128)**	(2,124)
Removal costs	**(9,375)**	(8,735)
Medicare subsidy	**3,701**	2,742
Tax return and audit adjustments	**291**	(2,825)
Tax equity investment depreciation not normalized	**-**	(38,092)
Tax equity investment production tax credits	**(25,023)**	(25,341)
State taxes, net of federal benefit	**51,753**	9,958
Other, net	**(10,073)**	(4,799)
Total for Continuing Operations	**$150,889**	$39,295

Income taxes were $12.0 million more in 2012 than they would have been at the federal statutory rate of 35% and $65.8 million less in 2011. The 2012 effective tax rate was higher than the statutory rate primarily due to the recording of various state tax reserves, offset by the tax benefits associated with the generation of production tax credits associated with our tax equity investments in two wind farm partnerships (see Note 8), and recurring flow-through tax effects, including those associated with removal costs. The 2011 effective tax rate was less than the statutory rate primarily due to the tax benefits, including production tax credits, associated with our tax equity investments in two wind farm partnerships, and recurring flow-through tax impacts, including removal costs.

Notes to Consolidated Financial Statements

Our consolidated deferred tax assets and liabilities consisted of:

December 31, (Thousands)	2012	2011
Production tax credit carryforward	**$89,151**	-
Federal and state net operating loss carryforwards	**38,133**	-
Other	**67,190**	$74,189
Current Deferred Income Tax Assets	**$194,474**	$74,189
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property related	**$1,739,626**	$1,615,137
Pension	**217,332**	241,489
Unfunded future income taxes	**184,887**	176,449
Deferred gain on sale of generation assets	**5,750**	17,567
Accumulated deferred investment tax credits	**19,500**	21,629
Federal and state net operating loss carryforwards	**(31,040)**	(159,012)
Production Tax Credit carryforward	**-**	(64,129)
Other postretirement benefits	**(102,561)**	(100,116)
Positive benefits adjustments merger order	**(30,674)**	(49,288)
Storm cost deferral	**66,708**	27,406
Other	**(50,072)**	(39,690)
Total Noncurrent Deferred Income Tax Liabilities	**2,019,456**	1,687,442
Less amounts classified as regulatory liabilities		
Deferred income taxes	**512,619**	486,507
Noncurrent Deferred Income Tax Liabilities	**$1,506,837**	$1,200,935
Deferred tax assets	**$408,821**	$486,424
Deferred tax liabilities	**2,233,803**	2,099,677
Net Accumulated Deferred Income Tax Liabilities	**$1,824,982**	$1,613,253

Iberdrola USA and its subsidiaries have the following loss carryforward amounts:
Federal - $100 million, state of New York - $785 million, Maine - $120 million, and Connecticut - $15 million. We have production tax credit carryforwards of $89 million. The loss carryforwards and production tax credits will expire between 2028 and 2032. Deferred tax assets are reduced by a valuation allowance when it is more likely than not that some portion or the entire deferred income tax asset will not be realized. We believe that it is more likely than not that we will produce sufficient taxable income in the future to realize all of our deferred income tax assets.

Reconciliation of Gross Income Tax Reserves (Thousands)	2012	2011
Balance as of January 1	**$25,695**	$32,710
Increases for tax positions related to prior years	**54,000**	14,856
Reduction for tax position related to settlements with taxing authorities	**(4,673)**	(21,871)
Balance as of December 31	**$75,022**	$25,695

The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not based on the technical merits that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the consolidated financial statements. The company has unrecognized income tax benefits of $75 million as of December 31, 2012, and $25.7 million as of December 31, 2011. Accruals for interest and penalties on tax reserves were $12.2 as of December 31, 2012 and $2.2 million as of December 31, 2011. The 2012 amounts were recognized as interest and the 2011 amounts were recognized as income taxes. If recognized, $27.9 million of the total gross unrecognized tax benefits would affect the effective tax rate. Gross income tax reserves increased $49.3 million in 2012 primarily due to increases for additional positions reserved in 2012 of $54.0 million offset by settlements with taxing authorities of $4.7 million.

We have been audited through 2005 for federal income taxes. The statute of limitations in all state jurisdictions except New York State has expired for all years through 2008. Our federal returns for 2006 through 2009 and New York State returns for 2007 through 2009 are currently under review. We anticipate that the reviews will be completed in 2013. It is reasonably possible that other events will occur during the next 12 months that would cause the total amount of unrecognized tax benefits to increase or decrease.

***Safe Harbor Method for capitalizing expenditures*:** In 2011 the Internal Revenue Service issued a revenue procedure to provide a safe harbor method of accounting that taxpayers may use to determine whether expenditures to maintain, replace or improve electric transmission and distribution property must be capitalized under Section 263 (a) of the Internal Revenue Code. The revenue procedure also provides procedures to obtain automatic consent to change to the safe harbor method of accounting. We used the safe harbor method in accounting for our 2011 and 2012 results.

***Capitalization of tangible assets*:** In December 2012 the Internal Revenue Service amended the temporary capitalization of tangible assets regulations previously issued in 2011, to be applicable to tax years beginning on or after January 1, 2014, unless the taxpayer elects to apply them in tax years beginning on or after January 1, 2012. We intend to review and comply with the final regulations, however we did not elect to apply the regulations in 2012.

***Bonus depreciation*:** As a result of the passage of The Small Business Jobs Act in September 2010 and the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 in December 2010, certain capital additions qualify for 50% bonus depreciation and 100% expensing, respectively, for tax purposes. Iberdrola USA and its affiliates have elected to apply the 50% bonus and 100% expensing to the additions it has determined qualify for accelerated tax depreciation. There is no earnings effect related to this election because the accelerated tax depreciation creates a temporary difference that requires the establishment of a deferred tax liability.

Notes to Consolidated Financial Statements

Note 5. Long-term Debt

At December 31, 2012 and 2011, our consolidated long-term debt was:

Company		Interest Rates	Maturity	Amount (Thousands) 2012	2011
	First mortgage bonds [1]				
RG&E	Series WW, VV, XX, YY & AAA	4.10% - 8.00%	2019 - 2033	**$600,000**	$600,000
RG&E	PCN 2004 Series A	4.75%	2016	**10,500**	10,500
RG&E	PCN 2004 Series B	5.375%	2032	**50,000**	50,000
RG&E	PCN Series C	5.00%	2016	**29,350**	29,350
CMP	Series A, B, C & D	3.07% - 5.70%	2019 - 2042	**525,000**	300,000
Total first mortgage bonds				**1,214,850**	989,850
	Unsecured pollution control notes (PCNs), fixed				
NYSEG	2011 Series A, B & D	2.125% - 2.250%	2015	**132,000**	132,000
NYSEG	1994 Series B & C	3.00%	2013	**101,000**	101,000
NYSEG	2004 Series B	5.35%	2028	**70,000**	70,000
NYSEG	2006 Series A	3.00%	2013	**12,000**	12,000
CMP	Industrial Development Authority of the state of New Hampshire Notes	5.375%	2014	**19,500**	19,500
Total unsecured pollution control notes, fixed				**334,500**	334,500
	Unsecured PCNs, variable				
NYSEG	2005 Series A	.13%	2026	**25**	25
NYSEG	2004 Series C	.577%	2034	**100,000**	100,000
RG&E	1997 Series A & B	.40%	2032	**68,000**	68,000
Total unsecured pollution control notes, variable				**168,025**	168,025
	Various long-term debt				
NYSEG	Unsecured Notes	3.24% - 6.15%	2016 - 2023	**650,000**	600,000
CMP	Series E & F Medium Term Notes	5.10% - 6.40%	2013 - 2037	**215,700**	268,200
Chester	Promissory and Senior Notes	7.05% - 10.48%	2020	**9,274**	10,457
Total various long-term debt				**874,974**	878,657
Obligations under capital leases				**11,667**	13,618
Unamortized premium on debt, net				**3,980**	3,985
				2,607,996	2,388,635
Less debt due within one year, included in current liabilities				**151,888**	155,637
Total Other long-term debt				**2,456,108**	2,232,998
	Long-term debt with affiliates				
Iberdrola USA	Unsecured Notes	5.90%	2013	**200,000**	300,000
Iberdrola USA	Unsecured Notes	7.08%	2019	**350,000**	350,000
				550,000	650,000
Less debt due within one year, included in current liabilities				**200,000**	-
Total Long-term debt with affiliates				**350,000**	650,000
Total Long-term Debt				**$2,806,108**	$2,882,998

[1] The first mortgage bonds are secured by liens on substantially all of the respective utility's properties.

In January 2012 NYSEG issued a notice to call $100 million of 5.5% unsecured notes due in November 2012 at a "make-whole" call price producing a yield of the treasury rate plus 25 basis points. The notes were redeemed in February 2012.

In September 2012 NYSEG issued $150 million of senior unsecured notes, of which $75 million will bear a coupon of 3.24% and mature in September 2022 and $75 million will bear a coupon of 4.55% and mature in September 2021.

In January 2012 CMP issued $100 million of Series C first mortgage bonds that bear a coupon of 5.68% and will mature in January 2042. In May 2012 CMP priced $125 million of Series D first mortgage bonds and $225 million of Series E first mortgage bonds. The series D bonds were issued in June 2012, bear a coupon of 3.07% and will mature in June 2022. The Series E bonds were issued in January 2013, bear a coupon of 4.45% and will mature in January 2043. The proceeds of these bonds were used to reduce short-term debt and to fund capital expenditures.

As of December 31, 2012 and 2011, NYSEG and RG&E had outstanding $573 million of tax-exempt PCNs, of which $252 million have coupons fixed to maturity, $113 million are notes with a mandatory redemption date in 2013, $40 million are notes with a mandatory redemption date in 2016, $100 million are 7-day auction rate notes and $68 million are 35-day auction rate notes. The notes with mandatory redemption dates in 2013 and 2016 have maturity dates in 2024 through 2032 and may be remarketed as tax-exempt bonds in a different interest rate mode after the mandatory redemptions.

In April 2009 the obligor on our $1.3 billion of outstanding unsecured debt was transferred to Iberdrola International, a subsidiary of Iberdrola S.A. In exchange we entered into a debt agreement with Scottish Power, Limited (Scottish Power), another subsidiary of Iberdrola S.A., for $1.05 billion and received an equity infusion of $250 million from Iberdrola S.A. In May 2009 we borrowed an additional $300 million from Scottish Power. In 2010 we repaid $700 million of the debt. In September 2012 we repaid an additional $100 million at a premium of $2.6 million included in other deductions. Our outstanding balance with Scottish Power as of December 31, 2012, was $550 million, which includes $200 million in current maturities.

At December 31, 2012, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years is:

2013	2014	2015	2016	2017
$351,888	$22,759	$134,642	$182,054	$202,025

***Cross-default provisions*:** Iberdrola USA has a provision in its revolving credit facility, which provides that its default with respect to any other debt in excess of $50 million will be considered a default under its revolving credit facility.

We are in compliance with all debt covenants as of December 31, 2012 and 2011.

Notes to Consolidated Financial Statements

Note 6. Bank Loans and Other Borrowings

Our regulated operating utilities rely on a combination of bank provided and intercompany revolving credit facilities to fund short-term liquidity needs. In July 2011 NYSEG, RG&E and CMP jointly entered into a bank provided revolving credit facility (the "Joint Facility") that allows maximum borrowings of up to $600 million in aggregate and expires in 2016. Sublimits that total to the aggregate limit apply to each joint borrower and can be altered within the constraints imposed by maximum limits that apply to each joint borrower. Each borrower pays a facility fee ranging from 20 to 25 basis points annually depending on the rating of its unsecured debt.

In February 2012 CMP and NYSEG established commercial paper programs with limits of $350 million and $200 million respectively. The Joint Facility serves as the backstop to these programs. The companies intend to use commercial paper as an alternative to revolving credit facilities as source of short-term credit.

In May 2012 Iberdrola USA executed a $300 million revolving credit facility with a syndicate of nine banks. Under the agreement Iberdrola USA is the sole borrower and may borrow up to $300 million. This facility expires in May 2017. Iberdrola USA pays a facility fee of 22.5 basis points annually. In addition, Iberdrola USA is the borrower on a $600 million intercompany revolving credit facility in which Iberdrola Financiacion S.A.U., a subsidiary of Iberdrola S.A., is the lender. This agreement expires in 2016 and Iberdrola USA pays a facility fee of 25 basis points. Iberdrola USA uses these facilities to fund its own liquidity needs, the liquidity needs of its unregulated subsidiaries and affiliates and to fund draws on the supplemental intercompany revolving credit facilities with the regulated operating utilities. Federal and state regulatory restrictions limit our ability to borrow funds from our utility subsidiaries. While we may be able to borrow funds from our utility subsidiaries by obtaining regulatory approvals and meeting certain conditions, we do not expect to seek such loans. Iberdrola USA has no secured indebtedness and none of its assets are mortgaged, pledged or otherwise subject to lien. None of Iberdrola USA's debt obligations are guaranteed or secured by its subsidiaries.

There was $179 million of short-term debt outstanding at December 31, 2012, and $75 million outstanding at December 31, 2011. The weighted-average interest rate on short-term debt was 0.39% at December 31, 2012, and 0.7% at December 31, 2011. At January 31, 2013, there was $130 million of short-term debt outstanding.

In our revolving credit facility we covenant not to permit, without the consent of the lender, our ratio of consolidated indebtedness to consolidated total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to consolidated total capitalization, the facility excludes from consolidated net worth the balance of Accumulated other comprehensive income (loss) as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness Iberdrola USA may maintain. Continued unremedied failure to comply with those covenants for 15 days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of consolidated indebtedness to consolidated total capitalization pursuant to the revolving credit facility was 0.47 to 1.00 at December 31, 2012. We are not in default as of December 31, 2012.

In the joint facility each joint borrower covenants not to permit, without the consent of the lender, its ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to total capitalization, the facility excludes from consolidated net worth the balance of Accumulated other comprehensive income (loss) as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness each borrower may maintain. Continued unremedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity for the party in default. We are not in default as of December 31, 2012.

Note 7. Redeemable Preferred Stock of Subsidiaries, Noncontrolling Interests

The redeemable preferred stock of subsidiaries are noncontrolling interests because they contain a feature that allows the holders to elect a majority of the subsidiary's board of directors if preferred stock dividends are in default in an amount equivalent to four full quarterly dividends. Such a potential redemption-triggering event is not solely within the control of the subsidiary.

On June 22, 2012, CMP redeemed all of its outstanding shares of the 4.60% series and 4.75% series at a price of $101.00 per share plus accrued dividends from April 1, 2012, to the date of redemption.

On June 22, 2012, NYSEG redeemed all of its outstanding shares of the securities listed below at the redemption prices indicated plus accrued dividends from April 1, 2012, to the date of the redemption.

On September 26, 2012, CMP Group, Inc. made a tender offer to purchase all of the outstanding shares of CMP's 6% preferred stock at $110.00 per share plus an amount equal to any accrued but unpaid dividends up to but not including the settlement date. The tender offer expired on November 15, 2012.

At December 31, 2012 and 2011, our consolidated redeemable preferred stock, noncontrolling interests was:

Subsidiary and Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding[1]	Amount (Thousands) 2012	2011
CMP, 6% Noncallable	$100	-	1,921	**$192**	$235
CMP, 4.60%	100	101.00	-	**-**	1,167
CMP, 4.75%	100	101.00	-	**-**	903
NYSEG, 3.75%	100	104.00	-	**-**	7,838
NYSEG, 4.50% (1949)	100	103.75	-	**-**	1,180
NYSEG, 4.40%	100	102.00	-	**-**	709
NYSEG, 4.15% (1954)	100	102.00	-	**-**	432
NYSEG, Limited Voting Junior	1	-	1	**-**	-
RG&E Limited Voting Junior	1	-	1	**-**	-
Total				**$192**	$12,464

[1]At December 31, 2012, Iberdrola USA and its subsidiaries had 6,755,000 shares of $100 par value preferred stock, 14,800,000 shares of $25 par value preferred stock, 1,000,000 shares of $100 par value preference stock and 5,000,000 shares of $1 par value preference stock authorized but unissued.

Note 8. Tax Equity Investments

In April 2009 Iberdrola USA, through its subsidiary CNE Energy, acquired an interest in Aeolus Wind Power V LLC (Aeolus V) in exchange for $305.4 million in cash. CNE Energy purchased its membership interest in Aeolus V from PPM Wind Energy LLC (PPM), an affiliate, which contributed its 100% ownership of various wind farms to Aeolus V.

The main characteristics of our investment in Aeolus V are as follows:

- PPM retains day-to-day management of the wind farms. Defined major decisions require consent from CNE Energy.

Notes to Consolidated Financial Statements

- As a minority shareholder, CNE Energy has the right to a substantial portion of the profits and tax credits generated by the wind farms up to the return level established at the beginning of the investment contract.
- CNE Energy initially holds a 50% interest in Aeolus V until it achieves a stipulated 7.5% return, after which it is entitled to maintain a 5% ownership interest.
- PPM has the option to purchase, at fair market value, CNE Energy's remaining residual equity interest, which is exercisable after CNE Energy achieves its agreed upon return.
- Whether or not CNE Energy obtains the agreed upon return depends on the economic performance of the wind farms. While PPM is bound to operate and maintain the facilities in an efficient manner and maintain appropriate insurance, it is not obligated to deliver cash to CNE Energy over and above the aforementioned profits and tax credits.

On December 17, 2010, we acquired, also through CNE Energy, an interest in Aeolus Wind Power VI LLC (Aeolus VI) in exchange for $236 million in cash. CNE Energy purchased its membership interest in Aeolus VI from PPM, which contributed its 100% ownership of four wind farms to Aeolus VI. The partnership terms for Aeolus VI are similar to the terms described above for Aeolus V.

CNE Energy uses an equity method referred to as Hypothetical Liquidation at Book Value (HLBV) to account for its investments in Aeolus V and in Aeolus VI. The application of that method results in CNE Energy recording a gain or loss on its investment based on the cash implications of a liquidation at book value, with a corresponding adjustment to the investment account. In addition, the HLBV method requires the tax effects related to Production Tax Credits (PTCs) (applies to Aeolus V only) and taxable income (loss) to be recorded in income taxes on the income statement. The primary difference in accounting for the Aeolus VI investment is that the Aeolus VI wind farms received cash grants from the federal government and consequently are not eligible for PTCs. Finally, the HLBV method requires a credit to accumulated deferred income taxes on the balance sheet and a debit to income taxes on the income statement for an amount representing the statutory rate applied to the difference between the tax basis and the book basis of the investment.

The following table shows the effects of our investments on our consolidated income statements and balance sheets:

Income statement for the year ended December 31,	**2012**	**2011**
(Thousands)		
Other (deductions), losses from tax equity investments	$(4,540)	$(57,157)
Income tax (benefit)	(26,611)	(83,438)
Total income statement benefit	$22,071	$26,281

Balance sheet at December 31,	**2012**	**2011**
(Thousands)		
Tax equity investment	$416,319	$420,858
Deferred tax liabilities, noncurrent	(157,454)	$(30,629)
Deferred tax liabilities, current	$119,284	-

The following table provides summary financial information for Aeolus V and Aeolus VI:

Income statement for the year ended December 31,	2012	2011
(Thousands)		
Revenues*	$118,405	$117,983
Operating (Loss)	$(6,645)	$(4,490)
Net (Loss)	$(29,738)	$(30,338)

*Including PTCs for Aeolus V only.

Balance sheet at December 31,	2012	2011
(Thousands)		
Total Assets	$2,455,315	$2,043,390
Total Equity	$1,523,075	$1,546,196

Note 9. Commitments and Contingencies

***Capital spending*:** We have commitments in connection with our capital spending program. As part of the rate plans approved for NYSEG and RG&E in August 2010, capital spending targets were established. The aggregate capital expenditure target for the two companies is $397 million for 2013. If at the end of the rate plan in 2013 the revenue requirement on net plant has been lower than that assumed in the rate plans based on that capital expenditure level, the companies will defer the revenue requirement impact for the benefit of customers.

On June 10, 2010, the Maine Public Utilities Commission granted approval for CMP's Maine Power Reliability Program (MPRP). The MPRP, expected to be completed in 2015, is a $1.4 billion project that will support the development of new renewable energy resources and help ensure long-term reliability for customers by increasing the capacity and efficiency of the New England transmission grid. The MPRP includes the construction of five new 345-kilovolt substations and related facilities linked by approximately 450 miles of new or rebuilt transmission lines. The costs for the MPRP project as of December 31, 2012, totaled approximately $871 million with $307 million included in Utility Plant and $564 million included in CWIP.

***CMP customer charge-offs*:** Under Maine electric restructuring law, Maine electric delivery utilities are required to bill customers for delivery and supply service. This includes managing delivery and supply accounts receivable and uncollectibles. In October 2010 the MPUC initiated a proceeding to investigate CMP's credit and collection practices, and, in particular, whether CMP complies with the MPUC's new credit and collection rules, including the treatment of unpaid customer balances for delivery charges and supply charges.

MPUC Staff issued its Bench Analysis on March 14, 2011. Concerning the treatment of unpaid customer balances for delivery and supply charges, the Bench Analysis took the position that CMP's process of applying deposits to finaled accounts has disproportionately credited delivery receivables over supply receivables. The Bench Analysis also criticized CMP for the increase in accounts receivable. Taking all of those factors collectively into account, but not attributing any specific amount to any particular cause, the Bench Analysis concluded that CMP's rate of charge-offs for supply receivables should have been comparable to its rate of delivery charge-offs during this period. Based on that conclusion, the Bench Analysis contended that $10.6 million of standard offer receivables should be retroactively reclassified to delivery receivables and the supply offer retainage account should be credited accordingly.

On August 24, 2012, the Hearing Examiner issued a report and recommended decision in the case, recommending that the MPUC order CMP to retroactively reallocate $2.6 million of customer deposits, previously applied to CMP's delivery service receivables during the period 2008 through 2010 as a credit to Standard Offer Service receivables. The Examiner's Report also recommended that the MPUC find CMP's collections practices during the period 2005 through 2010 were imprudent, resulting in an additional recommended disallowance of $3.7 million. In total, the Examiner's Report recommended that the MPUC order CMP to credit the Standard Offer Service retainage account by $6.3 million at CMP's expense. On September 14, 2012, CMP filed its exceptions to the Examiner's Report, arguing that the Examiner's recommendations constitute illegal, retroactive, single-issue ratemaking and that the Examiner has failed to meet the burden of proof necessary to support a finding of imprudent utility behavior. On October 4, 2012, the MPUC deliberated the matter and agreed with the Hearing Examiner's recommendation to require CMP to retroactively reallocate $2.6 million of customer deposits. The MPUC also agreed with the Hearing Examiner's finding of imprudent behavior with respect to appropriately pursuing customer collections during the period of 2008 through 2010. The MPUC determined that this imprudent behavior resulted in additional harm of $1.5 million and CMP should therefore credit a total of $4.1 million to Standard Offer Service receivables. On January 25, 2013, the MPUC issued its written Order confirming the $4.1 million credit to the standard offer retainage account. CMP is reviewing the Order to determine whether it will ask for further review. In December 2012 CMP reallocated $5.1 million in customer receivables with an associated charge to operating expense.

***Homer City*:** In June 2008 NYSEG received a letter from subsidiaries of Edison Mission Energy (EME) regarding a notice of violation (NOV) from the U. S. Environmental Protection Agency (EPA) claiming that certain modifications to the Homer City Electric Generation Station (Homer City) during the time it was owned by NYSEG and Pennsylvania Electric Company (Penelec) were done in violation of EPA's new source review regulations. NYSEG and Penelec sold Homer City to EME in 1999. EME asserts that it is entitled to indemnification for certain fines, penalties and costs arising out of the violations alleged in the NOV under the terms of the Asset Purchase Agreement for Homer City. This appears to be the same claim EME made to NYSEG and Penelec in October 2000. NYSEG continues to believe that the costs sought by EME are not liabilities of NYSEG and that NYSEG did not retain liability for these material claims when the plant was sold.

In connection with this matter, in January 2011 the U. S. Justice Department filed a lawsuit on behalf of the EPA in the U.S. District Court for the Western District of Pennsylvania against current and former owners and operators of Homer City. NYSEG and Penelec are named in the suit, along with EME Homer City Generation, the current operator, and eight limited liability companies that own the plant by virtue of a sale and leaseback refinancing that occurred in 2001. NYSEG believes it has a number of sound defenses to the claims included in the lawsuit, including that the statute of limitations and equitable principles prohibit EPA from forcing NYSEG to pay for costly improvements at a plant it has not owned or operated in over 10 years. NYSEG and all other defendants filed a motion to dismiss the complaint, which was granted by the judge in October 2011. The EPA has appealed the decision. The judge's dismissal of the case bolsters our assessment that NYSEG does not face significant liability from this case. NYSEG, however, cannot predict the ultimate outcome of this matter.

***Merger order*:** The Iberdrola Merger Order contained a capital expenditure condition for NYSEG and RG&E for an aggregate of $540 million during 2009 and 2010. In September 2009 NYSEG and RG&E requested a limited waiver of the capital expenditure merger condition to allow them to spend the capital investment by 2011. The request was denied by the New York Public Service Commission (NYPSC) in its April 2010 Order. If NYSEG and RG&E were to spend less than the amount targeted in the merger order, they would be obligated to provide a calculation of the carrying charge revenue requirement effect resulting from the actual level of capital spending compared to the targeted amount, which could be returned to customers if ordered by the NYPSC.

Notes to Consolidated Financial Statements

NYSEG and RG&E made a filing in January 2011 in which they showed that capital spending during 2009 and 2010 was approximately $359 million for NYSEG and approximately $188 million for RG&E. As part of the same filing, they provided an assessment of other considerations, including the effects on customers associated with a lower level of capital spending during 2009, and provided reasons why the total revenue requirement effect, as calculated, should not be returned to customers.

The NYPSC issued an order in November 2011 directing each company to record a deferred credit on behalf of customers due to the timing of the 2009 and 2010 capital expenditures: $6.8 million for NYSEG and $10.0 million for RG&E. As required by the order, the deferred credits will not accrue any additional carrying charges prior to their ultimate disposition to ratepayers. Disposition of the credits will occur after the end of the existing rate plan (after 2013). The order also allowed NYSEG to reflect approximately $3.5 million per year, for a three year period beginning in 2011, of shareholder deferred carrying charges on certain capital expenditures.

In December 2011 NYSEG and RG&E filed a Petition for Rehearing of the NYPSC November Order, asking the NYPSC to reconsider the imposition of the carrying charge deferred credit, since NYSEG had spent above the targeted level during the 2009 to 2010 time period and since the benefits to ratepayers of RG&E's deferred spending had not been considered in the NYPSC November 2011 Order. On May 4, 2012, the NYPSC issued an Order Denying Rehearing and Granting Clarification in Part. The NYPSC did not grant any relief on its determination of the customer credit amounts, but did clarify that 2010 incremental project costs will be recognized in meeting the annual net plant targets.

***New England Transmission Owners Allowed Rate of Return*:** CMP's transmission rates are determined by a tariff regulated by the FERC and administered by ISO-NE. Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, as well as return of and on investment in transmission assets. The FERC provides base return on equity (ROE) and additional incentive adders applicable to assets based upon vintage, voltage and other factors.

Pursuant to a FERC incentive rate order, CMP is provided a 12.89% ROE and allowed to include the CWIP related to the MPRP in rates, subject to an annual reconciliation.

In September 2011 the Massachusetts Attorney general and other state officials filed a complaint with the FERC that the ISO-NE base ROE for transmission owners in New England is too high and should be lowered. CMP is a member of the New England Transmission Owners (NE-TOs). The current base ROE is 11.14%. The complaint requests that the FERC reduce the NE-TO's allowed base ROE by 1.94% to a value of 9.2%. If this relief is granted, effective with the date of the complaint, CMP would be required to refund approximately $24 million for the period October 1, 2011, to December 31, 2012, to its wholesale and retail transmission customers. The NE-TOs disagree with the complaint, are requesting dismissal, and filed testimony supporting their position that the existing rate is reasonable. In May 2012 the FERC issued an order setting the complaint for hearing and directing the matter to settlement judge procedure. Following designation of a settlement judge, an initial settlement conference was convened in May 2012 and settlement discussions ensued. In August 2012 the FERC settlement judge declared the parties to be at an impasse and terminated settlement proceedings. A litigation schedule to resolve the complaint has been established and a decision by the FERC is expected in late 2013 or early 2014. We cannot predict the outcome of this proceeding.

***Nonutility generator power purchase contracts*:** We expensed approximately $66 million for NUG power in 2012 and $74 million in 2011. We estimate that our NUG power purchases will total $79 million in 2013; $77 million in 2014, 2015 and 2016; and $19 million in 2017.

Notes to Consolidated Financial Statements

***Nuclear entitlement power purchase contracts*:** In connection with our sales of nuclear generating assets in 2001 and 2004, we entered into four entitlement contracts under which we purchase electricity at a fixed contract price. We expensed approximately $191 million for nuclear entitlement power in 2012 and $260 million in 2011. We estimate that our nuclear entitlement power purchases will be $203 million in 2013, $87 million in 2014 and $3 million in 2015.

***CMP Storm Costs*:** Under its distribution service 2008 Alternative Rate Plan (ARP 2008), CMP is allowed to recover restoration costs for major storms meeting established qualification criteria. In 2011 we requested recovery of $17.4 million of deferred storm restoration costs resulting from two large storms in February 2010 and November 2010. Through a negotiated settlement, an increase in prices reflective of a 36-month recovery of the requested amount was allowed to become effective, subject to further review and potential refund or adjustment in the recovery period. The MPUC Staff had raised concerns regarding the qualification of the November storm as a major storm event, as well as the prudence of certain restoration costs incurred in the February storm. In June 2012 the MPUC concluded that all of CMP's 2010 storm restoration costs were prudently incurred and qualified for rate recovery under the terms of ARP 2008.

Yankee Decision in DOE Litigation: CMP has an ownership interest in three nuclear generating companies (the Yankee companies) that have been decommissioned and currently store spent nuclear fuel (SNF) on their sites. On May 18, 2012, the U.S. Court of Appeals issued a favorable decision in the Yankee companies' ongoing litigation over the U.S. Department of Energy's failure to remove SNF from the three New England single-unit decommissioned nuclear reactor sites as required by contract and the Nuclear Waste Policy Act beginning in 1998. Damages awarded to the three companies totaled nearly $160 million. CMP's share of the award is approximately $37 million.

The Yankee companies received the awards in early 2013. The awards will be used to offset future costs of spent fuel storage which are borne by the owners, with any excess being credited to the owners. Any reduction in CMP's costs, or refunds received by CMP, will be passed on to its retail customers through its stranded cost rates. As a result of these actions our liability to the Yankee companies at December 31, 2012, reflects a reduction of $12 million, with an offsetting reduction in regulatory assets. We have not established an asset for any future receivables.

***NYPSC Staff Review of Earnings Sharing Calculations and other Regulatory Deferrals*:** In December 2012 the NYPSC Staff informed NYSEG and RG&E that the Staff had conducted an audit of the companies' annual compliance filings (ACF) for 2009 through August 31, 2010, and the first rate year of the current rate plan (September 1, 2010 to August 31, 2011). The NYPSC Staff's preliminary findings indicate adjustments to deferred balances, primarily associated with storm costs, as well as treatment of certain incentive compensation costs for purposes of the 2011 ACF. The Staff's findings approximate $9.8 million of adjustments to deferral balances and customer earnings sharing accruals. NYSEG & RG&E have been reviewing the Staff's adjustments and workpapers and will provide a response to the Staff in 2013. As a result of the Staff report NYSEG & RG&E recorded a $3.4 million reserve in December 2012 in anticipation of settling the issues.

***New York State Tax Audit*:** During July 2012, the Company was notified by the State of New York that it would be pursuing the de-combination of the New York filing group beginning with the 2007 tax year. While the company believes that the combined filing is appropriate, the final outcome of the NYS audit is uncertain. An unfavorable resolution would require the company to incur a Subsidiary Capital tax, as well as an Income Tax. As a result, the company recorded a charge to other taxes of $20 million in 2012 for the estimated Subsidiary Capital tax impact of the de-combination. We are assessing various mitigation strategies in order to minimize the

Subsidiary Capital Tax in the future, in the event that de-combination is sustained. The maximum combined net income impacts related to the subsidiary capital tax, current income tax, deferred income tax and interest associated with this audit is $63 million. The company will continue to challenge the assessment, and believes it has adequate reserves to cover any final determination.

Note 10. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric and natural gas service.

The EPA and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at 22 waste sites. The 22 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 22 sites, 13 sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites, four are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and eight sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $1 million related to seven of the 22 sites. We have paid remediation costs related to the remaining 15 sites, and do not expect to incur any additional liability. We have recorded an estimated liability of $5 million related to another 13 sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties or are regulated under State Resource Conservation and Recovery Act (RCRA) programs. It is reasonably possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us.

We have a program to investigate and perform necessary remediation at our 52 sites where gas was manufactured in the past. Eight sites are included in the New York State Registry, eight sites are included in the New York Voluntary Cleanup Program, three sites are part of Maine's Voluntary Response Action Program and of those, two sites are part of Maine's Uncontrolled Sites Program. We have entered into consent orders with various environmental agencies to investigate and, where necessary, remediate 44 of the 52 sites.

Our estimate for all costs related to investigation and remediation of the 52 sites ranges from a minimum of $180 million to $361 million at December 31, 2012. Our estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $180 million at December 31, 2012, and $193 million at December 31, 2011. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from FirstEnergy described below, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis unless payments are fixed and determinable. Nearly all of our environmental liability accruals, which are expected to be paid through the year 2030, have been established on an undiscounted basis.

Notes to Consolidated Financial Statements

NYSEG sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) to recover environmental clean-up costs at 16 former manufactured gas plants. On July 11, 2011, the United States District Court for the Northern District of New York issued a decision and order in NYSEG's favor. Based upon past and future clean-up costs at the 16 sites in dispute, FirstEnergy will be required to pay NYSEG approximately $60 million if the decision, as written, is upheld on appeal. FirstEnergy appealed the decision to the Second Circuit Court of Appeals, a process estimated to take approximately two years to complete. On September 9, 2011, FirstEnergy paid NYSEG $29.7 million, representing their share of past costs ($26.5 million) and pre-judgment interest ($3.2 million). If FirstEnergy succeeds in overturning the decision, NYSEG must return that payment. Our opinion is that it is less than probable that we will have to refund any of the $29.7 million and we have not recorded a contingency for that amount. The payment has been recorded as a reduction in the regulatory asset for environmental remediation.

Note 11. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet.

The financial instruments we hold or issue are not for trading or speculative purposes.

Commodity price risk: Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging activities.

NYSEG and RG&E have a nonbypassable wires charge adjustment that allows them to pass through rates any changes in the market price of electricity. They use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2012, the loss recognized in regulatory assets was $8.5 million for electricity derivatives. For the year ended December 31, the loss reclassified from regulatory assets into income, which is included in electricity purchased, was $28.4 million for 2012 and $3.6 million for 2011.

NYSEG and RGE have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. NYSEG and RG&E use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2012, the loss recognized in regulatory assets was $1.6 million for natural gas hedges. For the year ended December 31, the loss reclassified from regulatory assets into income, which is included in natural gas purchased, was $12.1 million for 2012 and $14.7 million for 2011.

Energetix, Inc. and NYSEG Solutions, Inc. (sold in 2012) designated financial electricity contracts as cash flow hedging instruments. We record changes in the fair value of the cash flow hedging instruments in other comprehensive income (OCI), to the extent they are considered effective, and reclassify those gains or losses into earnings in the same period or periods during which the hedged transactions affect earnings. We record the ineffective portion of any change in fair value of cash flow hedges to the income statement as either Other (Income) or Other Deductions, as appropriate.

Our derivative volumes by commodity type that are expected to settle each year are:

	Electricity Contracts	**Natural Gas Contracts**	**Other Fuel Contracts**
Year to settle	**Financial Mwhs**	**Financial Dths**	**Financial Gals**
As of December 31, 2012			
2013	2,511,225	2,860,000	3,066,500
2014	955,900	640,000	-
As of December 31, 2011			
2012	5,666,658	8,739,632	1,748,500
2013	1,505,770	999,068	-
2014	5,138	-	-

Notes to Consolidated Financial Statements

The location and amounts of derivative fair values in the balance sheet are:

	Asset Derivatives		Liability Derivatives	
As of December 31,	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
(Thousands)				
Derivatives designated as hedging instruments				
2012				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	**-**	Current liabilities	**$(8,489)**
Long-term	Other assets	**-**	Other liabilities	**(42)**
Natural gas derivatives:				
Current	Current assets	**-**	Current liabilities	**(1,492)**
Long-term	Other assets	**-**	Other liabilities	**(125)**
Other contracts:	Current assets	**-**	Current liabilities	**(769)**
Total		**-**		**$(10,917)**
2011				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	-	Current liabilities	$(25,876)
Long-term	Other assets	$158	Other liabilities	(7,431)
Natural gas derivatives:				
Current	Current assets	-	Current liabilities	(13,746)
Long-term	Other assets	-	Other liabilities	(915)
Other contracts:	Current assets	-	Current liabilities	(615)
Total		$158		$(48,583)

Notes to Consolidated Financial Statements

The effect of hedging instruments on OCI and income was:

Year Ended December 31,	Gain (Loss) Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain (Loss) Reclassified from Accumulated OCI into Income	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives
Derivatives in Cash Flow Hedging Relationships	**Effective Portion (1)**	**Effective Portion (1)**		**Ineffective Portion (2)**	
(Thousands)					
2012					
Interest rate contracts	**-**	Interest expense	**$(9,329)**	Interest expense	**-**
Commodity contracts:					
Electricity derivatives	**$5,464**	Electricity purchased	**3,531**	Other (Income)/ Other Deductions	**$(121)**
Natural gas	**5,755**	Natural gas purchased	**(3,255)**	-	**-**
Other	**(416)**	Other direct costs	**262**	-	**-**
Total	**$10,803**		**$(8,791)**		**$(121)**
2011					
Interest rate contracts	-	Interest expense	$(9,329)	-	-
Commodity contracts:					
Electricity derivatives	$(22,561)	Electricity purchased	5,017	Other (Income)/ Other Deductions	$120
Natural gas	277	Natural gas purchased	(2,399)	-	**-**
Other	20	Other direct costs	(730)	-	-
Total	$(22,264)		$(7,441)		$120

(1) Changes in OCI are reported in after-tax dollars.
(2) Ineffective portion of power supply contracts that are designated as cash flow hedges.

The amount in AOCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2012, is a net loss of $121 million as compared to a net loss of $130.3 million for 2011. For the year ended December 31, 2012, we reported $9.3 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $9.3 million of discontinued cash flow hedges in 2013.

At December 31, 2012, $0.8 million in losses are reported in OCI because the forecasted transaction is considered to be probable. We expect that those losses will be reclassified into earnings within the next 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions.

NYSEG and RG&E face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally Moody's or S&P). When our exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract. For financial statement presentation, we do not offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement. Under the master netting arrangements our obligation to return cash collateral was $1.6 million at December 31, 2012 and 2011.

Certain of our derivative instruments contain provisions that require us to maintain an investment grade credit rating on our debt from each of the major credit rating agencies. If our debt were to fall below investment grade, it would be in violation of those provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2012, is $10.9 million for which we have posted collateral of $8.5 million in the normal course of business. If the credit-risk-related contingent features underlying those agreements were triggered on December 31, 2012, we would be required to post an additional $2.4 million of collateral with our counterparties.

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The carrying amounts and estimated fair values of our financial instruments are shown in the following table. Carrying amounts include related debt premiums and discounts.

December 31,	**2012**		**2011**	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
(Thousands)				
First mortgage bonds	**$1,214,057**	**$1,611,937**	$989,004	$1,209,021
Pollution control notes, fixed	**$334,500**	**$335,911**	$341,554	$345,210
Pollution control notes, variable	**$168,025**	**$158,895**	$168,025	$148,415
Various long-term debt	**$879,747**	**$1,053,618**	$876,434	$1,038,957
Long-term debt owed to affiliates	**$550,000**	**$652,338**	$650,000	$758,710

The carrying amounts for cash and cash equivalents, accounts receivable, notes payable and interest accrued approximate their estimated fair values.

We value all fixed rate long-term debt, whether unsecured or secured by a first mortgage lien, taxable or tax-exempt, by assigning a market-based yield for each security and then deriving the price from the yield. Market-based yields are determined by observing secondary market trading levels for debt of similar maturity, rating, tax and structural characteristics. We value all variable rate debt at par as it approximates fair value, except for the auction rate securities issued by RG&E, which do not have an active market.

Notes to Consolidated Financial Statements

Assets and liabilities measured at fair value on a recurring basis

		Fair Value Measurements at December 31, Using		
Description	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2012				
Assets				
Noncurrent investments available for sale, auction rate securities	**$2,700**	**-**	**-**	**$2,700**
Noncurrent investments available for sale, other	**37,091**	**$37,091**	**-**	**-**
Total	**$39,791**	**$37,091**	**-**	**$2,700**
Liabilities				
Derivatives				
Commodity contracts:				
Electric	**$8,531**	**$8,531**	**-**	**-**
Natural gas	**1,617**	**1,617**	**-**	**-**
Other	**769**	**-**	**-**	**$769**
Total	**$10,917**	**$10,148**	**-**	**$769**
2011				
Assets				
Noncurrent investments available for sale, auction rate securities	$2,700	-	-	$2,700
Noncurrent investments available for sale, other	39,558	$39,558	-	-
Derivatives				
Commodity contracts:				
Electricity	158	-	-	158
Total	$42,416	$39,558	-	$2,858
Liabilities				
Derivatives				
Commodity contracts:				
Electricity	$33,307	$24,153	-	$9,154
Natural gas	14,661	14,661	-	-
Other	615	-	-	615
Total	$48,583	$38,814	-	$9,769

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2012 and 2011. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Notes to Consolidated Financial Statements

Valuation techniques: We measure the fair value of our noncurrent investments available for sale, auction rate securities based on the estimated probabilities of when the auction rate markets would return to historic interest rate levels and include the measurements in Level 3.

We measure the fair value of our noncurrent investments available for sale, other using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments primarily consist of money market funds.

We determine the fair value of our various derivative assets and liabilities utilizing market approach valuation techniques:

- NYSEG and RG&E enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. They hedge their electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. NYSEG and RG&E hedge all of their electric load obligations in a NYISO location where an active market exists. The forward market prices used to value their open electric energy derivative contracts are readily available with no adjustment required and we include the fair value in Level 1.
- NYSEG and RG&E enter into natural gas derivative contracts to hedge the forecasted purchases required to serve their natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.

Instruments measured at fair value on a recurring basis using significant unobservable inputs

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Auction Rate Securities	**Derivatives, Net**	**Total**
Balance, January 1, 2011	$2,700	$8,659	$11,359
Total (losses) gains (realized/unrealized)			
Included in earnings	-	4,407	4,407
Included in other comprehensive income	-	(22,541)	(22,541)
Purchases	-	(136)	(136)
Balance, December 31, 2011	2,700	(9,611)	(6,911)
Total (losses) gains (realized/unrealized)			
Included in earnings	**-**	**3,793**	**3,793**
Included in other comprehensive income	**-**	**5,049**	**5,049**
Balance, December 31, 2012	**$2,700**	**$(769)**	**$1,931**
Total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at December 31,			
2011	-	$120	-
2012	**-**	**$(121)**	**-**

Notes to Consolidated Financial Statements

The gains and losses included in earnings for the period (above), which are reported in the various categories indicated are:

	Electricity purchased	Other operating expense	Other income
(Thousands)			
Total gains (losses) included in earnings for year ended December 31,			
2011	$5,017	$(730)	$120
2012	**$3,652**	**$212**	**$(121)**

Asset measured at fair value on a nonrecurring basis

		Fair Value Measurement at December 31, Using			
Description	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total Loss Year Ended December 31,**
(Thousands)					
2012					
Asset held for sale					
Carthage generating station	**$1,104**	**-**	**-**	**$1,104**	**$(3,394)**
2011					
Long-lived asset held and used					
Carthage generating station	$4,844	-	-	$4,844	$(2,723)

On December 17, 2012, we received two bids in connection with the sale of certain fossil fuel generation assets (see Note 17). Management determined it was appropriate to write down the value of the Carthage generating station assets, owned by Cayuga Energy, Inc., to the amount of the best bid of $1.1 million, resulting in a pretax impairment loss of $3.4 million. In 2011 we wrote down the Carthage assets, then classified as held and used, to their fair value of $4.8 million in accordance with the provisions for impairment of long-lived assets. That write-down resulted in a pretax impairment loss of $2.7 million. The impairment losses for both years are included in discontinued operations for the relevant period.

<u>Valuation technique</u>: We determined the fair value of the Carthage assets as of December 31, 2012, based on the best bid of $1.1 million and have included the measurement in Level 3. We determined the fair value of Carthage as of December 31, 2011, using an income approach – based on discounted cash flows – and included the measurement in Level 3. On an undiscounted basis there would have been no impairment if we continued to assume the plant would be held throughout its life. However, because we assumed that the plant would be sold (see Note 17), we discounted the cash flows as a proxy for the auction value of the plant. The key assumption was the projected capacity values, which had declined significantly since 2009 and were well below the cost of new capacity. The lower values, based on market quotes, were expected to last through 2014. There were no reliable forecasts for capacity values for years beyond 2014. During 2011 we developed internally various capacity value forecasts. Those forecasts attempted to reflect such factors as the marginal cost of new capacity and the anticipated shutdowns of major plants, which should increase capacity values. Because no forecast was more reasonable, we

used a simple average of the forecasts. Other assumptions had less of an effect on the final results such as the amount of actual generation, which had varied significantly in the past but had little effect because of the very low margin resulting from those sales.

Note 13. Accumulated Other Comprehensive Income (Loss)

(Thousands)	Balance January 1, 2011	2011 Change	Balance December 31, 2011	2012 Change	Balance December 31, 2012
Net unrealized holding (loss) gain on investments, net of income tax benefit (expense) of $209 for 2011 and $(228) for 2012	$(45)	$(164)	$(209)	$344	$135
Amortization of pension cost for nonqualified plans, net of income tax (expense) of $(889) for 2011 and $(160) for 2012	(8,818)	1,126	(7,692)	277	(7,415)
Unrealized (loss) gain on derivatives qualified as hedges:					
Unrealized (loss) gain during period on derivatives qualified as hedges, net of income tax benefit (expense) of $4,611 for 2011 and $(3,676) for 2012		(14,960)		6,673	
Reclassification adjustment for (gain) loss included in net income, net of income tax expense (benefits) of $273 for 2011 and $(397) for 2012		(411)		595	
Net unrecognized gain on settled cash flow treasury hedges, net of income tax benefits of $(3,775) for 2011 and $(3,713) for 2012		5,554		5,617	
Net unrealized (loss) gain on derivatives qualified as hedges	(76,341)	(9,817)	(86,158)	12,885	(73,273)
Accumulated Other Comprehensive (Loss) Income	$(85,204)	$(8,855)	$(94,059)	$13,506	$(80,553)

No Accumulated Other Comprehensive Income (Loss) is attributable to the noncontrolling interests for the above periods.

Notes to Consolidated Financial Statements

Note 14. Retirement Benefits

We have funded noncontributory defined benefit pension plans that cover substantially all of our employees. The plans provide defined benefits based on years of service and final average salary. We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

***Obligations and funded status*:**

	Pension Benefits		Postretirement Benefits	
	2012	**2011**	**2012**	**2011**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$2,317,916**	$2,206,420	**$473,218**	$471,412
Service cost	**30,800**	28,766	**4,240**	4,727
Interest cost	**106,669**	106,738	**19,617**	22,892
Plan participants' contributions	**-**	-	**8,047**	10,064
Plan amendments	**-**	-	**(74,313)**	(48)
Special termination benefits	**-**	1,435	**-**	-
Actuarial loss	**241,130**	112,123	**30,444**	5,725
Benefits paid	**(131,196)**	(137,566)	**(46,367)**	(44,732)
Federal subsidy on benefits paid	**-**	-	**1,511**	3,178
Nonutility subsidiaries sold in 2012	**(1,055)**	-	**(854)**	-
Benefit obligation at December 31	**$2,564,264**	$2,317,916	**$415,543**	$473,218
Change in plan assets				
Fair value of plan assets at January 1	**$2,046,793**	$2,151,199	**$108,574**	$147,998
Actual return on plan assets	**257,090**	3,583	**15,255**	(8,611)
Employer contributions	**24,180**	29,577	**41,320**	37,667
Plan participants' contributions	**-**	-	**8,047**	10,064
Benefits paid	**(131,196)**	(137,566)	**(46,367)**	(44,731)
Withdrawal from VEBA		-	**(8,380)**	(33,813)
Nonutility subsidiaries sold in 2012	**(294)**	-	**-**	-
Fair value of plan assets at December 31	**$2,196,573**	$2,046,793	**$118,449**	$108,574
Funded status at December 31	**$(367,691)**	$(271,123)	**$(297,094)**	$(364,644)

Amounts recognized in the balance sheet December 31,	**Pension Benefits 2012**	**2011**	**Postretirement Benefits 2012**	**2011**
(Thousands)				
Current liabilities	**-**	-	**$(7,377)**	$(6,995)
Noncurrent liabilities	**$(367,691)**	$(271,123)	**(289,717)**	(357,649)
	$(367,691)	$(271,123)	**$(297,094)**	$(364,644)

Effective January 1, 2013, for current and future nonunion Medicare-eligible retirees (typically age 65 and above) and certain current union retirees and their dependents, we transitioned from company-sponsored group coverage to individual coverage available on the open market. We communicated the changes to retirees and employees in early August 2012. Due to the change, as of September 1, 2012, we remeasured both the plan assets and benefit obligations of the various affected companies' OPEB plans, using current values and updated assumptions. The remeasured APBO and Net periodic benefit cost prospectively from the date of the event were based on a discount rate of 4.0%. The remeasurement reflected an updated discount rate, updated asset values and updated census information, as well as the effect of the change to the benefit plan, including a change in the participation rate.

Notes to Consolidated Financial Statements

In August 2011 RG&E offered a voluntary early retirement program (VERP) to qualifying union employees. The 27 employees who accepted the VERP will receive forms of enhanced pension benefits. In 2011 we recorded costs totaling approximately $1.4 million for the VERP, which will be paid from RG&E's pension plan.

We have determined that all of our operating companies are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities consist of:

	Pension Benefits		Postretirement Benefits	
December 31,	**2012**	**2011**	**2012**	**2011**
(Thousands)				
Net loss	**$1,068,794**	$1,023,676	**$77,037**	$61,869
Prior service cost (credit)	**$20,370**	$25,498	**$(79,463)**	$(13,882)
Transition obligation	**-**	-	**-**	$6,800

Our accumulated benefit obligation for all defined benefit pension plans was $2.4 billion at December 31, 2012, and $2.2 billion at December 31, 2011.

CMP's and NYSEG's postretirement benefits were partially funded at December 31, 2012 and 2011. NYSEG withdrew $8 million in 2012 and $33 million in 2011 from its postretirement benefit fund to pay for a portion of its postretirement costs.

The projected benefit obligation exceeded the fair value of pension plan assets for all plans as of December 31, 2012 and 2011. The accumulated benefit obligation exceeded the fair value of pension plan assets for all plans as of December 31, 2012; and for the CMP and RG&E plans as of December 31, 2011. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the companies' plans for the relevant periods.

	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets	
December 31,	**2012**	**2011**	**2012**	**2011**
(Thousands)				
Projected benefit obligation	**$2,564,264**	$2,317,916	**$2,564,264**	$807,066
Accumulated benefit obligation	**$2,387,496**	$2,170,784	**$2,387,496**	$744,509
Fair value of plan assets	**$2,196,573**	$2,046,793	**$2,196,573**	$618,140

Notes to Consolidated Financial Statements

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities:

	Pension Benefits		Postretirement Benefits	
Year ended December 31,	**2012**	**2011**	**2012**	**2011**
(Thousands)				
Net periodic benefit cost				
Service cost	**$30,800**	$28,766	**$4,240**	$4,727
Interest cost	**106,669**	106,738	**19,617**	22,892
Expected return on plan assets	**(170,891)**	(195,481)	**(5,939)**	(7,375)
Amortization of prior service cost (benefit)	**4,519**	4,802	**(8,731)**	(5,962)
Amortization of net loss	**109,597**	92,458	**6,110**	7,811
Special termination benefit charge	**-**	1,435	**-**	-
Amortization of transition obligation	**-**	-	**6,800**	6,800
Net periodic benefit cost	**$80,694**	$38,718	**$22,097**	$28,893
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss	**$154,931**	$304,021	**$21,129**	$21,711
Amortization of net (loss)	**(109,597)**	(92,457)	**(6,110)**	(7,811)
Current year prior service cost	**-**	-	**(74,314)**	(48)
Amortization of prior service (cost)	**(4,519)**	(4,802)	**8,731**	5,962
Amortization of transition obligation	**-**	-	**(6,800)**	(6,800)
Total recognized in regulatory assets and regulatory liabilities	**40,815**	206,761	**(57,364)**	13,014
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$121,509**	$245,479	**$(35,267)**	$41,907

We include the net periodic benefit cost in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents. We have amortized over 20 years the transition obligation for postretirement benefits that resulted from our adoption in 1992 of the accounting requirements concerning employers' accounting for postretirement benefits other than pensions.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2013	**Pension Benefits**	**Postretirement Benefits**
(Thousands)		
Estimated net loss	$120,407	$3,301
Estimated prior service cost	$4,279	$(14,441)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ended December 31, 2013.

Weighted-average assumptions used to	**Pension Benefits**		**Postretirement Benefits**	
determine benefit obligations at December 31,	**2012**	**2011**	**2012**	**2011**
Discount rate	**4.10%**	4.75%	**4.10%**	4.75%
Rate of compensation increase	**4.00%**	4.00%	**4.00%**	4.00%

As of December 31, 2012, we reduced our discount rate from 4.75% to 4.10%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade noncallable bonds with above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for year ended December 31,	Pension Benefits 2012	Pension Benefits 2011	Postretirement Benefits 2012	Postretirement Benefits 2011
Discount rate	**4.75%**	5.00%	**4.75%**	5.00%
Expected long-term return on plan assets	**7.75%**	8.75%	**-**	-
Expected long-term return on plan assets - nontaxable trust	**-**	-	**7.50%**	8.00%
Expected long-term return on plan assets - taxable trust	**-**	-	**4.75%**	4.80%
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. The operating companies amortize unrecognized actuarial gains and losses either over 10 years from the time they are incurred or using the standard amortization methodology, under which amounts in excess of 10% of the greater of the projected benefit obligation or market-related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates to determine benefit obligations at December 31,	2012	2011
Health care cost trend rate assumed for next year	**7.6%/7.5%**	7.8%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**4.5%**	4.5%
Year that the rate reaches the ultimate trend rate	**2028**	2028

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

(Thousands)	1% Increase	1% Decrease
Effect on total of service and interest cost	**$117**	**$(103)**
Effect on postretirement benefit obligation	**$2,387**	**$(2,188)**

Cash Flows

Contributions**:** In accordance with our funding policy we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $8 million to our pension benefit plans in 2013.

***Estimated future benefit payments*:** Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2013	$151,587	$37,170	$2,043
2014	$154,795	$33,132	$188
2015	$158,897	$32,479	$227
2016	$164,736	$31,860	$274
2017	$165,644	$31,514	$343
2018 - 2022	$837,739	$141,328	$3,075

***Plan assets*:** Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

Our asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets of 45% equity securities, 35% fixed income and 20% for all other types of investments. The target allocations within allowable ranges are further diversified into 20% large cap domestic equities, 5% medium and small cap domestic equities, 5% emerging markets, and 15% international equity securities. Fixed income investment targets and ranges are segregated into long dated corporate securities 10%, annuity contracts 8%, long-term treasury strips 5%, treasury inflation protection securities 5% and opportunistic fixed income 7%. All fixed income investments are in domestic securities. Other, alternative investment targets are 5% for real estate, and 15% for absolute return and strategic markets. Systematic rebalancing within the target ranges, should any asset categories drift outside their specified ranges, increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

The fair values of our pension benefits plan assets at December 31, 2012 and 2011, by asset category are:

Asset Category	Total	Fair Value Measurements at December 31, Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(Thousands)				
2012				
Cash and cash equivalents	**$78,161**	**$460**	**$77,701**	**-**
U.S. government securities	**224,377**	**224,377**	**-**	**-**
Common stocks	**690,621**	**523,352**	**167,269**	**-**
Registered investment companies	**180,961**	**180,961**	**-**	**-**
Corporate bonds	**258,170**	**-**	**258,170**	**-**
Preferred stocks	**3,702**	**3,702**	**-**	
Common/collective trusts	**306,704**	**-**	**57,154**	**$249,550**
Partnership/joint venture interests	**50,040**	**-**	**-**	**50,040**
Real estate investments	**59,119**	**-**	**-**	**59,119**
Other investments, principally annuity and fixed income	**344,718**	**22,739**	**2,942**	**319,037**
Total	**$2,196,573**	**$955,591**	**$563,236**	**$677,746**
2011				
Cash and cash equivalents	$59,220	-	$59,220	-
U.S. government securities	110,250	$110,250	-	-
Common stocks	864,801	614,330	250,471	-
Registered investment companies	108,340	108,340	-	-
Corporate bonds	277,432	137	277,295	-
Preferred stocks	2,945	2,945	-	
Common/collective trusts	320,898	-	56,885	$264,013
Partnership/joint venture interests	50,928	-	-	50,928
Real estate investments	52,298	-	-	52,298
Other investments, principally annuity and fixed income	199,681	22,421	1,743	175,517
Total	$2,046,793	$858,423	$645,614	$542,756

Valuation techniques: We value our pension benefits plan assets as follows:

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities, Common stocks and Registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common/collective trusts and Partnership/joint ventures – using the Net Asset Value (NAV) provided by the administrator of the fund. The NAV is based on the value of the underlying assets owned by the fund, minus its liabilities, and then divided by the number of shares outstanding. The NAV is classified as Level 2 if the plan has the ability to redeem the investment with the investee at NAV per share at the measurement date. Redemption restrictions or adjustments to NAV based on unobservable inputs result in the fair value measurement being classified as Level 3 if those inputs are significant to the overall fair value measurement.

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- Real estate investments – based on a discounted cash flow approach that includes the projected future rental receipts, expenses and residual values because the highest and best use of the real estate from a market participant view is as rental property.
- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)				
(Thousands)	**Common/ Collective Trusts**	**Partner-ship/ Joint Venture Interests**	**Real Estate Invest-ments**	**Other Invest-ments**	**Total**
Balance, December 31, 2010	$274,932	$96,624	$45,374	$190,312	$607,242
Actual return on plan assets:					
Relating to assets still held at the reporting date	(12,053)	(10,335)	3,832	(908)	(19,464)
Relating to assets sold during the year	2,377	8,052	-	2	10,431
Purchases, sales and settlements	(1,243)	-	3,092	(13,889)	(12,040)
Transfers into and/or out of Level 3	-	(43,413)	-	-	(43,413)
Balance, December 31, 2011	264,013	50,928	52,298	175,517	542,756
Actual return on plan assets:					
Relating to assets still held at the reporting date	**35,499**	**(1,830)**	**-**	**17**	**33,686**
Relating to assets sold during the year	**5,833**	**4,347**	**1,876**	**4,363**	**16,419**
Purchases, sales and settlements	**(55,795)**	**(3,405)**	**4,945**	**139,140**	**84,885**
Transfers into and/or out of Level 3	**-**	**-**	**-**	**-**	**-**
Balance, December 31, 2012	**$249,550**	**$50,040**	**$59,119**	**$319,037**	**$677,746**

Our postretirement benefits plan assets are held with a trustee in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes in order to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 26% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes. The remainder is invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for our postretirement benefits plan assets of 52% equity securities, 38% fixed income and 10% for all other types of investments. The target allocations within allowable ranges are further diversified into 20% large cap domestic equities, 14% medium and small cap domestic equities, 11% international developed market and 7% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 31%, global high yield fixed income 4% and international developed market debt 3%. Other, alternative investment targets are 5% for real estate and 5% absolute return. Systematic rebalancing within target ranges, should any asset categories drift outside their specified ranges, increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

The fair values of our other postretirement benefits plan assets at December 31, 2012 and 2011, by asset category are:

		Fair Value Measurements at December 31, Using		
Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(Thousands)				
2012				
Money market funds	**$4,586**	**$4,586**	**-**	**-**
Mutual funds, fixed	**46,443**	**46,443**	**-**	**-**
Mutual funds, equity	**61,617**	**61,617**	**-**	**-**
Mutual funds, other	**5,803**	**5,803**	**-**	**-**
Total assets measured at fair value	**$118,449**	**$118,449**	**-**	**-**
2011				
Money market funds	$2,858	$2,858	-	-
Mutual funds, fixed	43,614	43,614	-	-
Mutual funds, equity	57,895	57,895	-	-
Mutual funds, other	4,207	4,207	-	-
Total assets measured at fair value	$108,574	$108,574	-	-

Valuation techniques: We value our postretirement benefits plan assets as follows:

- Money market funds and Mutual funds, fixed and equity – based upon quoted market prices in active markets, which represent the NAV of the shares held.
- Other investments – these are primarily 401(h) investments that are an allocation of pension Master Trust investments.

Diversified equity securities did not include any Iberdrola common stock at December 31, 2012.

Note 15. NYSEG and RG&E Rate Proceedings

On September 16, 2010, the NYPSC approved a new rate plan for electric and natural gas service provided by the companies effective August 26, 2010, through December 31, 2013. Major provisions of the plan include:

- Approximate delivery rate increases as follows (in millions of dollars):

Rate year ending August 31,	NYSEG Electric	NYSEG Natural Gas	RG&E Electric	RG&E Natural Gas
2011	$16.4 (2.5%)	$9.9 (6.0%)	$15.6 (4.1%)	$10.9 (8.0%)
2012	$27.8 (4.2%)	$10.3 (5.8%)	$10.2 (2.6%)	$10.9 (7.3%)
2013	$29.3 (4.3%)	$10.5 (5.6%)	$13.2 (3.2%)	$11.0 (6.9%)

- The delivery rate increases were moderated and levelized through the use of $311 million in positive benefits adjustments (PBAs), including $36 million of carrying costs, that were required and set aside for the benefit of ratepayers when Iberdrola, S.A. acquired NYSEG and RG&E in 2008. The PBAs will be utilized as follows: in September 2010 a one-time write-off of

$82.5 million, which is offset by write-offs of deferred storm costs of $76.4 million, $6.1 million in property tax and amortizations during the rate years ended August 31 of: $88.0 million in 2011, $54.4 million in 2012 and $26.9 million in 2013; and $8.5 million in the four months ended December 31, 2013. The balance of $50.2 million will be amortized at a later time.

- Rates were set to allow for the recovery, over the 40 months of the rate plan, of regulatory assets of $126.0 million net of regulatory liabilities.
- The recovery includes $32.4 million for the cost to achieve efficiency initiatives through workforce reductions. The rate increases were moderated with $19.2 million in annual net savings from workforce reduction and related labor cost-cutting initiatives, as well as a one percent annual productivity adjustment.
- The revenue requirements are based on a 10% allowed ROE applied to an equity ratio of 48 percent. Beginning in 2011, if earnings exceed the allowed return, a tiered earnings sharing mechanism (ESM) will capture a portion of the excess for the benefit of ratepayers. The ESM is subject to specified downward adjustments if the companies fail to meet certain reliability and customer service measures.
- Key components of the rate plan include electric reliability performance mechanisms, natural gas safety performance measures, customer service quality metrics and targets, and electric distribution vegetation management programs that establish threshold performance targets. There will be downward revenue adjustments if the companies fail to meet the targets.
- Low-income program budgets have been increased to approximately $19.2 million. All home energy assistance program recipients will be eligible for the program.
- New revenue decoupling mechanisms (RDMs), intended to remove company disincentives to promote increased energy efficiency were established. Under the RDMs, electric revenues are based on revenue per customer class rather than billed revenue, while natural gas revenues are based on revenue per customer. Any shortfalls (excesses) between billed revenues and allowed revenues will be accrued for future recovery (refund).

In August 2010 NYSEG began amortizing $15.2 million per year of a theoretical excess depreciation reserve of $303.9 million; and on September 1, 2012, RG&E began amortizing $5.25 million per year of its theoretical excess depreciation reserve of $105 million. Both amortization amounts reflect a 20-year amortization period. Theoretical excess depreciation is the difference between actual accumulated depreciation taken to date and a theoretical reserve. The actual accumulated depreciation is the result of depreciation rates allowed in prior rate orders based on estimates of useful lives and net salvage values as determined in those cases. The theoretical reserve is the amount that would have accumulated if the depreciation rates in the new rate plan had been in place for the entire useful lives of the affected assets. Differences between the actual reserve and the theoretical reserve are normal aspects of utility ratemaking. The usual treatment is to flow any excess or deficiency back as an adjustment to depreciation expense over the remaining life of the property. However, in accordance with the new rate plan, NYSEG and RG&E will moderate electric rates by recording the theoretical reserve amortization as a debit to accumulated depreciation and a credit to other revenues, and normalize the amortization from a tax perspective.

Note 16. Sale of NYSEG's Seneca Lake Storage Facility

In January 2010 NYSEG entered into an agreement to sell its Seneca Lake Storage facility and related assets for $65 million. The sale was made contingent on receiving appropriate regulatory approvals from the NYPSC. The FERC issued an order in August 2010 authorizing the parties to proceed with the transaction, subject to compliance requirements that the buyer was required to attend to but that would not delay the closing. The NYPSC issued an order in March 2011 approving the transaction, but included several conditions in the order, which NYSEG met. The sale was completed in July 2011. In the third quarter of 2011 NYSEG recognized a gain of $32 million on the sale of which $20 million was recorded as a regulatory liability in compliance with the NYPSC order to return part of the gain to ratepayers and $12 million was recorded to other income. The regulatory liability is being amortized over a 40-month period through December 2014.

Note 17. Sale of Fossil Fuel Generation Assets

Iberdrola, in connection with receiving authorization from the NYPSC in September 2008 to acquire Energy East, agreed to sell certain fossil fuel generation assets owned by either RG&E or Cayuga Energy, Inc. (Cayuga). In its order authorizing the acquisition, the NYPSC directed Iberdrola and the other petitioners in the acquisition proceeding to develop, in collaboration with interested parties, a divestiture plan for the fossil fuel generation assets. Iberdrola and Energy East filed the divestiture plan with the NYPSC in November 2008. The NYPSC issued an order approving the divestiture plan as filed, effective in November 2009.

The divestiture plan required the generation assets to be sold at auction in a two-stage process, as well as extensive consultation with the NYPSC Staff concerning the auction process. The auction process would be suspended, but not terminated, if bids obtained were priced at less than the current net book value of the assets (approximately $14 million at December 31, 2009). We would then petition the NYPSC for guidance on the next steps to be taken.

We submitted a modified auction plan to the NYPSC in October 2011 on behalf of RG&E and Cayuga, which the NYPSC adopted in its order issued and effective in December 2011. The modified plan provides for the bundling of the Allegany and Carthage generating stations as two components of one package, although separate bids will be accepted, and the other assets as a second package. Although we are to seek NYPSC guidance if the best bid for Allegany, which is owned by RG&E, would result in a loss, the same is not true for Carthage, which is owned by Cayuga. RG&E will compare the auction results to the value that could be obtained through self-salvage before the disposition of the assets in the second package is determined. As result of the December 2011 order we performed an impairment test on the Carthage assets and recorded an impairment of $2.7 million in 2011. On December 17, 2012, we received two bids in connection with the sale of the fossil fuel generation assets. Management determined it was appropriate to write down the value of the Carthage assets to the amount of the best bid of $1.1 million, resulting in a pretax impairment loss of $3.4 million. (See Note 12.)

Management expects to complete the auction process and sale of assets within one year and we have determined that the criteria are now met in order to classify the assets as held for sale. We have ceased depreciation of the remaining value of the Carthage assets, as is proper for assets classified as held for sale. We have not recorded an impairment loss for RG&E's assets, and have not ceased depreciation of Allegany because its cost is being recovered in rates.

Note 18. CMP Rate Setting Process

CMP's rates are segregated into three primary components: transmission, distribution and stranded costs, each governed by a distinct regulatory process. The transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, as well as return of and on investment in transmission assets. The base ROE is currently set at 11.14% with various additional return adders applicable to assets based upon vintage, voltage, and other factors. The formula also includes provisions to reflect forecasted plant additions in rates, subject to reconciliation in the following year. Pursuant to a FERC incentive rate order, CMP is also allowed to include the CWIP related to the MPRP in rates, subject to the same reconciliation mechanism.

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Pursuant to CMP's FERC authorized transmission rate formula, annual rate updates include an annual true-up (ATU) adjustment. The ATU is a reconciliation adjustment designed to recognize the rate impact of differences between the forecast levels of transmission plant additions and CWIP assumed for inclusion in rates, and the actual values for those rate components realized during the rate effective period. During 2012 CMP submitted to the FERC a change in CMP's rate formula that clarifies the implementation of FERC's authorized CWIP incentive for CMP's MPRP and, specifically, the timing of CMP's CWIP related recovery. Primarily as a result of the CWIP formula change, accepted by the FERC in May 2012, an ATU adjustment of $40.5 million was incorporated in CMP's rate update as a reduction in rates effective June 1, 2012. Consistent with its historical practice, CMP recognized the full $40.5 million ATU refund obligation as a regulatory liability in June 2012 and will amortize the liability over the subsequent 12 months of the effective rate year as the revenue reduction is realized.

CMP's distribution service rates are established pursuant to ARP 2008 approved by the MPUC with a five-year term that commenced on January 1, 2009. Under ARP 2008, our distribution service prices are adjusted on July 1 each year based on an inflation index minus a 1% productivity factor. The rate plan also includes annual price change provisions for the recovery of significant unanticipated costs, including costs arising from changes in law, capital gains or losses, environmental remediation and major storms. CMP's operational performance is measured annually under the plan by seven service quality indicators and it is subject to penalties of up to $5 million for failure to achieve targeted levels of performance.

CMP recovers “stranded costs” pursuant to annual price adjustments that are also regulated by the MPUC. Those costs primarily include above-market costs of electric capacity and energy purchased under long-term power purchase agreements, as well as costs associated with CMP's interests in four decommissioned nuclear generation facilities. Stranded costs rates are periodically established based upon forecasts and are then fully reconciled to actual costs and recovery amounts on an annual basis.

On March 14, 2012, CMP submitted its request for the fourth annual price change under its distribution service ARP 2008. The request seeks an increase in CMP's distribution prices of approximately $12.3 million, effective July 1, 2012. The increase reflects an inflation index value of 2.12 percent, less a one percent productivity factor, the elimination of various items recovered over the prior rate year, the inclusion of approximately $15.7 million relating to a one-year recovery of 2011 storm restoration costs and several other minor items. On June 21, 2012, the MPUC approved a stipulation resolving all matters relating to the July 1, 2012, annual price change. The stipulation incorporates numerous minor revisions to price change formula inputs and amortizes 2011 storm restoration costs over a two-year period, resulting in a net distribution price increase of $4.5 million, or 2.15 percent.