UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________to __________

Commission file number 000-50039

OLD DOMINION ELECTRIC COOPERATIVE
(Exact name of Registrant as specified in its charter)

VIRGINIA	**23-7048405**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. employer identification no.)**
4201 Dominion Boulevard, Glen Allen, Virginia	**23060**
(Address of principal executive offices)	**(Zip code)**

(804) 747-0592
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act: NONE

Securities registered pursuant to Section 12(g) of the Act:

6.25% 2001 Series A Bonds due 2011

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act?
Yes ☐ No ☒
Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☒
Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 of 15(d) of the Exchange Act from their obligations under those Sections.

Indicate by check mark whether the Registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this form 10-K. ☐

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☒	Smaller reporting company

Indicate by check mark whether the Registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant. NONE

Indicate the number of shares outstanding of each of the Registrant's classes of Common Stock, as of the latest practicable date. The Registrant is a membership corporation and has no authorized or outstanding equity securities.

Documents incorporated by reference: NONE

OLD DOMINION ELECTRIC COOPERATIVE

2009 ANNUAL REPORT ON FORM 10-K

PART I

ITEM 1. BUSINESS

General

Old Dominion Electric Cooperative ("ODEC" or "we" or "our") was incorporated under the laws of the Commonwealth of Virginia in 1948 as a not-for-profit power supply cooperative. We are organized for the purpose of supplying the power our member distribution cooperatives require to serve their customers on a cost-effective basis. We serve their power requirements pursuant to long-term, all-requirements wholesale power contracts. Through our member distribution cooperatives, we served more than 445,000 retail electric consumers (meters), representing a total population of approximately 1.0 million people in 2009.

We supply our member distribution cooperatives' power requirements, consisting of capacity requirements and energy requirements, through a portfolio of resources including generating facilities, power purchase contracts, and forward, short-term and spot market energy purchases. Our generating facilities are fueled by a mix of coal, nuclear, natural gas, and fuel oil. See "—Power Supply Resources" below and "Properties" in Item 2 for a description of these resources.

We are owned entirely by our members, which are the primary purchasers of the power we sell. We have two classes of members. Our Class A members are customer-owned electric distribution cooperatives that are engaged in the retail sale of power to their member-consumers. Our sole Class B member is TEC Trading, Inc. ("TEC"), a taxable corporation owned by our member distribution cooperatives. Our member distribution cooperatives primarily serve suburban, rural and recreational areas. These areas predominantly reflect stable growth in residential capacity and energy requirements both in terms of power sales and number of customers. See "—Members' Service Territories and Customers" below.

As a not-for-profit electric cooperative, we are currently exempt from federal income taxation under Section 501(c)(12) of the Internal Revenue Code of 1986, as amended.

We are not a party to any collective bargaining agreement. We had 107 employees as of March 3, 2010.

Our principal executive offices are located in the Innsbrook Corporate Center, at 4201 Dominion Boulevard, Glen Allen, Virginia 23060-6721. Our telephone number is (804) 747-0592.

Cooperative Structure

We are a power supply cooperative. In general, a cooperative is a business organization owned by its members, which are also either the cooperative's wholesale or retail customers. Cooperatives are designed to give their members the opportunity to satisfy their collective needs in a particular area of business more effectively than if the members acted independently. As not-for-profit organizations, cooperatives are intended to provide services to their members on a cost-effective basis, in part by eliminating the need to produce profits or a return on equity in excess of required margins. Margins not distributed to members constitute patronage capital, a cooperative's principal source of equity. Patronage capital is held for the account of the members without interest and returned when the board of directors of the cooperative deems it appropriate to do so.

Electric distribution cooperatives form power supply cooperatives to acquire power supply resources, typically through the construction of generating facilities or the development of other power purchase arrangements, at a lower cost than if they were acquiring those resources alone.

Our Class A members are electric distribution cooperatives. Electric distribution cooperatives own and maintain nearly half of the distribution lines in the United States and serve three-quarters of the United States' land mass. There are currently approximately 870 electric distribution cooperatives in the United States. Electric distribution cooperatives own and operate electric distribution systems to supply the power requirements of their retail customers.

Member Distribution Cooperatives

General

Our member distribution cooperatives provide electric services, consisting of power supply, transmission services, and distribution services (including metering and billing) to residential, commercial, and industrial customers. We have eleven member distribution cooperatives that serve customers in 65 counties in Virginia, Delaware, Maryland, and a small portion of West Virginia. The member distribution cooperatives' distribution business involves the operation of substations, transformers, and electric lines that deliver power to customers.

Three of our member distribution cooperatives provide electric services on the Delmarva Peninsula:

A&N Electric Cooperative in Virginia
Choptank Electric Cooperative, Inc. in Maryland
Delaware Electric Cooperative, Inc. in Delaware

Eight of our member distribution cooperatives provide electric services on the Virginia mainland:

BARC Electric Cooperative
Community Electric Cooperative
Mecklenburg Electric Cooperative
Northern Neck Electric Cooperative
Prince George Electric Cooperative
Rappahannock Electric Cooperative
Shenandoah Valley Electric Cooperative[1]
Southside Electric Cooperative

[1]Also serves a small portion of West Virginia

The member distribution cooperatives are not our subsidiaries, but rather our owners. We have no interest in their properties, liabilities, equity, revenues, or margins. See "Wholesale Power Contracts" and "Proposed Acquisition of Additional Service Territory" below.

Revenues from our member distribution cooperatives and the percentage each contributed to total member distribution cooperative revenues in 2009 are as follows:

Member Distribution Cooperatives	**Revenues** (in millions)	**Total Revenues** (%)
Rappahannock Electric Cooperative	$191.4	28.2%
Delaware Electric Cooperative, Inc.	101.5	15.0
Choptank Electric Cooperative, Inc.	80.2	11.8
Southside Electric Cooperative	70.6	10.4
Shenandoah Valley Electric Cooperative	64.5	9.5
A&N Electric Cooperative	53.3	7.8
Mecklenburg Electric Cooperative	43.4	6.4
Prince George Electric Cooperative	23.7	3.5
Northern Neck Electric Cooperative	21.7	3.2
Community Electric Cooperative	15.8	2.3
BARC Electric Cooperative	13.0	1.9
Total	$679.1	100.0%

Wholesale Power Contracts

Our financial relationships with our member distribution cooperatives are based primarily on our contractual arrangements for the supply of power and related transmission and ancillary services. These arrangements are set forth in our wholesale power contracts with our member distribution cooperatives which are effective until January 1, 2054 and beyond this date unless either party gives the other at least three years notice of termination. The wholesale power contracts are "all-requirements" contracts. Each contract obligates us to sell and deliver to the member distribution cooperative, and obligates the member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions, to the extent that we have the power and facilities available to do so.

The two principal exceptions to the all-requirements obligations of the member distribution cooperatives relate to the ability of our mainland Virginia member distribution cooperatives to purchase hydroelectric power allocated to them from the Southeastern Power Administration ("SEPA"), and the ability of all member distribution cooperatives to purchase energy from specified qualifying facilities under the Public Utility Regulatory Policies Act ("PURPA") or similar laws. Purchases under these exceptions constituted less than 3.0% of our member distribution cooperatives' total capacity and energy requirements in 2009.

Two additional limited exceptions to the all-requirements nature of the contract permit the member distribution cooperatives to receive up to the greater of five percent of their power requirements or five megawatts from owned generation or other suppliers and to purchase additional power from other suppliers in limited circumstances following approval by our board of directors. Currently, none of our member distribution cooperatives have received any of their power requirements under these exceptions.

Each member distribution cooperative is required to pay us monthly for power furnished under its wholesale power contract in accordance with our formulary rate. The formulary rate, which has been filed with and accepted by the Federal Energy Regulatory Commission ("FERC"), is designed to recover our total cost of service and create a firm equity base. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Formulary Rate" in Item 7. More specifically, the formulary rate is intended to meet all of our costs, expenses and financial obligations associated with our ownership, operation, maintenance, repair, replacement, improvement, modification, retirement and decommissioning of our generating plants, transmission system or related facilities, services provided to the member distribution cooperatives, and the acquisition and transmission of power or related services, including:

- payments of principal and premium, if any, and interest on all indebtedness issued by us (other than payments resulting from the acceleration of the maturity of the indebtedness);
- any additional cost or expense, imposed or permitted by any regulatory agency; and
- additional amounts required to meet the requirement of any rate covenant with respect to coverage of principal and interest on our indebtedness contained in any indenture or contract with holders of our indebtedness.

The rates established under the wholesale power contracts are designed to enable us to comply with financing, regulatory and governmental requirements, which apply to us from time to time.

TEC

TEC is owned by our member distribution cooperatives, and currently is our only Class B member. We have a power sales contract with TEC, under which TEC purchases power from us that we do not need to meet the actual needs of our member distribution cooperatives and sells this power to the market under market-based rate authority granted by FERC. TEC also acquires natural gas and forward purchase contracts to hedge the price of natural gas to supply our combustion turbine facilities, and takes advantage of other power-related trading opportunities in the market which may help lower our member distribution cooperatives' costs. TEC does not engage in speculative trading. To facilitate TEC's participation in the power related markets, we have agreed to provide a maximum of $100.0 million in credit support to TEC. See "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations—Significant Contingent Obligations—TEC Guarantees."

Members' Service Territories and Customers

Delaware and Maryland each currently grant all retail customers the right to choose their power supplier. Virginia currently grants only a limited number of very large retail customers the right to choose their power suppliers and only in very limited circumstances. The laws of each state grant utilities, including our member distribution cooperatives, the exclusive right to provide transmission and distribution (including metering and billing) services and to be the default providers of power to their customers in service territories certified by their respective state public service commissions. See "—Regulation—Competition" below.

The territories served by our member distribution cooperatives cover large portions of Virginia, Delaware, and Maryland. One of our member distribution cooperatives also serves a small portion of West Virginia. These service territories range from the extended suburbs of Washington D.C. to the Atlantic shores of Virginia, Delaware and Maryland to the Appalachian Mountains and the North Carolina border. In 2009, the service territories of member distribution cooperatives serving the high growth, increasingly suburban area between Washington, D.C. and Richmond, Virginia accounted for approximately a quarter of our capacity requirements. While our member distribution cooperatives do not serve any major cities, several portions of their service territories are in close proximity to urban areas. These areas continue to experience modest growth due to the expansion of suburban communities into neighboring rural areas and the continuing development of resort and vacation communities within their service territories; however recent economic trends could affect the level of growth. Additionally, our member distribution cooperatives can expand their service territories through acquisition. See "Proposed Acquisition of Additional Service Territory" below.

Our member distribution cooperatives' service territories are diverse and encompass primarily suburban, rural and recreational areas. These customers' requirements for capacity and energy generally are seasonal and increase in winter and summer as home heating and cooling needs increase and then decline in the spring and fall as the weather becomes milder. Our member distribution cooperatives also serve major industries which include manufacturing, telecommunications, poultry, fisheries, agriculture, forestry and wood products, paper, travel, and trade.

Our member distribution cooperatives' sales of energy in 2009 totaled approximately 8,349,656 mega-watt hours ("MWh"). These sales were divided by type as follows:

Customer Class	Percentage of MWh Sales	Percentage of Customers
Residential	66.1%	90.9%
Commercial and industrial	32.2	8.0
Other	1.7	1.1

From 2004 through 2009, our eleven member distribution cooperatives experienced an average annual compound growth rate of approximately 3.4% in the number of customers and an average annual compound growth rate of 2.6% in energy sales measured in MWh.

Our eleven member distribution cooperatives' average number of customers per mile of energized line has increased approximately 7.0% since 2004 to approximately 8.5 customers per mile in 2009. System densities of our member distribution cooperatives in 2009 ranged from 6.2 customers per mile in the service territory of BARC Electric Cooperative to 14.5 customers per mile in the service territory of A&N. In 2009, the average service density for all distribution electric cooperatives in the United States was approximately 7.0 customers per mile.

Proposed Acquisition of Additional Service Territory

In 2009, two of our member distribution cooperatives, Rappahannock Electric Cooperative ("REC") and Shenandoah Valley Electric Cooperative ("SVEC"), entered into separate asset purchase agreements to severally acquire the distribution assets and right to provide electric distribution services to approximately 102,000 customers (meters) of The Potomac Edison Company in Virginia ("Potomac Edison").

In accordance with the wholesale power contracts between ODEC and its member distribution cooperatives, ODEC anticipates that it will serve the additional power requirements related to REC's and SVEC's acquisition. As part of the acquisition transaction we will not purchase any assets; however, we will assume full requirements power supply contracts previously entered into by Potomac Edison for the service territory. These contracts have differing terms and the latest date any of these contracts expires in June 30, 2011.

We currently anticipate that REC's and SVEC's acquisition, including the assumption of the power supply contracts from Potomac Edison, will result in lowering our average cost of power to all of our member distribution cooperatives. As a result, in accordance with our load acquisition policy, we will pay a transition fee to REC and to SVEC that represents a portion of the projected power cost savings related to these acquisitions. The aggregate transition fee is estimated to be approximately $66.7 million. Upon closing of the acquisitions, the transition fee will be reflected as a credit on the monthly power invoices of REC and SVEC over a four year period. The transition fee will be collected from our member distribution cooperatives through our formulary rate.

Consummation of the acquisitions by REC and SVEC is subject to the satisfaction of several conditions including obtaining all necessary regulatory approvals. The Virginia State Corporation Commission ("VSCC") held a hearing that began on March 2, 2010. Although we anticipate that the acquisition will close in 2010, we cannot predict when, or even if, all of the conditions to the closing of the acquisition will be satisfied and whether the closing will occur.

New Dominion

In 2004, we entered into a reorganization agreement with our member distribution cooperatives, TEC and a newly formed taxable power supply cooperative, New Dominion Energy Cooperative ("New Dominion"). Structurally, the reorganization would result in all of our member distribution cooperatives exchanging their membership interests in ODEC for a membership interest in New Dominion. We received regulatory approval for the reorganization contemplated by the reorganization agreement in 2008. We have evaluated whether the reorganization previously contemplated is in our best interests and the best interests of our member distribution cooperatives based on current conditions. Based on our current evaluation, we have decided not to actively pursue implementation of the reorganization at this time. As conditions change, we may reconsider this decision.

POWER SUPPLY RESOURCES

General

We provide power to our members through a combination of our interests in the Clover Power Station ("Clover"), North Anna Nuclear Power Station ("North Anna"), Louisa generating facility ("Louisa"), Marsh Run generating facility ("Marsh Run"), Rock Springs generating facility ("Rock Springs"), distributed generation facilities, physically-delivered forward power purchase contracts and spot purchases of power in the open market. Our power supply resources for the past three years have been as follows:

	Year Ended December 31,					
	2009		2008		2007	
Generated:			(in MWh and percentages)			
Clover	2,787,184	28.4%	2,901,401	21.5%	3,335,633	23.7%
North Anna	1,763,502	18.0	1,674,278	12.4	1,622,484	11.5
Louisa	93,125	0.9	153,170	1.1	234,701	1.7
Marsh Run	99,842	1.0	152,258	1.1	284,330	2.0
Rock Springs	29,906	0.3	55,045	0.4	56,117	0.4
Distributed Generation	457	-	286	-	668	-
Total Generated	4,774,016	48.6	4,936,438	36.5	5,533,933	39.3
Purchased:						
Total Purchased	5,041,201	51.4	8,580,110	63.5	8,542,152	60.7
Total Available Energy	9,815,217	100.0%	13,516,548	100.0%	14,076,085	100.0%

In 2009, our member distribution cooperatives' peak demand occurred in January and was 2,120 megawatts ("MW"), excluding power supplied by SEPA which is not an ODEC resource. See "—Wholesale Power Contracts". We anticipate that our member distribution cooperatives' peak demand will continue to occur during the winter due to the consumption patterns of the customers served by our member distribution cooperatives.

Clover and North Anna, our baseload generating facilities, satisfied approximately 32.9% of our capacity obligations and 46.4% of our energy requirements in 2009. Louisa, Marsh Run and Rock Springs, our peaking generating facilities, collectively provided 61.5% of our 2009 capacity obligations, and 2.2% of our 2009 energy requirements. For a description of our generating facilities, see "Properties" in Item 2. In 2009, we obtained the remainder of our capacity obligations through the PJM Interconnection, LLC ("PJM") reliability pricing model ("RPM") capacity auction process. See "—PJM" below. The energy requirements not met by our owned generation facilities were obtained from various suppliers under various long-term and short-term physically-delivered forward power purchase contracts and spot market purchases. See "—Power Purchase Contracts" below.

We plan to continue purchasing energy for significant periods into the future by utilizing a combination of physically-delivered forward power purchase contracts for the purchase of energy, as well as spot market purchases. As we have done in the past, we expect to adjust our portfolio of power supply resources to reflect our projected power requirements and changes in the market. To assist us in these efforts, we continue to engage ACES Power Marketing LLC ("APM"), an energy trading and risk management company. Specifically, APM assists us in negotiating power purchase contracts, evaluating the credit risk of counterparties, modeling our power requirements, bidding and dispatch of our combustion turbine facilities, and executing energy transactions. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

Power Supply Planning

We are continuing to evaluate participation in the ownership of an 11.6% undivided interest in an additional nuclear-powered generating unit at North Anna. In 2007, we filed a joint application with Virginia Electric and Power Company ("Virginia Power") at the Nuclear Regulatory Commission ("NRC") for a license to construct and operate a new reactor at North Anna. We expect the application review to take at least three years. We will continue to further evaluate the project and make a final determination as to our future involvement.

In addition, we are still in the process of separately evaluating the possibility of constructing a new base-load generation facility. We have secured options on two tracts of land in Virginia; one tract is in the town of Dendron in Surry County and the other is in Sussex County. In 2008, we selected the land in Surry County as the preferred site for the development of a base load power generation facility. In February 2010, we received the necessary zoning approvals for siting of a power plant and approval to proceed with the attainment of required air and other environmental permits. On March 2, 2010, several residents of Surry County filed a Complaint for Declaratory and Injunctive Relief with the Surry County Circuit Court, requesting that the court void the zoning approvals granted based on their claim of inadequate notice of a public hearing.

We anticipate that the power station would be fueled by a mixture of coal and biomass, a form of renewable energy. We have not selected the technology, the final site or determined the size of any facility that may be built. We have not made final commitments to proceed with the construction of a facility. See "—Regulation—Environmental—Proposed Construction of Generation Facility".

As part of our on-going power supply planning process, we issued a Request for Power Supply Proposals ("RFP") in June of 2009. In October 2009, we signed a long-term power purchase and sale agreement with Exelon Generation ("Exelon") in connection with our RFP process. Under the terms of this agreement, Exelon will begin supplying 200 MW of energy and capacity to us for ten years beginning in June 2010. We are continuing to evaluate additional proposals received as part of the RFP process.

PJM

PJM is a regional transmission organization ("RTO") that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. As a federally regulated RTO, PJM must act independently and impartially in managing the regional transmission system and the wholesale electricity market. PJM ensures the reliability of the largest centrally dispatched grid in North America. PJM coordinates the continuous buying, selling and delivery of wholesale electricity over its service territory. PJM system operators continuously conduct dispatch operations and monitor the status of the grid. PJM also oversees a regional planning process for transmission expansion to ensure the continued reliability of the electric system.

PJM serves all of Delaware, Maryland, West Virginia and most of Virginia, as well as other areas outside our member distribution cooperatives' service territories. We are a member of PJM and are therefore subject to the operations of PJM. PJM also coordinates and establishes policies for the generation, purchase and sale of capacity and energy in the control areas of its members, including all of the service territories of our member distribution cooperatives. As a result, our generating facilities are under dispatch control of PJM.

We transmit power to our member distribution cooperatives through the transmission systems of PJM–South Region, PJM–West Region, and PJM–East Region. We have agreements with PJM, which provide us with access to transmission facilities under their control as necessary to deliver energy to our member distribution cooperatives. We own a limited amount of transmission facilities. See "Properties—Transmission" in Item 2.

PJM continually balances its participants' power requirements with the power resources available to supply those requirements. Based on this evaluation of supply and demand, PJM schedules available generation facilities in a manner intended to meet the demand for energy in the most reliable and cost-effective manner. Thus, PJM directs the dispatch of these facilities even though it does not own them. When PJM cannot dispatch available generating facilities due to transmission constraints, PJM will dispatch more expensive generating facilities to meet the required power requirements. PJM participants whose power requirements cause the redispatch are obligated to pay the additional costs to dispatch the more expensive generating facilities. These additional costs are commonly referred to as congestion costs. PJM conducts the auction of financial transmission rights for future periods to provide market participants an opportunity to hedge these congestion costs.

The PJM energy market consists of day-ahead and real-time markets. PJM's day-ahead market is a forward market in which hourly locational marginal prices are calculated for the following day based on the prices at which the owners of generating facilities, including ODEC, offer to run their facilities and the requirements of energy consumers. PJM's real-time market is a spot market in which current locational marginal prices are calculated at five-minute intervals.

PJM rules require that load serving entities meet certain minimum generating capacity obligations. Additional capacity must be purchased for capacity obligations that are not met by an entity's owned generation resources. Participants can procure capacity through self-supply, bilateral agreements or forward capacity auctions under PJM's Reliability Pricing Model ("RPM"). In 2007, PJM implemented RPM in response to concerns that there was insufficient new investment in generation facilities. The purpose of RPM is to develop a longer-term pricing program for capacity resources, as well as provide localized pricing for capacity, and to reduce capacity price volatility and the resulting investment risk to generators thus encouraging new investment in generation facilities. The value of capacity resources varies by location and RPM provides for the recognition of the locational value. To date, PJM has conducted RPM auctions for capacity to be supplied through May 31, 2013. The next annual auction is scheduled to be held in May of this year for capacity to be supplied from June 1, 2013 to May 31, 2014. Thereafter, each annual auction will be held 36 months before each subsequent delivery year, and up to three incremental auctions may be held at prescribed dates after the base residual auction for each delivery year to adjust for capacity market dynamics.

Power Purchase Contracts

Our purchased power is provided principally by neighboring utilities and power marketers through physically-delivered power purchase contracts and purchases of energy in the spot markets.

We purchase significant amounts of power in the market through long-term and short-term physically-delivered forward power purchase contracts. We also purchase power in the spot market. This approach to meeting our member distribution cooperatives' energy requirements is not without risks. See "Risk Factors" in Item 1A. below. To mitigate these risks, we attempt to match our energy purchases with our energy needs to reduce our spot market purchases of energy. Additionally, we utilize policies and procedures to manage the risks in the changing business environment. These policies and procedures, developed in cooperation with APM, are designed to strike an appropriate balance between minimizing costs and reducing energy cost volatility.

We have contractual arrangements with Virginia Power, the operator and co-owner of Clover and North Anna, which permit us to purchase reserve capacity and energy. We intend to purchase our reserve capacity requirements for Clover and North Anna from Virginia Power under these arrangements until the date on which all facilities at North Anna have been retired or decommissioned, or the date we have no interest in North Anna, whichever is earlier.

Renewable Energy

Our power supply resources include renewable energy resources. We have a contract to purchase 50 MW of power and renewable energy credits from a wind project in north central Pennsylvania that will serve the territory of our member distribution cooperatives. This wind project became operational in 2009 and we began receiving output in December of 2009. We have also entered into a long-term agreement for wind generated power under which we will purchase power and renewable energy credits from a 70 MW wind energy facility currently under development in Western Maryland. The project is scheduled to be completed in late 2010. Additionally, we have renewable resources through energy purchase contracts from a landfill gas-to-energy project located in Worchester County, Maryland and a hydroelectric facility located in Alleghany County, Virginia.

Fuel Supply

Coal

Virginia Power, as operating agent of Clover, has the sole authority and responsibility to procure sufficient coal for the operation of the facility. Virginia Power advises us they use both long-term contracts and short-term spot agreements to acquire the low sulfur bituminous coal used to fuel the facility. We are not a direct party to any of these procurement contracts, and do not control their terms or duration. As of December 31, 2009, and December 31, 2008, there was a 92.0 day and a 54.0 day supply of coal at Clover, respectively. We anticipate that sufficient supplies of coal will be available in the future. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

Nuclear

Virginia Power, as operating agent of North Anna, has the sole authority and responsibility to procure nuclear fuel for the facility. Virginia Power advises us they primarily use long-term contracts to support North Anna's nuclear fuel requirements and that worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices which are dependent upon the market environment. We are not a direct party to any of these procurement contracts, and do not control their terms or duration. Virginia Power advises us that current agreements, inventories, and spot market availability are expected to support North Anna's current and planned fuel supply needs for the near term and that additional fuel is purchased as required to attempt to ensure optimal cost and inventory levels.

Natural Gas

Our three combustion turbine facilities are powered by natural gas and are located adjacent to natural gas transmission lines. With assistance from APM, we developed and utilize a natural gas supply strategy for providing natural gas to each of the three combustion turbine facilities. We are responsible for procuring the natural gas to be used by all of our units at Louisa, Marsh Run and Rock Springs. The strategy includes securing transportation contracts and incorporating the ability to use No. 2 distillate fuel oil as a back up fuel for Louisa and Marsh Run, as needed, to minimize natural gas pipeline transportation costs. We have identified our primary natural gas suppliers and have negotiated the contracts needed for procurement of physical natural gas. We have put in place strategies and mechanisms to financially hedge our natural gas needs. We anticipate that sufficient supplies of natural gas will be available in the future to support the operation of the combustion turbine facilities but significant price volatility may occur. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

REGULATION

General

We are subject to regulation by FERC and to a limited extent, state public service commissions. Some of our operations are also subject to regulation by the Virginia Department of Environmental Quality ("DEQ"), the Maryland Department of the Environment, the Department of Energy ("DOE"), the NRC, and other federal, state, and local authorities. Compliance with future laws or regulations may increase our operating and capital costs by requiring, among other things, changes in the design or operation of our generating facilities.

Rate Regulation

We establish our rates for power furnished to our member distribution cooperatives pursuant to our formulary rate, which has been accepted by FERC. The formulary rate is intended to permit us to collect revenues, which, together with revenues from all other sources, are equal to all of our costs and expenses, plus an additional amount up to 20% of our total interest charges, plus additional equity contributions as approved by our board of directors. The formula has three main components: a demand rate, a base energy rate, and a fuel factor adjustment rate. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results – Formulary Rate" in Item 7.

FERC may review our rates upon its own initiative or upon complaint and order a reduction of any rates determined to be unjust, unreasonable, or otherwise unlawful and order a refund for amounts collected during such proceedings in excess of the just, reasonable, and lawful rates. Our charges to TEC are established under our market-based sales tariff filed with FERC.

Because our rates and services are regulated by FERC, the VSCC, the Delaware Public Service Commission, and the Maryland Public Service Commission ("Maryland PSC") do not have jurisdiction over our rates and services. The state commissions, however, do oversee the siting of our utility facilities in their respective jurisdictions. The VSCC and Maryland PSC also regulate the rates and services offered by our Virginia and Maryland member distribution cooperatives, respectively.

Other FERC Regulation

In addition to its jurisdiction over rates, FERC regulates the issuance of securities and assumption of liabilities by us, as well as mergers, consolidations, the acquisition of securities of other utilities, and the disposition of property other than generating facilities. Under FERC regulations, we are prohibited from selling, leasing, or otherwise disposing of the whole of our facilities subject to FERC jurisdiction (other than generating facilities), or any part of such facilities having a value in excess of $10.0 million without FERC approval.

Competition

Delaware and Maryland each have laws unbundling the power component (also known as generation) of electric service to retail customers, while maintaining regulation of transmission and distribution services. All retail customers in Delaware and Maryland, including retail customers of our member distribution cooperatives located in those states, are currently permitted to purchase power from the registered supplier of their choice. In Virginia, certain large retail customers have very limited rights to choose their energy suppliers. At March 1, 2010, no entity had registered to be an alternative power supplier in any of the service territories of our member distribution cooperatives and, as a result, none of their retail customers have switched to alternative providers.

In Virginia, retail choice in the selection of a power supplier is only available to customers that consume at least five megawatts of power individually or in the aggregate (with aggregation subject to the approval of the VSCC), but that do not account for more than 1% of the incumbent utility's peak load during the past year. Also, retail choice is available for customers that desire to select a supplier that provides 100% green or renewable power and for any cooperative customer whose 2006, or any subsequent year's, noncoincident peak demand exceeded 90 megawatts. Currently, we do not anticipate that these conditions related to retail choice will have a material impact on our financial results. Also, beginning January 1, 2009, this legislation allowed our Virginia member distribution cooperatives to adjust their distribution rates by a maximum net increase or decrease of 5%, on a cumulative basis, in any three year period without filing a rate case with the VSCC. This legislation does not affect our Virginia member distribution cooperatives' ability to pass through changes in wholesale power costs to their customers.

Environmental

We are subject to federal, state, and local laws and regulations and permits designed to both protect human health and the environment and to regulate the emission, discharge, or release of pollutants into the environment. We believe we are in material compliance with all current requirements of such environmental laws and regulations and permits. However, as with all electric utilities, the operation of our generating units could be affected by future environmental regulations. Capital expenditures and increased operating costs required to comply with any future regulations could be significant. See "Risk Factors" in Item 1A. below. Our direct capital expenditures for environmental control equipment at our generating facilities, however, were immaterial in 2009.

Clean Air Act

The most pertinent environmental law affecting our operations is the Clean Air Act. The Clean Air Act requires, among other things, that owners and operators of fossil fuel-fired power stations limit emissions of sulfur dioxide ("SO_2"), particulate matter ("PM"), mercury (Hg), and nitrogen oxides ("NO_x"). Additionally, regulatory programs and/or taxes are being proposed to limit emissions of carbon dioxide ("CO_2") and other greenhouse gases.

The Clean Air Interstate Rule ("CAIR") requires significant reductions of SO_2 and NO_x in the eastern United States, including Virginia and Maryland. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAIR and later remanded CAIR for correction instead. The court did not set a deadline for the Environmental Protection Agency ("EPA") to make the corrections. CAIR in its existing form remains in effect until EPA promulgates the corrected rule.

The DEQ adopted the CAIR implementation regulations in 2007. Virginia participates in the federal SO_2 cap and trade program established by CAIR for SO_2 emissions. This program is similar, but is in addition to the Acid Rain Program, and Phase I requires all of our facilities in Virginia (including Clover) to acquire additional allowances required for each ton of SO_2 they emit beginning in 2010, and additional allowances per ton starting in 2015. We are entitled to sufficient SO_2 allowances because of our interest in Clover so that we do not anticipate needing to purchase additional SO_2 allowances for the Louisa, Marsh Run and Rock Springs generating facilities through both phases of CAIR.

Pursuant to the Clean Air Act and CAIR, both Virginia and Maryland have enacted regulations to reduce the emissions of NO_x by establishing NO_x cap and trade programs similar to the Federal SO_2 allowance programs. Both of these programs will meet the more stringent NO_x emission caps established under CAIR, and with respect to the facilities in Virginia, additional NO_x emission reductions mandated by Virginia. Under the CAIR program, allowances are required for annual NO_x emissions ("CAIRNO$_x$" allowances) and ozone season NO_x emissions ("CAIROS" allowances). Under the CAIR program, Clover is allocated a certain number of CAIRNO$_x$ and CAIROS allowances. If Clover emits more than the allotted allowances then CAIRNO$_x$ and CAIROS emissions allowances will have to be purchased. We can purchase CAIROS allowances from Virginia Power under an existing agreement or purchase them from the market. The agreement with Virginia Power provides us with the option each year to purchase from them the seasonal NO_x emissions allowances necessary to compensate for any shortfall between our seasonal NO_x emissions allowance requirement for Clover and our portion of the regulatory seasonal NO_x emissions allocation for Clover.

With respect to SO_2, under the Clean Air Act's Acid Rain Program, each of our fossil fuel-fired plants must obtain SO_2 allowances equal to the number of tons of SO_2 they emit into the atmosphere annually. The total number of allowances is capped, and allowances can be traded. As a facility that was built before the Acid Rain Program, Clover is included in the Acid Rain Program budget and receives an annual allocation of SO_2 allowances at no cost based upon its baseline operations. Newer facilities, including Louisa, Marsh Run and Rock Springs, need to obtain allowances; however, because they are primarily gas-fired, we expect the number of SO_2 allowances they must obtain will be minimal and will be supplied from excess SO_2 allowances allocated to Clover.

Louisa, Marsh Run and Rock Springs, our combustion turbine facilities, each produce NO_x emissions and all three sites have been allocated CAIRNO$_x$ and CAIROS emissions allowances under CAIR. The CAIRNO$_x$ and CAIROS allowances presently received are expected to cover the facilities emissions. NO_x emissions that are not covered by allowances will be purchased in the market for the operation of these facilities. We project that we will be able to obtain sufficient quantities of NO_x allowances in the future, but increased NO_x emissions or increased restrictions could cause the price of allowances to be higher than we currently expect.

Clear Air Mercury Rule

Clover is currently our only generating facility impacted by the Clean Air Mercury Rule ("CAMR"). In 2005, the EPA issued the CAMR which establishes caps for overall mercury emissions from coal-fired power plants. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's CAMR for controlling mercury emissions from coal-fired power plants. The EPA is currently reviewing the court's decisions and is evaluating the impacts of the ruling.

In 2006, Virginia adopted the cap and trade program proposed in CAMR, subject to certain limitations. The DEQ adopted the Mercury Budget Trading regulations in 2007 which are currently in effect. The 2008 U.S. Court of Appeals decision vacating CAMR does not affect the DEQ's adoption of the Mercury Budget Trading regulations; however, there will not be a cap and trade program if the CAMR ultimately does not go into effect. We do not anticipate that any additional measures will be required at Clover to comply with the DEQ's Mercury Budget Trading regulations due to Clover's existing pollution control requirement, which already removes greater than 90% of the mercury emitted from the facility.

Greenhouse Gas Initiative

In addition to traditional air pollutants, the issues concerning climate change have been the focus of much public attention. The Obama administration continues to pursue regulation of CO_2, particularly in light of the Copenhagen summit. A bill was passed in the House in 2009 containing provisions that would amend the Clean Air Act to establish a cap-and-trade system designed to reduce greenhouse gas emissions from covered sources 17% below 2005 levels by 2020 and 83% below 2005 levels by 2050. Many respondents had numerous concerns with the legislation, and of particular concern to ODEC was the formula for allowance allocation. It is anticipated that a draft of climate change legislation will be put before the Senate committees in 2010; however, it currently appears unlikely any final legislation will be passed in 2010. In addition to legislation and other rulemaking for cap and trade programs, the EPA is continuing to pursue other avenues for regulating greenhouse gas ("GHG") emissions.

Also, there are numerous actions at the state and regional level, including the Regional Greenhouse Gas Initiative ("RGGI") established in 2005 by the governors of seven Northeastern and Mid-Atlantic states, including Delaware. The RGGI provides for a cap and trade system to regulate CO_2 emissions among those states, capping emissions at current levels in 2009, and then reducing emissions 10% by 2019. In 2007, Maryland joined the RGGI. CO_2 emissions from Rock Springs require us to purchase emissions allowances. The regulations require all allowances to be auctioned rather than allocated directly to utilities.

We cannot exclude the possibility that future CO_2 emission regulations could have a significant effect on current operations, especially at Clover, as well as development of new generation; however, currently, we are not able to predict the final form of any such regulation.

Proposed Construction of Generation Facility

We are continuing to evaluate the feasibility of constructing a power station, which we anticipate would be fueled by a mixture of coal and biomass, a form of renewable energy, in either Surry or Sussex County, Virginia. See "—Power Supply Resources—Power Supply Planning" above. If constructed as currently contemplated, all of the environmental regulations applicable to Clover would also apply to this facility. However, no SO_2 allowances would be allocated to this facility. We have some excess SO_2 allowances that could be used at a new facility if constructed, and any shortfall would have to be purchased from the market. We currently expect that there would be an adequate number of allowances available at reasonable prices. Also, this proposed facility would apply for new source set-aside NO_x allowances, and it would purchase additional allowances from the market if there are not enough allowances to cover the emissions. We expect there would be an adequate amount of NO_x allowances available in the market at reasonable prices. This facility would be designed to allow future carbon capture technology to be installed.

Clean Water Act

The Clean Water Act and applicable state laws regulate water intake structures, discharges of cooling water, storm water run-off and other wastewater discharges at our generating facilities. We are in material compliance with these requirements and with permits that must be obtained with respect to such discharges. Our permits are subject to periodic review and renewal proceedings, and can be made more restrictive over time. Limitations on the thermal discharges in cooling water, or withdrawal of cooling water during low flow conditions, can restrict our operations. EPA has decided to revise the federal effluent guidelines for water discharges at power plants. In doing so, the agency is increasing their data-gathering efforts to better characterize steam-electric generating facilities.

Information Collection Request

In 2009, the EPA sent Clover an information collection request for hazardous air pollutants. This information is being collected by the EPA's Office of Air and Radiation to assist the EPA Administrator in developing Maximum Achievable Control Technology emission standards for fossil fuel-fired power plants of 25 megawatts or greater. Clover will conduct stack testing and fuel analyses and submit the information to the EPA during 2010. It is currently anticipated that the EPA will announce the emission standards in 2011.

Future Regulation

New legislative and regulatory proposals are frequently introduced on both a federal and state level that would modify the environmental regulatory programs applicable to our facilities. An example is the control of carbon dioxide and other greenhouse gases that may contribute to global climate change. With respect to proposed legislation and regulatory proposals that have not yet been formally proposed, we cannot provide meaningful predictions regarding their final form, or their possible effects upon our operations.

Nuclear

Under the Nuclear Waste Policy Act of 1982, the DOE is required to provide for the permanent disposal of spent nuclear fuel produced by nuclear facilities, such as North Anna, in accordance with contracts executed with the DOE. The DOE did not begin accepting spent fuel in 1998 as specified in its contract. Virginia Power is providing on-site spent nuclear fuel storage at the North Anna facility. Virginia Power will continue to manage its spent nuclear fuel until the DOE begins accepting the spent nuclear fuel. In 2004, Virginia Power filed a lawsuit seeking recovery of damages in connection with the DOE's failure to commence accepting spent nuclear fuel from North Anna. A subsequent trial held in 2008 ruled in favor of Virginia Power and the DOE filed an appeal. In March 2009, the Federal Circuit Court granted the DOE's request to stay the appeal. In November 2009, Virginia Power filed a motion to lift the stay and the DOE has opposed this motion. Once the stay is lifted, briefing on the appeal will occur.

ITEM 1A. – RISK FACTORS

RISK FACTORS

The following risk factors and all other information contained in this report should be considered carefully when evaluating ODEC. These risk factors could affect our actual results and cause these results to differ materially from those expressed in any forward-looking statements of ODEC. Other risks and uncertainties, in addition to those that are described below may also impair our business operations. We consider the risks listed below to be material, but you may view risks differently than we do and we may omit a risk that we consider immaterial but you consider important. An adverse outcome of any of the following risks could materially affect our business or financial condition. These risk factors should be read in conjunction with the other detailed information set forth in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7, including "Caution Regarding Forward Looking Statements."

We rely substantially on purchases of energy from other power suppliers which exposes us to market price risk and credit risk.

We supply our member distribution cooperatives with all of their power (capacity and energy) requirements, with limited exceptions. Our costs to provide this capacity and energy are passed through to our member distribution cooperatives under our wholesale power contracts. We obtain the power to serve their requirements from generating facilities in which we have an interest and purchases of power from other power suppliers.

Historically, our power supply strategy has relied substantially on purchases of energy from other power suppliers. In 2009, we purchased approximately 51.4% of our energy resources. These purchases consisted of a combination of purchases under physically-delivered forward contracts and purchases of energy in the spot market. Our reliance on purchases of energy from other suppliers will continue well into the future and likely will increase after 2009 as our member distribution cooperatives' requirements for power increase. Our reliance on energy purchases also could increase because the operation of our generation facilities is subject to many risks, including the shutdown of our facilities or breakdown or failure of equipment.

Purchasing power helps us mitigate high fixed costs relating to the ownership of generating facilities but exposes us, and consequently our member distribution cooperatives, to significant market price risk because energy prices can fluctuate substantially. When we enter into long-term power purchase contracts or agree to purchase energy at a date in the future, we utilize our judgment and assumptions in our models. These judgments and assumptions relate to factors such as future demand for power and market prices of energy and the price of commodities, such as natural gas, used to generate electricity. Our models cannot exactly predict what will actually occur and our results may vary from what our models predict, which may in turn impact our resulting costs to our members. Our models become less reliable the further into the future that the estimates are made. Although we have engaged APM to assist us in developing strategies to meet our power requirements in the most economical manner and we have implemented a hedging strategy to limit our exposure to variability in the market, we still may purchase energy at a price which is higher than other utilities' costs of generating energy or future market prices of energy. For further discussion of our market price risk, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk."

Changes in fuel and purchased power costs could increase our operating costs.

We are subject to changes in fuel costs, which could increase the cost of generating power, as well as changes in purchased power costs. Increases in fuel costs and purchased power costs increase the cost to our member distribution cooperatives. The market prices for fuel may fluctuate over relatively short periods of time. Factors that could influence fuel and purchased power costs are:

- Weather;
- Supply and demand;
- The availability of competitively priced alternative energy sources;
- The transportation of fuels;
- Price competition among fuels used to produce electricity, including natural gas, coal and crude oil;
- Energy transmission or natural gas transportation capacity constraints;
- Impact of implementation of new technologies in the power industry;
- Federal, state and local energy and environmental regulation and legislation; and
- Natural disasters, war, terrorism, and other catastrophic events.

Environmental regulation may limit our operations or increase our costs or both.

We currently are required to comply with numerous federal, state and local laws and regulations relating to the protection of the environment. While we believe that we have obtained all material environmental-related approvals currently required to own and operate our facilities or that these approvals have been applied for and will be issued in a timely manner, we may incur significant additional costs because of compliance with these requirements in addition to costs related to any costs of compliance with laws or regulations relating to CO_2 emissions. Failure to comply with environmental laws and regulations could have a material effect on us, including potential civil or criminal liability and the imposition of fines or expenditures of funds to bring our facilities into compliance. Delay in obtaining, or failure to obtain and maintain in effect any environmental approvals, or the delay or failure to satisfy any applicable environmental regulatory requirements related to the operation of our existing facilities or the sale of energy from these facilities could result in significant additional cost to us.

Regulation of carbon emissions, other greenhouse gases and other climate change related costs may significantly increase our costs and may result in our purchasing additional energy in the market.

Federal and state governmental authorities, prompted by growing concerns relating to the impact of global climate change, have begun to actively pursue legislation that calls for the reduction of emissions of GHG. Recently, legislative proposals have focused on regulation of CO_2 emissions. Often, these proposals either tax the emission of CO_2 or institute a cap and trade program requiring allowances to emit CO_2 in the operation of coal-fired generating facilities such as Clover. Cap and trade proposals vary regarding the extent to which existing generation facilities would be allocated allowances without cost, similar to the regulation of other emissions under the Clean Air Act. Some proposals do not allocate any allowances to existing facilities. Proposals requiring the taxing of CO_2 emissions vary widely as to the amount of the tax.

The additional costs related to a tax on CO_2 emissions or a cap and trade program could affect the relative cost of the energy generated by our facilities that burn coal and other fossil fuels. Because PJM dispatches facilities from lowest to highest cost, these additional costs may cause our CO_2 emitting generating facilities to be dispatched less often than they are currently. Lower levels of dispatch of these facilities by PJM likely would result in our purchasing more energy, potentially significantly more energy, from the market. The price of the additional energy purchased from the market in the future could be substantially higher than the current cost of the energy generated from our facilities emitting CO_2.

Because no federal laws or state laws applicable to us regulating CO_2 emissions have become effective, other than RGGI (see "Regulation—Greenhouse Gas Initiative"), we cannot predict the cost or the effect of any future legislation or regulation. We do believe, however, that some form of federal or state law or regulation in this area is likely to be enacted in the future and could have a material adverse effect on the cost of energy we supply our member distribution cooperatives. The Obama Administration has stated that it is going to pursue regulation of CO_2, including a cap and trade program aimed at greenhouse gas emissions. The administration has also proposed a federal renewable portfolio standard ("RPS") that may require us to produce or procure a significant portion of our energy needs from renewable resources, which may include sources that are more expensive than the costs associated with our existing generating units and market purchases. Because the details of this plan are not fully available, it is difficult for us to predict with any degree of certainty the magnitude of the impact a federal RPS would have on our costs and capital expenditures should this be enacted. Also, there are numerous actions at the state and regional level. New laws or regulations, the revision or reinterpretation of existing laws or regulations, or penalties imposed for non-compliance with existing laws or regulations may require us to incur additional expenses.

Our financial condition is largely dependent upon our member distribution cooperatives.

Our financial condition is largely dependent upon our member distribution cooperatives satisfying their obligations under their wholesale power contract that each has executed with us. The wholesale power contracts require our member distribution cooperatives to pay us for power furnished to them in accordance with our FERC formulary rate. Our board of directors, which is composed of representatives of our members, can approve changes in the rates we charge to our member distribution cooperatives without seeking FERC approval, with limited exceptions. In 2009, 55.0% of our revenues from sales to our member distribution cooperatives were received from our three largest members, Rappahannock Electric Cooperative, Delaware Electric Cooperative, Inc. and Choptank Electric Cooperative, Inc.

Our member distribution cooperatives' ability to collect their costs from their members may have an impact on our financial condition. Economic conditions may make it difficult for some consumers of our member distribution cooperatives to pay their power bills in a timely manner which may in turn affect the timeliness of our member distribution cooperatives payments to us. The broader economic downturn may also have an impact on the overall demand for electricity. Although it is difficult to predict with certainty the magnitude or duration of the current downturn, the occurrence of any of these trends may negatively affect our results of operations and financial position.

Adverse changes in our credit ratings could negatively impact our ability to access capital and may require us to provide credit support for some of our obligations.

Changes in our credit ratings could affect our ability to access capital. Standard & Poor's Ratings Services ("S&P"), Moody's Investors Service ("Moody's"), and Fitch Inc., currently rate our outstanding obligations issued under the Mortgage and Deed of Trust, dated as of May 1, 1992, with Crestar Bank (predecessor to U.S. Bank National Association), as trustee (the "Indenture") at "A," "A3," and "A," respectively. If these agencies were to downgrade our ratings, particularly below investment grade, we may be required to pay higher interest rates on financings which we may need to undertake in the future, and our potential pool of investors and funding sources could decrease. In addition, in limited circumstances, we have obligations to provide credit support if our obligations issued under the Indenture are rated below specified thresholds by S&P and Moody's. These circumstances relate to the lease and leaseback of our undivided interest in Clover Unit 1 and some of our power purchase contracts. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Significant Contingent Obligations" in Item 7.

To the extent that we would have to provide additional credit support as a result of a downgrade in our credit ratings, our ability to access additional credit may be limited and our liquidity, including our ability to service our outstanding indebtedness, may be materially impaired.

Failure of a certain investment in a lease of our interest in Clover Unit 1 could reduce investment income currently used to fund the majority of our rental payment obligations.

In conjunction with our 1996 lease and subsequent leaseback of our interest in Clover Unit 1, we purchased an investment that provides for a substantial portion of our periodic rent payments under the leaseback and the fixed purchase price of our interest in Unit 1 at the end of the term of the leaseback, if we were to exercise our option to purchase the interest at that time. The investment, which had a balance of $309.8 million at December 31, 2009, was issued by Cooperative Centrale Raiffeisen Boerenleenbank B.A., "Rabobank Nederland" ("Rabobank"), which has senior debt obligations which are currently rated "AAA" by S&P and "Aaa" by Moody's. If this entity fails to make disbursements from the investment, we remain liable for all rental payments under the leaseback and the fixed purchase price if we choose to exercise that option. At December 31, 2009, the total balance of our remaining lease obligation was $344.3 million. See "Significant Contingent Obligations – Lease of Clover Unit 1" in Item 7.

We may not be able to obtain funding on acceptable terms or at all because of the current state of the credit and capital markets. This may hinder or prevent us from meeting our future capital needs.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile due to a variety of factors, including significant write-offs in the financial services sector and the current weak economic conditions. As a result, the cost of raising money in the debt capital markets has increased substantially while the availability of funds from those markets has diminished significantly. In particular, as a result of concerns about the stability of financial markets generally and the solvency of lending counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt on similar terms or at all and reduced, or in some cases, ceased to provide funding to borrowers. In addition, lending counterparties under existing revolving credit facilities and other debt instruments may be unwilling or unable to meet their funding obligations. Due to these factors, we cannot be certain that new debt financing will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due.

The use of hedging instruments could impact our liquidity.

We use hedging instruments, including forwards, futures, financial transmission rights, and options, to manage our power market price risks. These hedging instruments generally include collateral requirements that require us to deposit funds or post letters of credit with counterparties when counterparty's credit exposure to us is in excess of agreed upon credit limits. When commodity prices decrease to levels below the levels where we have hedged future costs, we may be required to use a material portion of our cash or liquidity facilities to cover these collateral requirements.

Counterparties under power purchase arrangements may fail to perform their obligations to us.

Because we rely substantially on the purchase of energy from other power suppliers, we are exposed to the risk that counterparties will default in performance of their obligations to us. On an on-going basis we analyze and monitor the default risks of counterparties and other credit issues related to these purchases, and we may require our counterparties to post collateral with us; however, defaults may still occur. Defaults may take the form of failure to physically deliver the purchased energy. If a default occurs, we may be forced to enter into alternative contractual arrangements or purchase energy in the forward, short-term or spot markets at then-current market prices that may exceed the prices previously agreed upon with the defaulting counterparty.

We are subject to risks associated with owning an interest in a nuclear generation facility.

We have an 11.6% undivided ownership interest in North Anna which provided approximately 18.0% of our energy requirements in 2009. Ownership of an interest in a nuclear generating facility involves risks, including:

- potential liabilities relating to harmful effects on the environment and human health resulting from the operation of the facility and the storage, handling and disposal of radioactive materials;

- significant capital expenditures relating to maintenance, operation and repair of the facility, including repairs required by the NRC;

- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with operation of the facility; and

- uncertainties regarding the technological and financial aspects of decommissioning a nuclear plant at the end of its licensed life.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of North Anna. If the facility is not in compliance, the NRC may impose fines or shut down one or both units until compliance is achieved, or both depending upon its assessment of the situation. Revised safety requirements issued by the NRC have, in the past, necessitated substantial capital expenditures at other nuclear generating facilities. In addition, although we have no reason to anticipate a serious nuclear incident at North Anna, if an incident did occur, it could have a material but presently undeterminable adverse effect on our operations or financial condition. Further, any unexpected shut down at North Anna as a result of regulatory non-compliance or unexpected maintenance will require us to purchase replacement energy. We can buy this replacement power either from Virginia Power or the market. See "Power Supply Resources—Power Purchase Contracts."

NERC Compliance.

As a result of the Energy Policy Act 2005 ("EPACT"), owners, operators and users of bulk electric systems, including ODEC, are subject to mandatory reliability standards enacted by the North American Electric Reliability Corporation ("NERC") and its regional entities and enforced by FERC. We must follow these standards, which are in place to require that proper functions are performed to ensure the reliability of the bulk power system. Although the standards are developed by the NERC Standards Committee, which includes representatives of various electric energy sectors, and must be just and reasonable, the standards are legally binding and compliance may require increased capital expenditures and costs to provide electricity to our member distribution cooperatives under our wholesale power contracts. If we are found to be in non-compliance with any mandatory reliability standards we would be subject to sanctions, including potentially substantial monetary penalties.

Failure to retain and attract key executive officers and other skilled employees could have an adverse impact on our operations.

We are subject to employee workforce factors including retirement and loss of key executives or other employees and the availability of qualified personnel. The energy business is dependent on retaining and recruiting personnel with experience in sophisticated energy transactions and operations.

Poor market performance will affect our nuclear decommissioning trust asset values and our defined benefit retirement plans, which may increase our costs.

We are required to maintain a funded trust to satisfy our future obligation to decommission the North Anna facility. A decline in the market value of those assets due to poor investment performance or other factors may increase our funding requirements for these obligations which may increase our costs.

We participate in the National Rural Electric Cooperatives Association ("NRECA") Retirement Security Plan and the pension restoration plan. The cost of these plans is funded by our payments to NRECA. Poor performance of investments in these benefit plans may increase our costs.

Potential changes in accounting practices may adversely affect our financial results.

We cannot predict the impact that future changes in accounting standards or practices may have on public companies in general, the energy industry or our operations specifically. New accounting standards could be issued that could change the way we record revenues, expenses, assets and liabilities. These changes in accounting standards could adversely affect our reported earnings or could increase reported liabilities.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

Our principal properties consist of our interest in five electric generating facilities, additional distributed generation facilities across our member distribution cooperatives' service territories and a limited amount of transmission facilities. All of our physical properties are subject to the lien of our Indenture. See "Restated Indenture" below. Our generating facilities consist of the following:

Generating Facility	Ownership Interest	Location	Primary Fuel	Commercial Operation Date	Net Capacity Entitlement[3]
Clover	50.0%[1]	Halifax County, Virginia	Coal	Unit 1 – 10/1995	215 MW
				Unit 2 – 03/1996	215 MW
					430 MW
North Anna	11.6%	Louisa County, Virginia	Nuclear	Unit 1 – 06/1978 [4]	107 MW
				Unit 2 – 12/1980 [4]	107 MW
					214 MW
Louisa	100.0%	Louisa County, Virginia	Natural	Unit 1 – 06/2003	84 MW
			Gas [5]	Unit 2 – 06/2003	84 MW
				Unit 3 – 06/2003	84 MW
				Unit 4 – 06/2003	84 MW
				Unit 5 – 06/2003	168 MW
					504 MW
Marsh Run	100.0%	Fauquier County, Virginia	Natural	Unit 1 – 09/2004	168 MW
			Gas [5]	Unit 2 – 09/2004	168 MW
				Unit 3 – 09/2004	168 MW
					504 MW
Rock Springs	50.0%[2]	Cecil County, Maryland	Natural	Unit 1 – 06/2003	168 MW
			Gas	Unit 2 – 06/2003	168 MW
					336 MW
Distributed Generation	100.0%	Multiple	Diesel	10 units – 07/2002	20 MW
				Total	2,008 MW

(1) Our interest in Clover Unit 1 is subject to a long-term lease. See "Clover" below.
(2) We own 100% of two units, each with a net capacity rating of 168 MW, and 50% of the common facilities for the facility. See "Combustion Turbine Facilities—Rock Springs" below.
(3) Represents an approximation of our entitlement to the maximum dependable capacity, which does not represent actual usage.
(4) We purchased our 11.6% undivided ownership interest in North Anna in December 1983.
(5) The units at this facility also operate on No. 2 distillate fuel oil.

Clover

We, along with Virginia Power are co-owners of Clover. Virginia Power is responsible for operating Clover and procuring and arranging for the transportation of the fuel required to operate Clover. See "Power Supply Resources—Fuel Supply—Coal" in Item 1. We are responsible for and must fund half of all additions and operating costs associated with Clover, as well as half of Virginia Power's administrative and general expenses for Clover. Under the terms of the Clover operating agreement, ODEC and Virginia Power each take half of the power produced by Clover.

Lease of Clover Unit 1

In 1996, we entered into a lease with an owner trust for the benefit of an investor in which we leased our interest in Clover Unit 1 and related common facilities, subject to the lien of the Indenture, for a term extendable by the owner trust up to the full productive life of Clover Unit 1, and simultaneously entered into an approximately 21.8 year leaseback of the interest. If the lien of the Indenture is released, the interest of the owner trust in Clover Unit 1 would no longer be subject and subordinate to the lien of the Indenture in the future. See "Restated Indenture" below. The lease contains events of default, which, if they occur, could result in termination of the lease, and, consequently, our loss of possession and right to the output of Clover Unit 1. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Significant Contingent Obligations—Lease of Clover Unit 1" in Item 7 for a discussion of our options and obligations at the end of the term of the leaseback of Clover Unit 1 and sources of funding for these obligations.

North Anna

Virginia Power, the co-owner of North Anna, is responsible for operating North Anna. Virginia Power also has the authority and responsibility to procure nuclear fuel for North Anna. See "Fuel Supply—Nuclear" in Item 1. We are entitled to 11.6% of the power generated by North Anna. Additionally, we are responsible for and must fund 11.6% of all post-acquisition date additions and operating costs associated with North Anna, as well as a pro-rata portion of Virginia Power's administrative and general expenses directly attributable to North Anna. In addition, we separately fund our pro-rata portion of the decommissioning costs of North Anna. ODEC and Virginia Power also bear pro-rata any liability arising from ownership of North Anna, except for liabilities resulting from the gross negligence of the other.

In 2007, Virginia Power and ODEC filed a joint application with the NRC for a license to construct and operate a new reactor at North Anna. We expect the application review to take at least three years. We will continue to further evaluate the project and make a final determination as to our future involvement. See "Business—Power Supply Planning" in Item 1.

Combustion Turbine Facilities

Louisa

We are responsible for the operation and maintenance of the Louisa facility and we supply all services, goods and materials required to operate and maintain the facility, including arranging for the transportation and supply of the natural gas and No. 2 distillate fuel oil required by the facility.

Marsh Run

We are also responsible for the operation and maintenance of the Marsh Run facility and we supply all services, goods and materials required to operate and maintain the facility, including arrangement for the transportation and supply of the natural gas and No. 2 distillate fuel oil required by the facility.

Rock Springs

ODEC and North American Energy Alliance, LLC ("NAEA") each individually own two units (a total of 336 MWs each) and 50% of the common facilities at the Rock Springs facility. Additionally, ODEC and NAEA each individually dispatch its respective units as determined to be necessary and prudent. The facility is currently permitted to allow two additional 168 MW combustion turbines to be installed at the site for a total site capacity of 1,008 MW.

The Rock Springs facility is currently operated and maintained by North American Energy Alliance Operating Co., LLC, an affiliate of NAEA, pursuant to a service agreement under which North American Energy Alliance Operating Co., LLC, supplies all services, goods and materials, other than natural gas, required to operate the facility. We are responsible for all costs associated with the development, construction, additions and operating costs and administrative and general expenses relating to our two units and the proportional share of the costs relating to the common facilities for Rock Springs.

We arrange for the transportation of the natural gas required by the operator for all units at Rock Springs and arrange for the supply of natural gas to our units only.

Distributed Generation Facilities

We have distributed generation facilities in our member distribution cooperatives' service territory primarily to enhance our system's reliability. Four diesel generators service our member distributions cooperatives' in the Virginia mainland territory and six diesel generators service our member distribution cooperatives' in the Delmarva Peninsula territory.

Transmission

We own approximately 100 miles of transmission lines on the Virginia portion of the Delmarva Peninsula. We also own two 1,100 foot 500 kilovolt ("kV") transmission lines and a 500 kV substation at the Rock Springs site jointly with NAEA. As a transmission owner in PJM, we have relinquished control of all of these transmission facilities to PJM and contracted with third parties to operate and maintain them.

Restated Indenture

In 2001, we entered into a supplemental indenture to the Indenture that contains provisions, which, if they become effective, will amend and restate the Indenture to release its lien on our property. This amended and restated indenture (the "Restated Indenture") will become effective when all obligations under the Indenture issued prior to September 1, 2001, cease to be outstanding or when the holders of those obligations consent to the effectiveness of the Restated Indenture. We have $1.0 million of obligations issued under the Indenture prior to September 1, 2001, the holders of which have not consented to the effectiveness of the Restated Indenture. We have the ability to redeem these obligations on any June 1 or December 1, following appropriate notice to the holders of those obligations. The amendment and restatement may not occur, however, if, immediately afterwards, an event of default exists under the Indenture or an event of default would occur. After the date the Restated Indenture becomes effective, the obligations outstanding under the Restated Indenture will be unsecured general obligations, ranking equally and ratably with all of our other unsecured and unsubordinated obligations.

ITEM 3. LEGAL PROCEEDINGS

Norfolk Southern

We and Virginia Power have been parties to a contract dispute with a fuel transportation supplier, Norfolk Southern Railway Company ("Norfolk Southern"), in the Circuit Court of Halifax County, Virginia. On October 30, 2009, we and Virginia Power settled our contract dispute with Norfolk Southern. Under the terms of the settlement, we and Virginia Power agreed to pay Norfolk Southern approximately $10.8 million in damages, representing underpayments made to Norfolk Southern from December 1, 2003 through the present. Our share of the settlement amount is approximately $5.4 million. A regulatory liability of $63.5 million was established for the difference between the amount previously accrued and collected and the settlement amount. Also, as part of the settlement, the parties agreed on the fourth quarter 2009 adjusted base rates, which will be adjusted on a quarterly basis under the terms of the parties' coal transportation agreement.

In 2008, we, along with Virginia Power, filed a separate suit against Norfolk Southern in the Circuit Court of the City of Richmond, Virginia, seeking to recover approximately $4.9 million, plus interest, for unauthorized fuel surcharges improperly collected by Norfolk Southern under our coal transportation agreement. Our portion of this claim is approximately $2.5 million, excluding interest. We believe that the fuel surcharge conflicts with the payment provisions specified in the agreement. The parties are currently engaged in discovery.

Other

Other than the issues discussed above and certain other legal proceedings arising out of the ordinary course of business that management believes will not have a material adverse impact on our results of operations or financial condition, there is no other litigation pending or threatened against us.

ITEM 4. RESERVED

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Not Applicable

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data below present selected historical information relating to our financial condition and results of operations. The financial data for the five years ended December 31, 2009, are derived from our audited consolidated financial statements. You should read the information contained in this table together with our consolidated financial statements, the related notes to the consolidated financial statements, and the discussion of this information in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(in thousands, except ratios)				
Statement of Operations Data					
Operating Revenues	$ 713,169	$ 1,040,751	$ 963,094	$ 817,515	$ 737,679
Operating Margin	57,736	61,417	62,085	73,461	68,196
Net Margin[(1)]	9,687	11,784	16,035	21,244	12,109
Margins for Interest Ratio	1.21	1.23	1.30	1.39	1.22

	December 31,				
	2009	2008	2007	2006	2005
	(in thousands, except ratios)				
Balance Sheet Data					
Net Electric Plant	$ 1,008,373	$ 1,016,579	$ 1,031,727	$ 1,059,745	$ 1,085,714
Investments	176,076	199,129	334,269	286,956	254,813
Other Assets	255,463	290,037	305,751	280,708	371,839
Total Assets	$ 1,439,912	$ 1,505,745	$ 1,671,747	$ 1,627,409	$ 1,712,366
Patronage capital	$ 329,520	$ 319,833	$ 309,112	$ 293,077	$ 271,833
Non-controlling interest	13,178	12,787	11,431	10,993	25,062
Long-term debt	688,736	711,675	787,028	813,264	832,980
Total Capitalization	$ 1,031,434	$ 1,044,295	$ 1,107,571	$ 1,117,334	$ 1,129,875
Equity Ratio[(2)]	32.4%	31.0%	28.2%	26.5%	24.6%

(1) Net Margin for 2007 and 2006 includes an additional equity contribution of $4.0 million and $9.0 million, respectively.
(2) Equity ratio equals patronage capital divided by the sum of our long-term debt and patronage capital.

Our Indenture obligates us to establish and collect rates for service to our member distribution cooperatives, which are reasonably expected to yield a margin for interest ratio for each fiscal year equal to at least 1.10, subject to any necessary regulatory or judicial approvals. The Indenture requires that these amounts, together with other moneys available to us, provide us moneys sufficient to remain in compliance with our obligations under the Indenture. We calculate the margins for interest ratio by dividing our margins for interest by our interest charges.

Margins for interest under the Indenture equal:

- our net margins;
- plus revenues that are subject to refund at a later date which were deducted in the determination of net margins;
- plus non-recurring charges that may have been deducted in determining net margins;
- plus total interest charges (calculated as described below);
- plus income tax accruals imposed on income after deduction of total interest for the applicable period.

In calculating margins for interest under the Indenture, we factor in any item of net margin, loss, income, gain, earnings or profits of any of our affiliates or subsidiaries, only if we have received those amounts as a dividend or other distribution from the affiliate or subsidiary or if we have made a contribution to, or payment under a guarantee or like agreement for an obligation of, the affiliate or subsidiary. Any amounts that we are required to refund in subsequent years do not reduce margins for interest as calculated under the Indenture for the year the refund is paid.

Interest charges under the Indenture equal our total interest charges (other than capitalized interest) related to (1) all obligations under the Indenture, (2) indebtedness secured by a lien equal or prior to the lien of the Indenture, and (3) obligations secured by liens created or assumed in connection with a tax-exempt financing for the acquisition or construction of property used by us, in each case including amortization of debt discount and expense or premium.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Caution Regarding Forward Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward looking statements regarding matters that could have an impact on our business, financial condition, and future operations. These statements, based on our expectations and estimates, are not guarantees of future performance and are subject to risks, uncertainties, and other factors that could cause actual results to differ materially from those expressed in the forward looking statements. These risks, uncertainties, and other factors include, but are not limited to, general business conditions, increased competition in the electric utility industry, demand for energy, federal and state legislative and regulatory actions and legal and administrative proceedings, changes in and compliance with environmental laws and policies, general credit and capital market conditions, weather conditions, the cost of commodities used in our industry, and unanticipated changes in operating expenses and capital expenditures. Our actual results may vary materially from those discussed in the forward looking statements as a result of these and other factors. Any forward looking statement speaks only as of the date on which the statement is made, and we undertake no obligation to update any forward looking statement or statements to reflect events or circumstances after the date on which the statement is made even if new information becomes available or other events occur in the future.

Basis of Presentation

The accompanying financial statements reflect the consolidated accounts of ODEC, its subsidiaries and TEC. See "Note 1—Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements in Item 8".

Overview

We are a not-for-profit power supply cooperative owned entirely by our eleven Class A member distribution cooperatives and a Class B member, TEC. We supply our member distribution cooperatives' power requirements, consisting of capacity requirements and energy requirements, through a portfolio of resources including generating facilities, long-term and short-term physically-delivered forward power purchase contracts, and spot market purchases.

Our financial results for the year ended December 31, 2009, were significantly impacted by:

- Change in the number of members we serve (see "Member Distribution Cooperatives" below);
- Lower purchased power costs and volume;
- Acquisition of a loan and liquidation of an investment related to the lease and leaseback of our interest in Clover Unit 1 and the resulting defeasance of the loan;
- Establishment of a regulatory liability related to the settlement of a dispute with Norfolk Southern; and
- Scheduled maintenance for both units at Clover and one unit at North Anna.

Member Distribution Cooperatives

Beginning January 1, 2009, we serve eleven member distribution cooperatives and supply their power requirements. In 2008, we served these eleven member distribution cooperative plus another, Northern Virginia Electric Cooperative ("NOVEC"). In 2008, we entered into a settlement, release and withdrawal agreement (the "Withdrawal Agreement") with NOVEC to end our power supply arrangement and to resolve all of our outstanding disputes with it. The Withdrawal Agreement resulted in the termination of NOVEC's wholesale power contract with ODEC and the withdrawal of NOVEC as a member of ODEC effective as of December 31, 2008.

Critical Accounting Policies

The preparation of our financial statements in conformity with generally accepted accounting principles requires that our management make estimates and assumptions that affect the amounts reported in our financial statements. We base these estimates and assumptions on information available as of the date of the financial statements and they are not necessarily indicative of the results to be expected for the year. We consider the following accounting policies to be critical accounting policies due to the estimation involved in each.

Accounting for Rate Regulation

We are a rate-regulated entity and, as a result, are subject to the accounting requirements of Accounting for Regulated Operations. In accordance with Accounting for Regulated Operations, some of our revenues and expenses can be deferred at the discretion of our board of directors, which has budgetary and rate setting authority, if it is probable that these amounts will be refunded or recovered through our formulary rate in future years. Regulatory assets on our Consolidated Balance Sheet are costs that we expect to recover from our member distribution cooperatives based on rates approved by our board of directors in accordance with our formulary rate. Regulatory liabilities on our Consolidated Balance Sheet represent probable future reductions in our revenues associated with amounts that we expect to refund to our member distribution cooperatives based on rates approved by our board of directors in accordance with our formulary rate. See "—Factors Affecting Results—Formulary Rate" below. Regulatory assets are generally included in deferred charges and regulatory liabilities are generally included in deferred credits and other liabilities. We recognize regulatory assets and liabilities as expenses or as a reduction in expenses, concurrent with their recovery through rates.

Deferred Energy

In accordance with Accounting for Regulated Operations, we use the deferral method of accounting to recognize differences between our energy expenses and our energy revenues collected from our member distribution cooperatives. Deferred energy expense on our Consolidated Statement of Revenues, Expenses and Patronage Capital represents the difference between energy revenues and energy expenses. The deferred energy balance on our Consolidated Balance Sheet represents the net accumulation of any under- or over-collection of energy costs. Under-collected energy costs appear as an asset on our Consolidated Balance Sheet and will be collected from our member distribution cooperatives in subsequent periods through our formulary rate. Conversely, over-collected energy costs appear as a liability on our Consolidated Balance Sheet and will be refunded to our member distribution cooperatives in subsequent periods through our formulary rate.

Margin Stabilization Plan

We have a Margin Stabilization Plan that allows us to review our actual capacity-related costs of service and capacity revenue and adjust revenues from our member distribution cooperatives to meet our financial coverage requirements and accumulate additional equity as approved by our board of directors. Our formulary rate allows us to recover and refund amounts under the Margin Stabilization Plan. We record all adjustments, whether increases or decreases, in the year affected and allocate any adjustments to our member distribution cooperatives based on power sales during that year. We collect these increases from our member distribution cooperatives, or offset decreases against amounts owed by our member distribution cooperatives to us, generally in the succeeding calendar year. Each quarter we adjust revenues and accounts payable—members or accounts receivable—members, as appropriate, to reflect these adjustments. In 2009, 2008, and 2007, under our Margin Stabilization Plan, we reduced operating revenues by $2.4 million, $11.3 million, and $30.5 million, respectively, and increased accounts payable—members by the same amount.

Accounting for Asset Retirement Obligations

Accounting for Asset Retirement and Environmental Obligations requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. In the absence of quoted market prices, we estimate the fair value of our asset retirement obligations using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit-adjusted risk-free rate. Asset retirement obligations currently reported on our Consolidated Balance Sheet were measured during a period of historically low interest rates. The impact on measurements of new asset retirement obligations using different rates in the future may be significant.

Accounting for Asset Retirement and Environmental Obligations also requires the establishment of a liability for conditional asset retirement obligations. A conditional asset retirement obligation is a 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. Uncertainty about the timing and/or method of settlement is required to be considered in the measurement of the liability when sufficient information exists.

A significant portion of our asset retirement obligations relates to our share of the future cost to decommission North Anna. At December 31, 2009, North Anna's nuclear decommissioning asset retirement obligation totaled $59.0 million, which represented approximately 91.4 % of our total asset retirement obligations. Because of its significance, the following discussion of critical assumptions inherent in determining the fair value of asset retirement obligations relates to those associated with our nuclear decommissioning obligations.

We obtain from third-party experts periodic site-specific "base year" cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for North Anna. Our current estimate is based upon studies that were performed in 2009 and adopted effective July 1, 2009. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual results. In addition, these estimates are dependent on subjective factors, including the selection of cost escalation rates, which we consider to be a critical assumption.

We determine cost escalation rates, which represent projected cost increases over time, due to both general inflation and increases in the cost of specific decommissioning activities. The following table details the weighted average cost escalation rates used by the study:

Year Study Performed	Weighted Average Cost Escalation Rate
2002	3.27%
2005	2.42
2009	2.30

The weighted average cost escalation rate was applied if the cash flows increased as compared to the previous study. The original weighted average cost escalation rate was applied if the cash flows decreased as compared to the previous study. The use of alternative rates would have been material to the liabilities recognized. For example, had we increased the cost escalation rates by 0.5%, the amount recognized as of December 31, 2009, for our asset retirement obligations related to nuclear decommissioning would have been $12.5 million higher.

Accounting for Derivative Contracts

We primarily purchase power under both long-term and short-term physically-delivered forward contracts to supply power to our member distribution cooperatives under our wholesale power contracts with them. These forward purchase contracts meet the accounting definition of a derivative; however, a majority of the forward purchase derivative contracts qualify for the normal purchases/normal sales accounting exception under Accounting for Derivatives and Hedging. As a result, these contracts are not recorded at fair value. We record a liability and purchased power expense when the power under the forward physical delivery contract is delivered. We also purchase natural gas futures generally for three years or less to hedge the price of natural gas for the operation of our combustion turbine facilities and for use as a basis in determining the price of power in certain forward power purchase agreements. These derivatives do not qualify for the normal purchases/normal sales accounting exception.

For all derivative contracts that do not qualify for the normal purchases/normal sales accounting exception, we may elect cash flow hedge accounting in accordance with Accounting for Derivatives and Hedging. Accordingly, gains and losses on derivative contracts are deferred into Other Comprehensive Income until the hedged underlying transaction occurs or is no longer likely to occur. For derivative contracts where hedge accounting is not utilized, or for which ineffectiveness exists, we defer all remaining gains and losses on a net basis as a regulatory asset or liability in accordance with Accounting for Regulated Operations. These amounts are subsequently reclassified as purchased power or fuel expense in our Consolidated Statements of Revenues, Expenses and Patronage Capital as the power or fuel is delivered and/or the contract settles.

Generally, derivatives are reported at fair value on the Consolidated Balance Sheet in the regulatory asset/liability accounts and deferred charges–other and deferred credits and other liabilities–other. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including broker quotes and industry publications. For individual contracts, the use of differing assumptions could have a material effect on the contract's estimated fair value.

Factors Affecting Results

Formulary Rate

Our power sales are comprised of two power products – energy and capacity (also referred to as demand). Energy is the physical electricity delivered through transmission and distribution facilities to customers. We must have sufficient committed energy available to us for delivery to our member distribution cooperatives to meet their maximum energy needs at any time, with limited exceptions. This committed available energy at any time is referred to as capacity.

The rates we charge our member distribution cooperatives for sales of energy and capacity are determined by a formulary rate accepted by FERC which is intended to permit collection of revenues which will equal the sum of:

- all of our costs and expenses;
- 20% of our total interest charges; and
- additional equity contributions approved by our board of directors.

The formulary rate has three main components: a demand rate, a base energy rate and a fuel factor adjustment rate. The formulary rate identifies the cost components that we can collect through rates, but not the actual amounts to be collected. With limited minor exceptions, we can change our rates periodically to match the costs we have incurred and we expect to incur without seeking FERC approval.

Energy costs, which are primarily variable costs, such as nuclear, coal and natural gas fuel costs and the energy costs under our power purchase contracts with third parties, are recovered through two separate rates, the base energy rate and the fuel factor adjustment rate. The base energy rate is a fixed rate that requires FERC approval prior to adjustment. However, to the extent the base energy rate over- or under-collects our energy costs, we refund or collect the difference through a fuel factor adjustment rate. We review our energy costs at least every six months to determine whether the base energy rate and the current fuel factor adjustment rate together are adequately recovering our actual and anticipated energy costs, and revise the fuel factor adjustment rate accordingly. Since the fuel factor adjustment rate can be revised without FERC approval, we can effectively change our total energy rate to recover all our energy costs without seeking the approval of FERC.

Capacity costs, which are primarily fixed costs, such as depreciation expense, interest expense, administrative and general expenses, capacity costs under power purchase contracts with third parties, transmission costs, and our margin requirements and additional equity contributions approved by our board of directors are recovered through our demand rate. The formulary rate allows us to change the actual demand rate we charge as our capacity related costs change, without seeking FERC approval, with the exception of decommissioning cost, which is a fixed number in the formulary rate that requires FERC approval prior to any adjustment. FERC approval is also needed to change account classifications currently in the formula or to add accounts not otherwise included in the current formula. Additionally, future depreciation studies are to be filed with FERC for their approval if they would result in a change in our depreciation rates. Our demand rate is revised automatically to recover the costs contained in our budget and any revisions made by our board of directors to our budget.

We may revise our budget at any time to the extent that our current budget does not accurately reflect our demand (or capacity)-related costs and expenses or estimates of our demand sales of power. Increases or decreases in our budget automatically amend the demand component of our formulary rate. The formulary rate also permits us to adjust the amounts to be collected from the member distribution cooperatives to equal our actual demand costs. We make these adjustments under our Margin Stabilization Plan. See "—Critical Accounting Policies—Margin Stabilization Plan." These adjustments are treated as due, owed, incurred and accrued for the year to which the increase or decrease relates. The member distribution cooperatives generally pay or receive any amounts owed to or by us as a result of this adjustment in the following year. If at any time our board of directors determines that the formula does not meet all of our costs and expenses, it may adopt a new formula to meet those costs and expenses, subject to any necessary regulatory review and approval.

Margins

We operate on a not-for-profit basis and, accordingly, seek to generate revenues sufficient to recover our cost of service and produce margins sufficient to establish reasonable reserves, meet financial coverage requirements, and accumulate additional equity approved by our board of directors. Revenues in excess of expenses in any year are designated as net margins in our Consolidated Statements of Revenues, Expenses and Patronage Capital. We designate retained net margins in our Consolidated Balance Sheets as patronage capital, which we assign to each of our members on the basis of its class of membership and business with us. Any distributions of patronage capital are subject to the discretion of our board of directors and restrictions contained in our Indenture.

Recognition of Revenue

Our operating revenues on our Consolidated Statement of Revenues, Expenses and Patronage Capital reflect the actual capacity-related costs we incurred plus the energy costs that we collected during each calendar quarter and at year-end. Estimated capacity-related costs are collected during the period through the demand component of our formulary rate. In accordance with our Margin Stabilization Plan, these costs, as well as operating revenues, are adjusted at the end of each reporting period to reflect actual capacity-related costs incurred during that period. See "—Critical Accounting Policies—Margin Stabilization Plan." Estimated energy costs are collected during the period through the base energy rate and the fuel factor adjustment rate. Operating revenues are not adjusted at the end of each reporting period to reflect actual costs incurred during that period. The difference between actual energy costs incurred and energy costs collected during each period is recorded as deferred energy expense. See "—Critical Accounting Policies—Deferred Energy."

We bill capacity to each of our member distribution cooperatives based on its requirement for energy during the hour of the month when the need for energy among all of the consumers in the Virginia mainland or the Delmarva Peninsula, as applicable, is highest, as measured in MW. We bill energy to each of our member and non-member customers based on the total megawatt hours ("MWh") delivered to them each month.

Consumers' Requirements for Power

Growth in the number of consumers and growth in consumers' requirements for power significantly affect our member distribution cooperatives' consumers' requirements for power. Factors affecting our member distribution cooperatives' consumers' requirements for power include:

- *Weather* – Weather affects the demand for electricity. Relatively higher or lower temperatures tend to increase the demand for energy to use air conditioning and heating systems. Mild weather generally reduces the demand because heating and air conditioning systems are operated less. Weather also plays a role in the price of market energy through its effects on the market price for fuel, particularly natural gas. For example, hurricanes in the Gulf of Mexico can affect the supply of natural gas and its market price.

- *Economy* – General economic conditions have an impact on the rate of growth of our member distribution cooperatives' energy requirements.

- *Residential growth* – The increase in the rate of residential growth in our member distribution cooperatives' service territories increases the requirements for power.

- *Commercial growth* – The amount, size and usage of electronics and machinery and the expansion of operations among our member distribution cooperatives' commercial and industrial customers impacts the requirements for power.

Power Supply Resources

In an attempt to provide stable power costs to our member distribution cooperatives, we utilize a combination of our owned generating resources and purchases from the market. We also regularly review options for future power sources, including additional owned generation and power purchase contracts.

Market forces influence the structure and price of new power supply contracts into which we enter. When we enter into long-term power purchase contracts or agree to purchase energy at a date in the future, we rely on models based on our judgments and assumptions of factors such as future demand for power and market prices of energy and the price of commodities, such as natural gas used to generate electricity. Our actual results may vary from what our models predict, which may in turn impact our resulting costs to our members. Additionally, our models become less reliable the further into the future that the estimates are made.

In 2009, we satisfied the majority of our member distribution cooperatives' capacity requirements and approximately half of their energy requirements through our ownership interests in Clover, North Anna, Louisa, Marsh Run, and Rock Springs, and we purchased power under physically-delivered forward contracts and in the spot market to supply the remaining needs of our member distribution cooperatives. See "Power Supply Resources" in Item 1 and "Properties" in Item 2.

Generating Facilities

Our operating expenses, and consequently our rates to our member distribution cooperatives, are significantly affected by the operations of our baseload generating facilities, Clover and North Anna. Baseload generating facilities, particularly nuclear power plants such as North Anna, generally have relatively high fixed costs. Nuclear facilities operate with relatively low variable costs due to lower fuel costs and technological efficiencies. In addition, coal-fired facilities have relatively low variable costs, as compared to combustion turbine facilities such as Louisa, Marsh Run and Rock Springs. Our combustion turbine facilities have relatively low fixed costs and greater operational flexibility; however, they are more expensive to operate and, as a result, we operate them only when the market price of energy makes their operation economical or when their operation is required by PJM for system reliability purposes. Owners of power plants incur the fixed costs of these facilities whether or not the units operate. The output of Clover and North Anna for the past three years as a percentage of maximum dependable capacity rating of the facilities was as follows:

	Clover			**North Anna**		
	Year Ended December 31,			**Year Ended December 31,**		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**
Unit 1	74.6%	76.9%	87.2%	92.3%	100.7%	89.1%
Unit 2	72.2	76.0	88.0	99.9	81.3	85.0
Combined	73.4	76.5	87.6	96.1	91.0	87.1

The scheduled and unscheduled outages for Clover for the past three years were as follows:

	Scheduled Outages Year Ended December 31,			Unscheduled Outages Year Ended December 31,		
	2009	2008	2007	2009	2008	2007
		(in days)			(in days)	
Unit 1	54.8	18.5	14.4	4.3	4.3	5.1
Unit 2	53.1	14.5	13.4	10.9	6.8	4.0
Combined	107.9	33.0	27.8	15.2	11.1	9.1

Also, the production for Clover Unit 2 was curtailed approximately 1.0 day in 2009 and 13.3 days in 2008 due to equipment issues.

The scheduled and unscheduled outages for North Anna for the past three years were as follows:

	Scheduled Outages Year Ended December 31,			Unscheduled Outages Year Ended December 31,		
	2009	2008	2007	2009	2008	2007
		(in days)			(in days)	
Unit 1	25.1	-	33.0	5.8	-	4.0
Unit 2	-	31.0	35.8	3.0	37.8	15.6
Combined	25.1	31.0	68.8	8.8	37.8	19.6

The operational availability of our Louisa, Marsh Run and Rock Springs combustion turbine facilities for the past three years was as follows:

	Operational Availability Year Ended December 31,		
	2009	2008	2007
Louisa	98.2%	98.2%	95.7%
Marsh Run	97.3	97.9	98.7
Rock Springs	94.6	98.3	99.2

Increasing Environmental Regulation

We are subject to extensive federal and state regulation regarding environmental matters. This regulation is becoming increasingly stringent through amendments to federal and state statutes and the development of regulations authorized by existing law, including regulation related to CO_2 and other GHGs. Future federal and state legislation and regulations, particularly with respect to GHGs, present the potential for even greater obligations to limit the impact on the environment from the operation of our generation and transmission facilities. See "Risk Factors" in Item 1A.

Results of Operations

Operating Revenues

Our operating revenues are derived from power sales to our member distribution cooperatives and non-members. Our operating revenues by type of purchaser for the past three years were as follows:

	Operating Revenues Year Ended December 31,		
	2009	2008	2007
Revenues from sales to:		(in thousands)	
Member distribution cooperatives	$ 679,075	$ 965,475	$ 856,430
Non-members	34,094	75,276	106,664
Total revenues	$ 713,169	$ 1,040,751	$ 963,094

Energy and Demand Sales Volumes

Our energy sales in MWh to our member distribution cooperatives and non-members for the past three years were as follows:

	Energy Sales Volume Year Ended December 31,		
	2009	2008	2007
Energy sales to:		(in MWh)	
Member distribution cooperatives	8,667,917	12,208,886	11,849,698
Non-members	1,060,656	1,228,503	2,050,781
Total energy sales	9,728,573	13,437,389	13,900,479

Our energy sales in MWh to our member distribution cooperatives were 29.0% lower for 2009 as compared to 2008, primarily as a result of the departure of NOVEC. See "Member Distribution Cooperatives" above. Excluding energy sales in MWh to NOVEC in 2008, our energy sales to our member distribution cooperatives were 1.6% lower. Our energy sales in MWh to non-members were 13.7% lower. Sales to non-members consist of sales of excess purchased and generated energy.

Our demand sales in MW to our member distribution cooperatives for the past three years were as follows:

	Demand Sales Volume Year Ended December 31,		
	2009	2008	2007
		(in MW)	
Demand sales to member distribution cooperatives	16,910	24,390	24,486

Our demand sales in MW to our member distribution cooperatives were 30.7% lower for 2009 as compared to 2008, primarily as a result of the departure of NOVEC. See "Member Distribution Cooperatives" above. Excluding demand sales to NOVEC, our demand sales decreased 3.3%. This decrease is mainly due to milder weather experienced in the second, third and fourth quarters of 2009 as compared to the same periods in 2008.

Sales to Member Distribution Cooperatives

Revenues from sales to our member distribution cooperatives are a function of our formulary rate for sales of power to our member distribution cooperatives and our member distribution cooperatives' consumers' requirements for power. Our formulary rate is based on our cost of service in meeting these requirements. See "—

Factors Affecting Results—Formulary Rate." Our revenues from sales to our member distribution cooperatives by formulary rate component, energy sales to our member distribution cooperatives, and average costs to our member distribution cooperatives per MWh for the past three years were as follows:

`	Year Ended December 31,		
	2009	2008	2007
Revenues from sales to member distribution cooperatives:		(in thousands)	
Base energy revenues	$ 154,780	$ 219,713	$ 213,403
Fuel factor adjustment revenues	287,904	481,274	411,996
Total energy revenues	442,684	700,987	625,399
Demand (capacity) revenues	236,391	264,488	231,031
Total revenues from sales to member distribution cooperatives	$ 679,075	$ 965,475	$ 856,430
Average cost to member distribution cooperatives (per MWh)	$ 78.34	$ 79.08	$ 72.27

2009 Compared to 2008

Total revenues from sales to our member distribution cooperatives decreased $286.4 million, or 29.7 %, primarily as a result of the departure of NOVEC. See "Member Distribution Cooperatives" above. Excluding NOVEC's sales in 2008, total revenues from sales to member distribution cooperatives decreased approximately 2.1%. Our total energy rate (including our base energy rate and our fuel factor adjustment rate) was 11.1% lower, on a per MWh basis.

The following table summarizes the changes to our total energy rate as a result of changes to our fuel factor adjustment rate:

Effective Date of Rate Change:	% Change Increase (Decrease)
January 1, 2009	(8.2)
April 1, 2009	(3.7)
August 1, 2009	(5.7)
October 1, 2009	(8.0)

These decreases are due to the continued reduction in our realized as well as projected energy costs. Since NOVEC's departure, we are able to satisfy more of our member distribution cooperatives' energy needs through our owned generation, which generally are lower cost resources than energy we purchase to serve our member distribution cooperatives' consumers.

The capacity costs we incurred, and thus the capacity-related revenues we reflected, were 10.6% lower primarily due to decreased capacity charges. The decreased capacity charges are a function of the reduction in the amount of capacity we purchased due to the departure of NOVEC.

Our average costs per MWh to member distribution cooperatives decreased $0.74 per MWh, or 0.9%,as a result of the decrease in our total energy rate to our member distribution cooperatives.

2008 Compared to 2007

Total revenues from sales to our member distribution cooperatives increased $109.0 million, or 12.7%, primarily as a result of our higher energy rates, which facilitated the collection of previously deferred energy costs, and higher capacity costs.

Our total energy rate (including our base energy rate and our fuel factor adjustment rate) was 8.8% higher, on a per MWh basis. Due to continued increases in our energy costs and the need to collect revenues to reduce our deferred energy balance, we increased our fuel factor adjustment rate effective April 1, 2008, and again on October 1, 2008, resulting in an increase to our total energy rate of approximately 6.4% and 3.0%, respectively. In 2008, we over-collected $23.5 million of our energy costs as compared to an under-collection of $6.2 million of energy costs in 2007. The over-collection of $23.5 million in 2008 represents the collection of $21.1 million of previously deferred energy costs and an over-collection of $2.4 million of energy costs to be used to pay future energy costs. Energy sales volumes increased approximately 3.0%.

The capacity costs we incurred, and thus the capacity-related revenues we reflected, were 14.5% higher primarily due to $25.6 million in additional costs related to the implementation of RPM by PJM on June 1, 2007 and a $5.9 million decline in investment income. The purpose of RPM is to develop a longer-term pricing program for capacity resources, as well as provide localized pricing for capacity. It is designed to reduce capacity price volatility and the resulting investment risk to generators thus encouraging new investment in generation facilities. The value of capacity resources varies by location and RPM provides for the recognition of the locational value. We purchase additional capacity for capacity obligations that are not met by our owned generation resources.

Our average costs per MWh to member distribution cooperatives increased $6.81 per MWh, or 9.4%, as a result of the increase in our total energy rate and an increase in our average demand (capacity) costs to our member distribution cooperatives.

Sales to TEC

In accordance with Consolidation Accounting, TEC is considered a variable interest entity for which ODEC is the primary beneficiary. The financial statements of TEC are consolidated and the inter-company balances are eliminated in consolidation. TEC's sales to third parties are reflected as non-member revenues.

Sales to Non-Members

Sales to non-members consist of sales of excess purchased and generated energy. We primarily sell excess energy to PJM under its rates for providing energy imbalance services. Excess energy is sold at the prevailing market price at the time of sale and is the result of changes in our purchased power portfolio, differences between actual and forecasted needs, as well as changes in market conditions. Non-member revenue decreased by $41.2 million, or 54.7%, in 2009 as compared to 2008 primarily due to a decrease in the average price and a 13.7% decrease in the volume of excess energy sales.

Operating Expenses

The following is a summary of the components of our operating expenses for the past three years.

	Year Ended December 31,		
	2009	**2008**	**2007**
		(in thousands)	
Fuel	$111,863	$ 151,577	$ 158,046
Purchased power	368,270	677,341	621,630
Deferred energy	36,300	23,531	(6,177)
Operations and maintenance	48,232	38,028	43,466
Administrative and general	37,485	38,175	33,089
Depreciation, amortization and decommissioning	41,061	39,637	37,721
Amortization of regulatory asset/(liability), net	915	120	2,779
Accretion of asset retirement obligations	3,273	3,181	2,930
Taxes, other than income taxes	8,034	7,744	7,525
Total Operating Expenses	$655,433	$ 979,334	$ 901,009

Our operating expenses are comprised of the costs that we incur to generate and purchase power to meet the needs of our member distribution cooperatives, and the costs associated with any sales of power to TEC and non-members. Our energy costs generally are variable and include fuel expense as well as the energy portion of our purchased power expense. Our capacity or demand costs generally are fixed and include depreciation, amortization and decommissioning expenses, as well as the capacity portion of our purchased power expense. Additionally, all non-operating expenses and income items, including interest charges and investment income, are components of our capacity costs. See “Factors Affecting Results—Formulary Rate.”

2009 Compared to 2008

Total operating expenses decreased $323.9 million, or 33.1%, primarily due to decreases in purchased power and fuel expense partially offset by the change in deferred energy expense and an increase in operations and maintenance expense.

Purchased power expense, which includes the cost of purchased energy and capacity, decreased $309.1 million, or 45.6%, primarily due to decreased purchased power needs resulting from NOVEC’s departure as of December 31, 2008. Additionally, our average price of purchased power decreased 7.5%, reflecting declining costs in the power markets. Our owned generation resources met 48.6% of our members’ power needs in 2009 versus 36.5% in 2008.

Fuel expense decreased $39.7 million, or 26.2%, primarily due to the decrease in the dispatch of our combustion turbine facilities and the reversal of previously accrued fuel transportation costs.

Deferred energy expense changed $12.8 million, or 54.3%, reflecting a $36.3 million over-collection of energy costs in 2009 as compared to a $23.5 million over-collection of energy costs in 2008. Our deferred energy balance was a net over-collection of energy costs of $2.4 million at December 31, 2008, as compared to a net over-collection of energy costs of $38.7 million at December 31, 2009, reflecting the fact that our energy rate allowed us to collect our current year’s energy costs plus an additional $36.3 million to be used to pay future energy costs.

Operations and maintenance expense increased $10.2 million, or 26.8%, due to additional scheduled maintenance and refueling outages at our operating facilities in 2009 as compared to 2008.

2008 Compared to 2007

Total operating expenses for 2008 increased $78.3 million, or 8.7%, primarily due to increases in purchased power costs and the change in deferred energy expense.

Purchased power expense, which includes the cost of purchased energy and capacity, increased $55.7 million, or 9.0%, as a result of an 8.5% increase in the average price of purchased power. The increase in the average cost of purchased power is reflective of the timing of our forward purchases relative to the prevailing market prices at the time of those purchases. Also, on June 1, 2007, PJM implemented RPM which provides a mechanism to determine localized pricing for capacity. Additional capacity is purchased for capacity obligations that are not met by owned generation resources. During 2008, we incurred approximately $25.6 million of additional purchased power expense related to RPM.

Deferred energy expense changed $29.7 million, or 480.9%, reflecting a $23.5 million over-collection of energy costs in 2008 as compared to a $6.2 million under-collection of energy costs in 2007. Our deferred energy balance changed from a net under-collection of energy costs of $21.1 million at December 31, 2007, to a net over-collection of energy costs of $2.4 million at December 31, 2008, reflecting the fact that our energy rate allowed us to collect our under-collected deferred energy balance from the prior year as well as the current year’s energy costs plus an additional $2.4 million to be used to pay future energy costs.

Other Items

Loss on investment

During 2009, we recognized a loss of $1.4 million related to one of our auction rate securities. See “Liquidity and Capital Resources—Auction Rate Securities and Related Preferred Stock” below.

Investment Income

Investment income decreased in 2009 by $6.4 million, or 68.7%, primarily due to lower investment balances as well as lower interest rates on our investments.

Interest Charges, Net

The primary factors affecting our interest expense are scheduled payments of principal on our indebtedness, interest related to our potential liability associated with our dispute with Norfolk Southern, and capitalized interest. The major components of interest charges, net for the past three years were as follows:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Interest expense on long-term debt	$ (47,606)	$ (52,953)	$ (54,335)
Other	(831)	(5,969)	(5,842)
	(48,437)	(58,922)	(60,177)
Allowance for borrowed funds used during construction	1,127	653	241
Interest Charges, net	$ (47,310)	$ (58,269)	$ (59,936)

Interest charges, net decreased $11.0 million, or 18.8%, in 2009 as compared to 2008 primarily as a result of decreased interest expense on long-term debt due to the early retirement of a bond originally issued in connection with the Clover Unit 1 lease and decreased interest related to our settlement with Norfolk Southern. See “Liquidity and Capital Resources—Clover Leases” below.

Net Margin

Our net margin, which is a function of our total interest charges plus any additional equity contributions approved by our board of directors, decreased to $2.1 million, or 17.8% as compared to 2008 due to lower interest charges in 2009 as compared to 2008.

Financial Condition

The principal changes in our financial condition from December 31, 2008 to December 31, 2009, were caused by decreases in accrued expenses, accounts payable, lines of credit, lease deposits and obligations under long-term leases, long-term debt, accounts receivable–members, and regulatory assets, partially offset by the increase in regulatory liabilities, the change in deferred energy and an increase in nuclear decommissioning trust and fuel, materials and supplies.

- Accrued expenses decreased $58.9 million primarily related to the reduction in the liability related to the Norfolk Southern dispute.
- Accounts payable decreased $39.0 million related to decreased purchased power requirements in December 2009 as compared to December 2008.
- Lines of credit decreased $35.0 million reflecting our decreased need to borrow funds under our existing lines of credit.
- Lease deposits and obligations under long-term leases decreased $31.8 million and $30.3 million, respectively, primarily due to our acquisition of a loan and liquidation of an investment related to the lease and leaseback of our interest in Clover Unit 1 and the resulting defeasance of the loan.
- Long-term debt decreased $22.9 million due to principal payments.
- Accounts receivable–members decreased $21.2 million as a result of lower energy rates charged to our member distribution cooperatives during 2009 as well as a decrease in the extension balances.

- Regulatory assets decreased $18.2 million primarily due to the $16.2 million change in the market value of the nuclear decommissioning trust and the $2.8 million change in derivative activity.
- Regulatory liabilities increased $57.8 million primarily as a result of the establishment of a regulatory liability related to a reduction in the liability we recorded as a result of the settlement of the contract dispute with Norfolk Southern. There are two components of the regulatory liability, $55.5 million and $8.0 million. The $55.5 million will be amortized over a 54 month period beginning in December 2009 as a reduction of fuel expense. The $8.0 million has two components - $3.0 million which was amortized in December 2009 and the remaining $5.0 million which will be amortized in 2010 – both as a reduction to interest expense.
- Deferred energy changed $36.3 million due to the over-collection of energy costs during 2009.
- Nuclear decommissioning trust increased $16.2 million related to the increase in the market value of this fund.
- Fuel, materials and supplies increased $12.4 million related to an increase in coal inventory at Clover and spare parts for Clover and North Anna.

Liquidity and Capital Resources

Sources

Cash generated by our operations and periodically, borrowings under available lines of credit and our revolving credit facilities provide our sources of liquidity and capital. In the past, we have also issued long-term indebtedness in the capital markets.

Operations

Historically, our operating cash flows have generally been sufficient to meet our short- and long-term capital expenditures related to our existing generating facilities, our debt service requirements, and our ordinary business operations. In 2009 and 2007, our operating activities provided cash flows of $91.2 million and $136.8 million, respectively. In 2008, our cash needs exceeded our cash flows from operating activities by $18.7 million. Operating activities in 2009 were primarily impacted by changes in deferred energy, current liabilities, and current assets. At December 31, 2008, we had an over-collected deferred energy balance of $2.4 million as compared to an over-collected deferred energy balance of $38.7 million at December 31, 2009, which resulted in a cash inflow of $36.3 million. Current liabilities changed $26.3 million primarily due to the $39.0 million decrease in accounts payable partially offset by the $8.0 million increase in accounts payable—members. Current assets changed by $17.0 million as a result of the $12.4 million increase in fuel, materials and supplies, offset by the $21.2 million decrease in accounts receivable–members and the $12.5 million decrease in accounts receivable.

Auction Rate Securities and Related Preferred Stock

As of December 31, 2009, we had $17.3 million of principal invested in six securities, all of which were originally issued as auction rate securities and two of which have converted to preferred stock ("ARS"). The estimated fair value of our ARS was $1.8 million as of December 31, 2009. During 2009, we recognized a loss of $1.4 million related to one of these ARS which had a principal balance of $5.0 million and which we redeemed via a tender offer in December 2009 for $3.6 million. As of December 31, 2008, we had $22.3 million of principal invested in seven ARS and the estimated fair value was $9.5 million. The estimated fair value of our ARS decreased significantly from December 31, 2008, due to the deterioration of the credit ratings of the monoline insurers which insure the repayment of the ARS, and the fact that there is currently no market in which to trade these securities.

In the absence of liquidity provided by auctions, we rely on a third party to establish the estimated fair values of our ARS. It is our understanding that the estimated fair values of our ARS are determined with a valuation model that utilizes expected cash flow streams, assessments of credit quality, discount rates, and overall credit market liquidity, among other things.

The following represents changes in our ARS, principal, fair value, and unrealized loss for the years ended December 31, 2008 and 2009:

	Principal	Fair Value	Unrealized Loss [2]
ARS at December 31, 2008 [1]	$ 22,320	$ 9,467	$ 12,853
ARS at December 31, 2009 [1]	$ 17,320	$ 1,813	$ 15,507

(1) Recorded on Consolidated Balance Sheet in Investments–Unrestricted investments and other.
(2) Recorded on Consolidated Balance Sheet in Deferred Charges–Regulatory assets.

The cumulative $15.5 million difference between the principal of our ARS and the estimated fair value of our ARS (unrealized loss) was accounted for as a regulatory asset in accordance with Accounting for Regulated Operations. Future changes in the estimated fair value of our ARS will be accounted for in a similar manner.

ARS pay variable rates of interest which reset periodically in connection with the auction to purchase or sell the securities. Generally, the periodic auctions provide owners of ARS the opportunity to liquidate their investment at par value. In the event auctions are not fully subscribed, which auction agents describe as failed auctions, these securities are typically illiquid. In 2007, deteriorating conditions in the credit market resulted in seven of our ARS experiencing failed auctions. These failed auctions resulted in the interest rates on these ARS resetting at a predetermined spread above LIBOR, which, depending on the security, has ranged from 100 basis points to 200 basis points. As of March 11, 2010, all of the ARS we owned were rated between "C" and "A+" by S&P.

Clover Leases

In 1996, we entered into a lease and leaseback of our undivided interest in Clover Unit 1. In connection with this transaction, we invested a portion of the lease proceeds in a payment undertaking agreement and an investment. Distributions from the payment undertaking agreement and the investment fund a majority of our annual rent obligations under the leaseback and would fund a majority of the fixed purchase price we would need to pay if we choose to exercise the option to terminate the lease at the end of the leaseback term in 2018. The payment undertaking agreement is issued by Rabobank which has senior debt obligations that are currently rated "AAA" by S&P and "Aaa" by Moody's. The investment was insured by the Financial Guaranty Insurance Company. During 2009, the investment was liquidated and used by us to acquire the related loan which resulted in the defeasance of the loan. The investment liquidation and loan acquisition resulted in decreases to lease deposits and obligations under long-term leases of $34.0 million and $34.3 million, respectively. See "Significant Contingent Obligations—Lease of Clover Unit 1" below.

If Rabobank fails to provide funds from the payment undertaking agreement to fund rent payments under the lease, we remain liable for the payment of all rent and if we choose to exercise the option, the fixed purchase price. For 2009, distributions from the payment undertaking agreement and the investment provided $12.6 million and $1.2 million, respectively, to fund rent payments under the lease.

When we initially entered into the lease, we issued a zero-coupon bond which was pledged as collateral to the owner trust to potentially fund a portion of the fixed purchase price. The bond was insured by Ambac Assurance Corporation ("Ambac"). Under the term of the arrangements relating to the transaction, we agreed to replace this collateral if the claims paying ability of Ambac fell below "AAA" as rated by S&P and "Aaa" as rated by Moody's. In 2008, S&P and Moody's lowered their ratings of Ambac and on December 30, 2008, we replaced this collateral with $82.4 million of securities issued by the United States Treasury. This collateral replacement resulted in an increase to the lease deposits of $26.3 million and a decrease to long-term debt of $56.1 million in 2008. See "—Significant Contingent Obligations—Lease of Clover Unit 1" for additional information.

Credit Facilities

In addition to liquidity from our operating activities, we maintain a total of $365.0 million in unsecured committed lines of credit and revolving credit facilities to cover our short- and medium-term funding needs, all of which are available for general working capital purposes. At December 31, 2009, we had $27.0 million of short-term borrowings outstanding and the weighted average interest rate on these borrowings was 1.9%. See "Financial Condition." At December 31, 2008, we had a total of $340.0 million in committed lines of credit and revolving credit facilities and we had $62.0 million of short-term borrowings outstanding which had a weighted average interest rate of 1.0%. We expect that we will renew the majority of these working capital lines of credit as they expire.

Our short-term committed variable rate lines of credit are as follows:

Lender	Amount (in millions)	Expiration Date
Bank of America, N.A.	$ 70.0	September 29, 2010
Branch Banking and Trust Company	25.0	April 30, 2011
JPMorgan Chase Bank, National Association	70.0	June 3, 2010
Wachovia, National Association.	50.0	September 28, 2010
	$ 215.0	

In addition to our lines of credit, we have two committed three-year revolving credit facilities as follows:

Lender	Amount (in millions)	Expiration Date
CoBank, ACB	$ 75.0	June 18, 2010
National Rural Utilities Cooperative Finance Corp.	75.0	April 15, 2012
	$ 150.0	

Our credit agreements relating to our lines of credit and revolving credit facilities contain customary events of default, which, if they occur, would terminate our ability to borrow amounts under those facilities and potentially accelerate any outstanding loans under those facilities at the election of the lender. Some of these customary events of default relate to:

- our failure to timely pay any principal and interest due under that credit facility;
- a breach by us of our representations and warranties in the credit agreement or related documents;
- a breach of a covenant contained in the credit agreement, which, in some cases we are given an opportunity to cure and, which in certain cases includes a debt to capitalization financial covenant;
- failure to pay, when due, other indebtedness above a specified amount;
- an unsatisfied judgment above specified amounts; and
- bankruptcy events relating to us.

Financings

We fund the portion of our capital expenditures that we are not able to supply from operations through financings in the debt capital market. Since 1983, these capital expenditures have consisted primarily of the costs related to the acquisition of our interest in North Anna, our share of the costs to construct Clover, and the development and construction of our three combustion turbine facilities. We have not engaged in any material financing activities since 2003.

Uses

Our uses of liquidity and capital relate to funding our working capital needs, investment activities and financing activities. Substantially all of our investment activities relate to capital expenditures in connection with our generating facilities. We expect that cash flows from our operations, our existing lines of credit and revolving credit facilities, and potential long-term borrowings will be sufficient to meet our currently anticipated operational and capital requirements.

Capital Expenditures

We regularly forecast our capital expenditures as part of our long-term business planning activities. We review these projections frequently in order to update our calculations to reflect changes in our future plans, construction costs, market factors, and other items affecting our forecasts. Our actual capital expenditures could vary significantly from these projections. The table below summarizes our actual and projected capital expenditures, including nuclear fuel and capitalized interest, for 2007 through 2012:

	Actual Year Ended December 31,			Projected Year Ended December 31,		
	2007	2008	2009	2010	2011	2012
			(in millions)			
Combustion turbine facilities	$ 0.2	$ 0.8	$ 0.6	$ 1.2	$ 1.2	$ 1.2
Clover	1.4	2.9	10.2	7.7	17.3	7.8
North Anna	23.6	19.8	30.1	37.2	59.2	151.9
Other	1.3	3.0	1.4	27.4	1.4	1.5
Total	$ 26.5	$ 26.5	$ 42.3	$ 73.5	$ 79.1	$ 162.4

Nearly all of our capital expenditures consist of additions to electric plant and equipment. Our future capital requirements include our portion of the cost of the nuclear fuel purchased for North Anna and other capital expenditures including generation facility improvements. Projected capital expenditures for North Anna for 2010, 2011, and 2012 include $19.0 million, $38.6 million and $137.7 million related to a possible additional nuclear fuel unit at North Anna which we are currently exploring. Projected capital expenditures for "Other" includes costs related to our transmission assets, administrative and general assets, and distributed generation facilities and for 2010 include $25.9 million related to a potential base load power generation facility. We intend to use our cash from operations and borrowings to fund all of our currently projected capital requirements through 2012.

Contractual Obligations

In the normal course of business, we enter into long-term arrangements relating to the construction, operation and maintenance of our generating facilities, power purchases, the financing of our operations and other matters. See "Business—Power Supply Resources—Power Purchase Contracts" in Item 1." The following table summarizes our long-term contractual obligations at December 31, 2009:

	Payments due by Period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in millions)		
Long-term indebtedness	$ 1,050.9	$ 65.6	$ 321.9	$ 140.2	$ 523.2
Operating lease obligations	111.9	0.4	0.9	1.3	109.3
Power purchase obligations	1,641.5	200.3	325.0	247.6	868.6
Asset retirement obligations	389.4	-	-	-	389.4
Other long-term liabilities	0.3	0.1	0.2	-	-
Total	$ 3,194.0	$ 266.4	$ 648.0	$ 389.1	$1,890.5

We expect to fund these obligations with cash flow from operations and the issuances of additional long-term indebtedness.

Long-Term Indebtedness

At December 31, 2009, nearly all of our long-term indebtedness was issued under the Indenture. This indebtedness includes bonds issued to the public and bonds issued to a local governmental authority in consideration for loans to us of the proceeds of tax-exempt offerings of indebtedness by this governmental authority. Long-term indebtedness includes both the principal of and interest on long-term indebtedness, long-term indebtedness due within one year and unamortized discounts and premiums relating to long-term indebtedness.

Operating Lease Obligations

Our obligation described above primarily relates to our portion of the Clover Unit 1 purchase option price at the end of the term of the leaseback that will be satisfied by our investment in United States Treasury securities. See "Significant Contingent Obligations—Lease of Clover Unit 1."

Power Purchase Obligations

As part of our power supply strategy, we entered into a number of agreements for the purchase of capacity and energy in order to meet our member distribution cooperatives' requirements. See "Business—Power Supply Resources—Power Purchase Contracts " in Item 1. Some of these power purchase agreements contain minimum energy purchase obligations.

Asset Retirement Obligations

We account for our asset retirement obligations in accordance with Accounting for Asset Retirement and Environmental Obligations which requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. A significant portion of our asset retirement obligations relates to the future decommissioning of North Anna by 2059. See "Critical Accounting Policies—Accounting for Asset Retirement Obligations" above.

Significant Contingent Obligations

In addition to these existing contractual obligations, we have significant contingent obligations. These obligations primarily relate to our lease of our interest in Clover Unit 1, power purchase arrangements and our arrangement with TEC.

In limited circumstances, we have obligations to provide credit support if our obligations issued under the Indenture are rated below specified thresholds by S&P and Moody's. These circumstances relate to our Clover Unit 1 lease and some of our purchases of power in the market.

Lease of Clover Unit 1

In March 1996, we entered into a lease transaction relating to our 50% undivided ownership interest in Clover Unit 1 and related common facilities. In this transaction, we leased our undivided interest in the facility to an owner trust for the benefit of an investor for the full productive life of the unit in exchange for a one-time rental payment of $315.0 million at the beginning of the lease. Immediately after the lease to the owner trust, we leased the unit and common facilities back for a term of 21.8 years and agreed to make periodic rental payments to the owner trust.

We used a portion of the one-time rental payment we received to enter into a payment undertaking agreement and to purchase an investment, which provide for substantially all of:

- our periodic rent payments under the leaseback; and

- the fixed purchase price of the interest in Unit 1 at the end of the term of the leaseback if we were to exercise our option to purchase the interest of the owner trust in Unit 1 and the common facilities at that time. The fixed purchase price is $430.5 million.

After entering into the payment undertaking agreement, making the investment and paying transaction costs, we had $23.7 million remaining (the gain on the transaction) and we retained possession and our initial entitlement to the output of Unit 1.

The payment undertaking agreement was issued by Rabobank which has senior debt obligations which are currently rated "AAA" by S&P and "Aaa" by Moody's. Under this agreement, we made a payment to Rabobank, in return Rabobank agreed to make payments directly to the lender in the related lease transaction in satisfaction of a portion of our rent payment obligation under the leaseback and a portion of the fixed purchase price if we choose to exercise that option. We remain liable for all rental payments under the leaseback if Rabobank fails to make such payments, although the owner trust has agreed to pursue Rabobank before pursuing payment from us. For 2009, Rabobank paid $12.6 million of rent. At December 31, 2009, both the value of the portion of our lease obligations to be paid by Rabobank to the owner trust, as well as the value of our interest in the related payment undertaking agreement, totaled approximately $309.8 million. The investment was liquidated in 2009 and the proceeds were used by us to acquire the related loan (the "B loan").

In connection with the lease and leaseback, we also agreed to deliver a letter of credit to the investor to the lease within 90 days after our obligations under the Indenture are either rated below "A-" by S&P or "Baa2" by Moody's, or if such obligations are placed on negative credit watch by either S&P or Moody's while rated "A-" by S&P or "Baa2" by Moody's, respectively. If our ratings had been below this minimum rating at December 31, 2009, the estimated amount of the letter of credit we would have been required to provide was $30.1 million. The amount of any letter of credit we are required to deliver in connection with the lease decreases over time to zero by December 18, 2018.

At the end of the term of the Clover Unit 1 leaseback, we have the option to purchase the owner trust's interest in the unit or arrange for an acceptable third party to enter into a power purchase agreement with the owner trust. If we decide to purchase the owner trust's interest in the unit, we must pay the owner trust a fixed purchase price of $430.5 million. Payments under the payment undertaking agreement are expected to fund approximately $289.7 million of these payments. These payments also will be funded by United States Treasury securities with a maturity value of $108.6 million, and approximately $0.2 million provided by us at the closing date. The remaining $32.0 million will also be provided by us, but will in turn be paid to us as the holder of the B loan. If we do not elect to purchase the owner trust's interest in Clover Unit 1, Virginia Power has an option to purchase that interest. If Virginia Power elects to purchase the interest but fails to pay the purchase price when due, we are obligated to make that payment, with interest, within 30 days.

If we elect not to purchase the owner trust's interest in Clover Unit 1, we can arrange for a third party to purchase the owner trust's output of the unit at prices which will preserve the owner trust's net economic return as if we had purchased the related unit at the purchase option price. To be an eligible power purchaser, the third party must have, among other things, a net worth of at least $500 million and minimum specified credit ratings or other acceptable credit enhancement. We would assist in transmitting power to the third party by entering into a transmission and interconnection agreement with the owner trust. We also would be obligated to assist the owner trust in arranging new financing for the lease debt which remains outstanding at the expiration of the leaseback. We would not be obligated, however, to provide this financing. If alternate financing is not available or we otherwise fail to satisfy the conditions to arrange for a new third party purchaser, we must either exercise our purchase option or make a termination payment to the owner trust. We also must provide management services to the owner trust if power is being sold to the third party.

As a third option, at the end of the term of the leaseback, we may pay to the owner trust an amount equal to the difference between a specified termination amount and the fair market value of its interest in Unit 1 and return possession of the interest in the unit back to the owner trust. The amount we are obligated to pay cannot exceed the specified termination amount minus 20% of the fair market value of the owner trust's interest in the unit at the time the lease was entered into in 1996 or be less than the amount of the owner trust's debt to its lenders at the expiration of the leaseback. If we do not purchase the interest and the owner trust requests, we are obligated to use our best efforts to sell the owner trust's interest in the unit at the end of the leaseback. Any sale proceeds would be credited against the payment we are obligated to make to the owner trust. If we are not able to sell the interest by the end of the leaseback, we must pay the owner trust the full amount of the required payment but we are entitled to be reimbursed out of the proceeds of the sale in excess of 20% of the value of the owner trust's interest at the time the lease was entered into in 1996, plus interest, if the facility is sold within the following 36 months.

Power Purchase Arrangements

Under the terms of most of our power purchase contracts, we typically agree to provide collateral under certain circumstances and we require comparable terms from our counterparties. The collateral we may be required to post with a counterparty, and vice versa, is normally a function of the collateral thresholds we negotiate with a counterparty relative to a range of credit ratings as well as the value of our transaction(s) under a contract with a respective counterparty. At December 31, 2009 we posted $3.8 million of collateral with counterparties pursuant to the contracts we have in place. Typically, collateral thresholds under our contracts are zero once an entity is rated below investment grade by S&P or Moody's (i.e., "BBB-" or "Baa3"). At December 31, 2009, if our credit ratings fell below investment grade we estimate we would have been obligated to post approximately $87.7 million of collateral with our counterparties. This calculation is based on energy prices on December 31, 2009, and delivered power for which we have not yet paid. Depending on the difference between the price of power under our contracts and the price of power in the market at the time of the calculation, this amount could increase or decrease.

Additionally, in accordance with its credit policy, PJM subjects each applicant, participant and member of PJM to a complete credit evaluation to determine its creditworthiness, and whether it must provide any collateral to support its obligations in connection with its PJM transactions. A material change in our financial condition, including the downgrading of our credit rating by any rating agency, could cause PJM to re-evaluate our creditworthiness and require that we provide collateral. As of December 31, 2009, if PJM determined that we needed to provide collateral to support our obligations, PJM could have asked us to provide up to approximately $11.8 million of collateral.

TEC Guarantees

To facilitate the ability of TEC to sell power in the market, we have agreed to guarantee up to a maximum of $100.0 million of TEC's delivery and payment obligations associated with its energy trades if requested. See "Business—TEC" in Item 1. Our agreement to guarantee these obligations continues in effect until we elect to terminate it by providing at least 30 days prior written notice of termination or until all amounts owed to us by TEC have been paid. Our guarantee of TEC's obligations will enable it to maintain sufficient credit support to meet its delivery and payment obligations associated with its energy trades. At December 31, 2009, we had issued guarantees for up to $21.8 million of TEC's obligations and TEC had accounts payable of $0.4 million related to these guarantees.

Off-Balance Sheet Arrangements

Clover Unit 1

See "—Lease of Clover Unit 1.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The operation of our business exposes us to several common market risks, including changes in interest rates, equity prices, and market prices for power and fuel. We are exposed to market price risk by purchasing power and natural gas in the market to supply a portion of the power requirements of our member distribution cooperatives. In addition, we are exposed to a limited amount of interest rate and equity price risk.

Market Price Risk

We are exposed to market price risk by purchasing power in the market to supply the power requirements of our member distribution cooperatives in excess of our entitlement to the output of our generating facilities. See "Business—Power Supply Resources" in Item 1. In addition, the purchase of fuel to operate our generating facilities also exposes us to market price risk.

The fair value of the hedging instruments we use to mitigate market price risk is impacted by changes in market prices. At December 31, 2009, we estimate that the fair value of our purchased power agreements and forward purchases of energy and natural gas is between $1.7 billion and $1.8 billion. Approximately 50% of the fair value of this portfolio is estimable using observable market prices. The remaining 50% of the fair value of this portfolio is related to less liquid products and the fair values of these products are not directly estimable using observable market prices. In the absence of observable market prices, the valuation of the 50% of this portfolio that relates to less liquid products involves management judgment, the use of estimates, and the underlying assumptions in our portfolio model. As a result, changes in estimates and underlying assumptions or use of alternate valuation methods could affect the estimated fair value of this portfolio. As an example of our portfolio's exposure to market price risk, a 10% increase in the price of the commodities hedged by the portion of this portfolio with observable market prices is estimated to have increased the fair value of this portion of the portfolio by $90.0 million at December 31, 2009. Conversely, a 10% decrease in the price of the commodities hedged by the same portion of this portfolio is estimated to have decreased the fair value of this portion of the portfolio by $90.0 million. To the extent all or portions of our portfolio are liquidated at, above or below our original cost, these gains or losses are factored into the energy costs billed to our members pursuant to our formulary rate. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Formulary Rate" in Item 7.

Through our relationship with APM, we have formulated policies and procedures to manage the risks associated with these market price fluctuations. We use various commodity instruments, such as futures, forwards and options, to reduce our risk exposure. APM assists us in managing our market price risks by:

- maintaining a portfolio model that identifies our power producing resources (including our power purchase contract positions and generating capacity, and fuel supply, transportation and storage arrangements) and analyzing the optimal use of these resources in light of costs and market risks associated with using these resources;
- modeling our power obligations and assisting us with analyzing alternatives to meet our member distribution cooperatives' power requirements;
- selling power as our agent and the agent of TEC; and
- executing hedge trades to stabilize the cost of fuel requirements, primarily natural gas, used to operate our combustion turbine facilities and to limit our exposure under power purchase contracts with variable rates based on natural gas prices.

We also are subject to market price risk relating to purchases of fuel for North Anna and Clover. We manage these risks indirectly through our participation in the management arrangements for these facilities. Virginia Power, as operator of these facilities, has the sole authority and responsibility to procure nuclear fuel and coal for North Anna and Clover, respectively.

We understand that Virginia Power's procurement strategy for nuclear fuel includes both spot purchases and long-term contracts and is regularly reviewed by various fuel procurement personnel and Virginia Power management. Virginia Power advises us that they regularly evaluate worldwide market conditions to ensure a range of supply options at reasonable prices. See "Business—Fuel Supply—Nuclear" in Item 1.

Virginia Power has advised us they use both long-term contracts and short-term spot agreements to acquire the low sulfur bituminous coal used to fuel the Clover facility. See "Business—Fuel Supply—Coal" in Item 1.

Interest Rate Risk and Equity Price Risk

In 2009, all of our outstanding long-term indebtedness accrued interest at fixed rates.

We also have $215.0 million of committed available lines of credit and $150.0 million available under revolving credit agreements. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources." Any amounts we borrow under these facilities will accrue interest at a variable rate. At December 31, 2009, we had $27.0 million outstanding under these facilities.

We accrue decommissioning costs over the expected service life of North Anna and have made periodic deposits to a trust fund so that the fund balance will cover the estimated cost to decommission North Anna at the time of decommissioning. At December 31, 2009, $37.3 million of these funds were invested in fixed-income securities and $48.1 million of these funds were invested in equity securities. The value of these equity and fixed income securities will be impacted by changes in interest rates and price fluctuations in equity markets. To minimize adverse changes in the aggregate value of the trust fund, we actively monitor our portfolio by measuring the performance of our investments against market indexes and by maintaining and reviewing established target allocation percentages of assets in our trust to various investment options. We believe the trust fund's exposure to changes in interest rates and price fluctuations in equity markets will not have a material impact on our financial results.

Credit Risk

As of December 31, 2009, we had $17.3 million of principal invested in ARS and the estimated fair value of our ARS was $1.8 million.

ARS pay a variable rate of interest which resets periodically in connection with the auction to purchase or sell the securities. Generally, the periodic auctions provide owners of auction rate securities the opportunity to liquidate their investment at par value. In the event auctions are not fully subscribed, which auction agents describe as failed auctions, these securities are typically illiquid. In 2007 and continuing in 2008 and 2009, deteriorating conditions in the credit market resulted in seven of our ARS experiencing failed auctions. These failed auctions resulted in the interest rates on these ARS resetting at a predetermined spread to LIBOR, which, depending on the security, has ranged from 100 basis points to 200 basis points. As of March 4, 2010, all of the ARS we owned were rated between "C," and "A+" by S&P.

In the absence of liquidity provided by auctions, we rely on a third party to establish the estimated fair values of our ARS. It is our understanding that the estimated fair values of our ARS are determined with a valuation model that utilizes expected cash flow streams, assessments of credit quality, discount rates, and overall credit market liquidity, among other things.

At December 31, 2009, the $15.5 million difference between the principal of our ARS and the estimated fair value of our ARS was accounted for as a regulatory asset in accordance with Accounting for Regulated Operations. Future changes in the estimated fair value of our ARS will be accounted for in a similar manner. The estimated fair value of our ARS are included in investments – unrestricted investments and other on our Condensed Consolidated Balance Sheet and are classified as available for sale.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONSOLIDATED FINANCIAL STATEMENTS
INDEX

Report of Management on ODEC's Internal Control over Financial Reporting

Management of Old Dominion Electric Cooperative ("ODEC") has assessed ODEC's internal control over financial reporting as of December 31, 2009, based on criteria for effective internal control over financial reporting described in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that as of December 31, 2009, our system of internal control over financial reporting was properly designed and operating effectively based upon the specified criteria.

Management of ODEC is responsible for establishing and maintaining adequate internal control over financial reporting. ODEC's internal control over financial reporting is comprised of policies, procedures, and reports designed to provide reasonable assurance to ODEC's management and board of directors that the financial reporting and the preparation of the financial statements for external reporting purposes has been handled in accordance with accounting principles generally accepted in the United States. Internal control over financial reporting includes those policies and procedures that (1) govern records to accurately and fairly reflect the transactions and dispositions of assets of ODEC; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of ODEC are being made only in accordance with authorizations of the management and directors of ODEC; and (3) provide reasonable safeguards against or timely detection of material unauthorized acquisition, use or disposition of ODEC's assets.

Internal controls over financial reporting may not prevent or detect all misstatements. Accordingly, even effective internal control can provide only reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Our independent registered public accounting firm, Ernst & Young LLP, has audited our consolidated financial statements for the year ended December 31, 2009, and has issued an attestation report on our internal control over financial reporting. This attestation report is included herein.

March 17, 2010

/s/ JACKSON E. REASOR	/s/ ROBERT L. KEES
Jackson E. Reasor	Robert L. Kees
President and Chief Executive Officer	Senior Vice President and Chief Financial Officer

Report on Internal Control over Financial Reporting of Independent Registered Public Accounting Firm

To the Board of Directors
Old Dominion Electric Cooperative

We have audited Old Dominion Electric Cooperative's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Old Dominion Electric Cooperative's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management on ODEC's Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Old Dominion Electric Cooperative maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Old Dominion Electric Cooperative as of December 31, 2009 and 2008 and the related consolidated statements of revenues, expenses and patronage capital, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2009 and our report dated March 17, 2010 expressed an unqualified opinion thereon.

Ernst & Young LLP
March 17, 2010 /s/ Ernst & Young LLP

Report of Independent Registered Public Accounting Firm

To The Board of Directors
Old Dominion Electric Cooperative

We have audited the accompanying consolidated balance sheets of Old Dominion Electric Cooperative as of December 31, 2009 and 2008, and the related consolidated statements of revenues, expenses and patronage capital, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Old Dominion Electric Cooperative at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Old Dominion Electric Cooperative's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 17, 2010 expressed an unqualified opinion thereon.

Ernst & Young LLP
Richmond, Virginia

March 17, 2010 /s/ Ernst & Young LLP

OLD DOMINION ELECTRIC COOPERATIVE
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2009 AND 2008

	2009	2008
	(in thousands)	
ASSETS		
Electric Plant:		
In service	$ 1,578,459	$ 1,565,697
Less accumulated depreciation	(630,600)	(592,319)
	947,859	973,378
Nuclear fuel, at amortized cost	13,519	12,774
Construction work in progress	46,995	30,427
Net Electric Plant	1,008,373	1,016,579
Investments:		
Nuclear decommissioning trust	85,437	69,239
Lease deposits	87,052	118,826
Unrestricted investments and other	3,587	11,064
Total Investments	176,076	199,129
Current Assets:		
Cash and cash equivalents	6,278	12,025
Accounts receivable	264	7,560
Accounts receivable–deposits	3,800	5,201
Accounts receivable–members	72,716	93,888
Fuel, materials and supplies	49,290	36,852
Prepayments	3,521	3,101
Total Current Assets	135,869	158,627
Deferred Charges:		
Regulatory assets	97,864	116,073
Other	21,730	15,337
Total Deferred Charges	119,594	131,410
Total Assets	$ 1,439,912	$ 1,505,745
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 329,520	$ 319,833
Non-controlling interest	13,178	12,787
Total Patronage capital and Non-controlling interest	342,698	332,620
Long-term debt	688,736	711,675
Total Capitalization	1,031,434	1,044,295
Current Liabilities:		
Long-term debt due within one year	22,917	22,917
Lines of credit	26,954	62,000
Accounts payable	48,966	87,918
Accounts payable–members	29,004	20,921
Accrued expenses	4,659	63,589
Deferred energy	38,740	2,440
Total Current Liabilities	171,240	259,785
Deferred Credits and Other Liabilities:		
Asset retirement obligations	64,543	62,238
Obligations under long-term leases	60,612	90,954
Regulatory liabilities	96,456	38,694
Other	15,627	9,779
Total Deferred Credits and Other Liabilities	237,238	201,665
Commitments and Contingencies	-	-
Total Capitalization and Liabilities	$ 1,439,912	$ 1,505,745

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

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED STATEMENTS OF REVENUES, EXPENSES AND PATRONAGE CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 2009, 2008 AND 2007

	2009	2008	2007
		(in thousands)	
Operating Revenues	$ 713,169	$ 1,040,751	$ 963,094
Operating Expenses:			
Fuel	111,863	151,577	158,046
Purchased power	368,270	677,341	621,630
Deferred energy	36,300	23,531	(6,177)
Operations and maintenance	48,232	38,028	43,466
Administrative and general	37,485	38,175	33,089
Depreciation, amortization and decommissioning	41,061	39,637	37,721
Amortization of regulatory asset/(liability), net	915	120	2,779
Accretion of asset retirement obligations	3,273	3,181	2,930
Taxes, other than income taxes	8,034	7,744	7,525
Total Operating Expenses	655,433	979,334	901,009
Operating Margin	57,736	61,417	62,085
Other expense, net	(1,598)	(200)	(134)
Net gain on Clover Unit 2 lease transaction	-	13,121	-
Loss on investments	(1,440)	(11,480)	-
Investment income	2,931	9,377	15,272
Interest charges, net	(47,310)	(58,269)	(59,936)
Income taxes	(240)	(826)	(380)
Net Margin including Non-controlling interest	10,079	13,140	16,907
Non-controlling interest	(392)	(1,356)	(872)
Net Margin attributable to ODEC	9,687	11,784	16,035
Patronage Capital - Beginning of Year	319,833	309,112	293,077
Capital adjustment	-	(1,063)	-
Patronage Capital - End of Year	$ 329,520	$ 319,833	$ 309,112

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

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2009, 2008 AND 2007

	2009	2008	2007
		(in thousands)	
Net Margin attributable to ODEC	$ 9,687	$ 11,784	$ 16,035
Other Comprehensive Income:			
Unrealized loss on derivative contracts[1]	-	-	(435)
Other comprehensive income before non-controlling interest	9,687	11,784	15,600
Less: Non-controlling interest in comprehensive income	-	-	435
Comprehensive Income	$ 9,687	$11,784	$ 16,035

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

[1] The tax effect relates to the consolidation of the taxable entity TEC Trading, Inc.'s results of Operations. Unrealized loss on derivative contracts is net of tax benefit $0.3 million for 2007.

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED STATEMENTS OF CASH FLOW
FOR THE YEARS ENDED DECEMBER 31, 2009, 2008 AND 2007

	2009	2008	2007
		(in thousands)	
Operating Activities:			
Net Margin attributable to ODEC	$ 9,687	$ 11,784	$ 16,035
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and decommissioning	41,061	39,637	37,721
Other noncash charges	10,603	13,311	11,680
Non-controlling interest	392	1,356	872
Amortization of lease obligations	4,695	10,466	11,591
Interest on lease deposits	(3,196)	(11,827)	(11,292)
Change in current assets	17,011	(14,063)	11,232
Change in deferred energy	36,300	23,531	(6,177)
Change in current liabilities	(26,284)	(35,104)	41,679
Change in regulatory assets and liabilities	411	(8,843)	20,373
Change in deferred charges and credits	538	1,085	3,099
Contract termination fee	-	(50,000)	-
Net Cash Provided by (Used for) Operating Activities	91,218	(18,667)	136,813
Financing Activities:			
Payment of long-term debt	(22,917)	(29,667)	(22,917)
Obligations under long-term leases	(237)	(423)	(367)
Draws on lines of credit	545,367	62,000	-
Repayments on lines of credit	(580,413)	-	-
Retirement of bond, net of unamortized discount	-	(56,113)	-
Gain on Clover Unit 2 lease transaction	-	(20,121)	-
Net Cash (Used for) Financing Activities	(58,200)	(44,324)	(23,284)
Investing Activities:			
Purchases of held to maturity securities	-	(178,202)	(69,250)
Proceeds from held to maturity securities	-	118,550	46,500
Purchases of available for sale securities	-	-	(196,897)
Proceeds from sale of available for sale securities	-	-	186,079
Increase (decrease) in other investments	2,054	(2,908)	(6,680)
Electric plant additions	(42,259)	(26,524)	(26,486)
Liquidation of equity deposit	-	56,113	-
Loss on investments	1,440	11,480	-
Settlement of litigation	-	-	3,000
Acquisition of transmission assets	-	(5,306)	-
Net Cash (Used for) Investing Activities	(38,765)	(26,797)	(63,734)
Net Change in Cash and Cash Equivalents	(5,747)	(89,788)	49,795
Cash and Cash Equivalents-Beginning of Year	12,025	101,813	52,018
Cash and Cash Equivalents-End of Year	$ 6,278	$ 12,025	$ 101,813

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

OLD DOMINION ELECTRIC COOPERATIVE
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—Summary of Significant Accounting Policies

General

The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative ("ODEC" or "we" or "our") and TEC Trading, Inc. ("TEC"). In accordance with Consolidation Accounting, TEC is considered a variable interest entity for which we are the primary beneficiary. We have eliminated all intercompany balances and transactions in consolidation. The assets and liabilities and non-controlling interest of TEC are recorded at carrying value and the net assets consolidated were $13.2 million and $12.8 million at December 31, 2009, and December 31, 2008, respectively. The income taxes reported on our Statement of Revenues, Expenses and Patronage Capital relate to the tax provision for TEC. As TEC is 100% owned by our Class A members, its equity is presented as a non-controlling interest in our consolidated financial statements. Our non-controlling, 50% or less, ownership interest in other entities is recorded using the equity method of accounting.

We are a not-for-profit wholesale power supply cooperative, incorporated under the laws of the Commonwealth of Virginia in 1948. We have two classes of members. Our Class A members are customer-owned electric distribution cooperatives engaged in the retail sale of power to member consumers located in Virginia, Delaware, Maryland, and parts of West Virginia. During 2008 and 2007, we had twelve member distribution cooperatives as our Class A members. One of these entities withdrew as a member on December 31, 2008, and as of January 1, 2009, we have eleven member distribution cooperatives as Class A members. See Note 5 "Wholesale Power Contracts" for further discussion. Our sole Class B member TEC, a taxable corporation, is owned by our member distribution cooperatives. Our board of directors is composed of two representatives from each of the member distribution cooperatives and one representative from TEC. Our rates are not regulated by the respective states' public service commissions, but are set periodically by a formula that was accepted for filing by the Federal Energy Regulatory Commission ("FERC"). Our most recent filing was accepted by FERC on November 4, 2008, and became effective January 1, 2009.

We comply with the Uniform System of Accounts prescribed by FERC. In conformity with accounting principles generally accepted in the United States ("GAAP"), the accounting policies and practices applied by us in the determination of rates are also employed for financial reporting purposes.

TEC is 100% owned by ODEC's eleven member distribution cooperatives and its equity is presented as a non-controlling interest in ODEC's consolidated financial statements. We have a power sales contract with TEC, under which TEC purchases power from us that we do not need to meet the actual needs of our member distribution cooperatives and sells this power to the market under market-based rate authority granted by FERC. TEC also acquires natural gas and forward purchase contracts to hedge the price of natural gas to supply our combustion turbine facilities, and takes advantage of other power-related trading opportunities in the market which may help lower our member distribution cooperatives' costs. TEC does not engage in speculative trading.

The preparation of our consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported therein. Actual results could differ from those estimates.

Electric Plant

Electric plant is stated at original cost when first placed in service. Such cost includes contract work, direct labor and materials, allocable overhead, an allowance for borrowed funds used during construction and asset retirement costs. Upon the partial sale or retirement of plant assets, the original asset cost and current disposal costs less sale proceeds, if any, are charged or credited to accumulated depreciation. In accordance with industry practice, no profit or loss is recognized in connection with normal sales and retirements of property units.

Maintenance and repair costs are expensed as incurred. Replacements and renewals of items considered to be units of property are capitalized to the property accounts.

Depreciation

Beginning January 1, 2005, we conducted a depreciation study and updated our depreciation rates. Our next depreciation study will be completed in 2010.

Depreciation rates are as follows:

	Depreciation Rates (in percents)		
Generating Facility	**2009**	**2008**	**2007**
Clover	1.8%	1.8%	1.8%
North Anna	2.9	2.9	2.9
Louisa	3.3	3.3	3.3
Marsh Run	3.4	3.4	3.4
Rock Springs	3.5	3.5	3.5

Nuclear Fuel

Nuclear fuel is amortized on a unit of production basis sufficient to fully amortize the cost of fuel over the estimated service life and is recorded in fuel expense.

Under the Nuclear Waste Policy Act of 1982, the Department of Energy ("DOE") is required to provide for the permanent disposal of spent nuclear fuel produced by nuclear facilities, such as the North Anna Nuclear Power Station ("North Anna") in which we have an 11.6% ownership interest, in accordance with contracts executed with the DOE. However, since the DOE did not begin accepting spent fuel in 1998 as specified in its contracts, Virginia Electric and Power Company ("Virginia Power") is providing on-site spent nuclear fuel storage at the North Anna facility site. Virginia Power will continue to manage its spent nuclear fuel until the DOE begins accepting the spent nuclear fuel. In January 2004, Virginia Power filed a lawsuit seeking recovery of damages in connection with the DOE's failure to commence accepting spent nuclear fuel from North Anna and a subsequent trial held in 2008 ruled in favor of Virginia Power and the DOE filed an appeal. In March 2009, the Federal Circuit Court granted the DOE's request to stay the appeal. In November 2009, Virginia Power filed a motion to lift the stay and the DOE has opposed this motion. Once the stay is lifted, briefing on the appeal will occur.

Fuel, Materials and Supplies

Fuel, materials and supplies is comprised of spare parts for our generating assets, which are recorded at lower of cost or market, and fuel, which consists primarily of coal and No. 2 fuel oil, which is recorded at average cost.

Allowance for Borrowed Funds Used During Construction

Allowance for borrowed funds used during construction is defined as the net cost of borrowed funds used for construction purposes during the construction period and a reasonable rate on other funds when so used. We capitalize interest on borrowings for significant construction projects. Interest capitalized in 2009, 2008, and 2007, was $1.1 million, $0.7 million, and $0.2 million, respectively.

Income Taxes

As a not-for-profit electric cooperative, we are currently exempt from federal income taxation under Section 501(c)(12) of the Internal Revenue Code of 1986, as amended, and we intend to continue to operate in this manner. Based on our assessment and evaluations of relevant authority, we believe we could sustain treatment as a tax-exempt utility in the event of a challenge of our tax status. Accordingly, no provision for income taxes has been recorded based on ODEC's operations in the accompanying consolidated financial statements.

TEC is a taxable corporation and its provision for income taxes was approximately $0.2 million, $0.8, million and $0.4 million for the years ended December 31, 2009, 2008, and 2007, respectively.

Operating Revenues

Our operating revenues are derived from sales to our members and non-members. We sell energy to our Class A members pursuant to long-term wholesale power contracts that we maintain with each of our member distribution cooperatives. These wholesale power contracts obligate each member distribution cooperative to pay us for power furnished in accordance with our rates. Power furnished is determined based on month-end meter readings. For the years ended December 31, 2009, 2008, and 2007, revenue from sales to our member distribution cooperatives were $679.1 million, $965.5 million, and $856.4 million, respectively. See Note 5—Wholesale Power Contracts.

We sell excess purchased energy and excess generated energy from our combustion turbine facilities, if any, to TEC, our Class B member, under FERC market-based rate authority. Sales to TEC consisted primarily of sales of excess energy that we did not need to meet the actual needs of our member distribution cooperatives. Excess purchased energy and excess generated energy that is not sold to TEC is sold to the PJM Interconnection, LLC ("PJM") under its rates for providing energy imbalance service. TEC's sales to third parties are reflected as non-member revenues. For the years ended December 31, 2009, 2008, and 2007, energy sales to non-members were $34.1 million, $75.3 million, and $106.7 million, respectively.

Regulatory Assets and Liabilities

We account for certain revenues and expenses as a rate-regulated entity in accordance with Accounting for Regulated Operations. This allows certain revenues and expenses to be deferred at the discretion of our board of directors, pursuant to their budgetary and rate setting authority, if it is probable that such amounts will be refunded or recovered through our formulary rate in future years. Regulatory assets represent certain costs that are expected to be recovered from our member distribution cooperatives based on rate action by our board of directors in accordance with our formulary rate. Regulatory liabilities represent certain probable future reductions in revenues associated with amounts that are to be refunded to our member distribution cooperatives based on rate action by our board of directors in accordance with our formulary rate. Certain regulatory assets are included in deferred charges. Certain regulatory liabilities are included in deferred credits and other liabilities. Deferred energy, which can be either a regulatory asset or a regulatory liability, is included in current assets or current liabilities. See—Deferred Energy below. The regulatory assets and liabilities will be recognized as expenses or as a reduction in expenses, concurrent with their recovery through rates.

Debt Issuance Costs

Capitalized costs associated with the issuance of debt totaled $9.2 million and $9.9 million, at December 31, 2009 and 2008, respectively and are included in deferred charges–other. These costs are being amortized using the effective interest method over the life of the respective debt issues, and are included in interest charges, net.

Deferred Credits and Other Liabilities—Other

Deferred credits and other liabilities–other, includes gains on long-term lease transactions (see Note 6—Long-Term Lease Transactions), DOE decontamination and decommissioning liability, and liabilities associated with benefit plans for certain executives. Gains on long-term lease transactions totaled $8.7 million and $9.7 million at December 31, 2009 and 2008, respectively. These gains are being amortized into income ratably over the terms of the operating leases as a reduction to depreciation, amortization and decommissioning expense. In December 2008, we terminated the lease on Unit 2 of the Clover Power Station ("Clover") which resulted in recognition of a $20.1 million gain.

Deferred Energy

We use the deferral method of accounting to recognize differences between our energy expenses and our energy revenues collected from our member distribution cooperatives. Our deferred energy balance represents the net accumulation of any under- or over-collection of energy costs. At December 31, 2009, and 2008, we had an over-collected deferred energy balance of $38.7 million and $2.4 million, respectively. Over-collected deferred energy balances are refunded to our members in subsequent periods.

Financial Instruments (including Derivatives)

Financial instruments included in the nuclear decommissioning trust are classified as available for sale, and accordingly, are carried at fair value. Unrealized gains and losses on investments held in the nuclear decommissioning trust are deferred as a regulatory liability or a regulatory asset until realized.

Our investments in marketable securities, which are actively managed, are classified as available for sale and are recorded at fair value. Unrealized gains or losses on these investments, if material, are reflected as a component of other comprehensive income. Unrealized losses on our auction rate security investments and preferred stock ("ARS") are deferred as a regulatory asset until realized. Investments in debt securities that we have the positive intent and ability to hold to maturity are classified as held to maturity and are recorded at amortized cost. Other investments are recorded at cost, which approximates market value. See Note 7—Investments.

We primarily purchase power under both long-term and short-term physically-delivered forward contracts to supply power to our member distribution cooperatives. These forward purchase contracts meet the accounting definition of a derivative; however, a majority of the forward purchase derivative contracts qualify for the normal purchases/normal sales exception provided for under Accounting for Derivatives and Hedging. As a result, these contracts are not recorded at fair value. We record purchased power expense when the power under the forward contract is delivered.

We also purchase natural gas futures generally for three years or less to hedge the price of natural gas for the operation of our combustion turbine facilities and for use as a basis in determining the price of power in certain forward power purchase agreements. These derivatives do not qualify for the normal purchases/normal sales exception. For all derivative contracts that do not qualify for the normal purchases/normal sales accounting exception, we may elect cash flow hedge accounting in accordance with Accounting for Derivatives and Hedging. Accordingly, gains and losses on derivative contracts are deferred into Other Comprehensive Income until the hedged underlying transaction occurs or is no longer likely to occur. For derivative contracts where hedge accounting is not utilized, or for which ineffectiveness exists, we defer all remaining gains and losses on a net basis as a regulatory asset or liability in accordance with Accounting for Regulated Operations. These amounts are subsequently reclassified as purchased power or fuel expense in our Consolidated Statements of Revenues, Expenses, and Patronage Capital as the power or fuel is delivered and/or the contract settles.

Generally, derivatives are reported on the Consolidated Balance Sheet at fair value. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including broker quotes and industry publications. For individual contracts, the use of differing assumptions could have a material effect on the contract's estimated fair value.

There was no hedge ineffectiveness during the years ended December 31, 2009, 2008 or 2007.

Patronage Capital

We are organized and operate as a cooperative. Patronage capital represents our retained net margins, which have been allocated to our members based upon their respective power purchases in accordance with our bylaws. Any distributions are subject to the discretion of our board of directors and the restrictions contained in the Indenture of Mortgage and Deed of Trust, dated as of May 1, 1992, between ODEC and Crestar Bank (predecessor to U.S. Bank National Association), as trustee (the "Indenture").

Concentrations of Credit Risk

Financial instruments that potentially subject us to concentrations of credit risk consist of cash equivalents, investments, derivatives, and receivables arising from sales to our members and non-members. We place our cash investments with high credit quality financial institutions and invest in debt securities with high credit standards. Concentrations of credit risk with respect to receivables arising from sales to our member distribution cooperatives as reflected by accounts receivable–members were $72.7 million and $93.9 million, at December 31, 2009 and 2008, respectively.

Cash Equivalents

For purposes of our Consolidated Statements of Cash Flow, we consider all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Fair Value Measurements

We adopted the provision of Accounting for Fair Value Measurements and Disclosures on January 1, 2008. Accounting for Fair Value Measurements and Disclosures clarifies that the term fair value is intended to mean a market-based measure, not an entity-specific measure and gives the highest priority to quoted prices in active markets in determining fair value. It also requires disclosures about the extent to which companies measure financial assets and liabilities at fair value, the methods and assumptions used to measure fair value, and the effect of fair value measures on earnings.

We utilize the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value, into three broad levels:

- Level 1—Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as the majority of exchange-traded derivatives and listed equities and Treasury securities held in nuclear decommissioning trust funds.
- Level 2—Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 primarily include non-exchange traded derivatives such as over-the-counter commodity forwards and swaps, interest rate swaps, foreign currency forwards and options, and municipal bonds and short-term debt securities held in nuclear decommissioning trust funds.
- Level 3—Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 consist of long-dated commodity derivatives, FTRs, and other modeled commodity derivatives.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

The following table summarizes our financial assets and liabilities measured at fair value on a recurring basis (at least annually) as of December 31, 2009:

	December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(in thousands)		
Nuclear decommissioning trust [(a)]	$ 85,437	$ 85,437	$ -	$ -
Unrestricted investments and other [(b)]	1,813	-	-	1,813
Total Financial Assets	$ 87,250	$ 85,437	$ -	$ 1,813
Derivatives [(c)]	$ 6,904	$ 6,152	$ 752	$ -
Total Financial Liabilities	$ 6,904	$ 6,152	$ 752	$ -

[(a)]For additional information about our nuclear decommissioning trust see Note 7—Investments.

[(b)]Unrestricted investments and other includes investments that were available for sale. As of December 31, 2009, we had $17.3 million of principal invested in six ARS. As of December 31, 2009, we have an unrealized loss of $15.5 million related to these ARS which is recorded as a regulatory asset in accordance with Accounting for Regulated Operations. For additional information, see Note 7—Investments and Note 8—Regulatory Assets and Liabilities.

[(c)]Derivatives represent natural gas futures contracts and purchased power contracts. For additional information about our derivative financial instruments, see—Financial Instruments (including Derivatives) above and Note 4—Power Purchase Agreements.

The following table presents the net change in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category for the year ended December 31, 2009:

	2009
	(in thousands)
Balance at January 1, 2009	$ 9,467
Total realized and unrealized (losses):	
Included in earnings	(1,440)
Included in regulatory and other assets/liabilities	(2,654)
Purchases, issuances and settlements	(3,560)
Transfers out of Level 3	-
Balance at December 31, 2009	$ 1,813

The realized losses included in earnings in the Level 3 fair value category, were reported as loss on investments in our Consolidated Statement of Revenues, Expenses and Patronage Capital for the year ended December 31, 2009. The unrealized loss was reported in Regulatory Assets in our Consolidated Balance Sheet as of December 31, 2009.

New Accounting Pronouncements

We adopted the following new accounting pronouncements in January 2009:

Consolidation Accounting:

In December 2007, the Financial Accounting Standards Board ("FASB") issued additional guidance on Consolidation Accounting and the presentation of the non-controlling interest in our financial statements is presented as a component of equity in accordance with the requirements of this guidance.

Derivatives and Hedging:

In March 2008, the FASB issued additional guidance on Derivatives and Hedging which seeks to improve financial reporting for derivative instruments and hedging activities by requiring enhanced disclosures regarding the impact on financial position, financial performance, and cash flows. To achieve this increased transparency, the additional guidance requires (a) the disclosure of the fair value of derivative instruments and gains and losses in a tabular format; (b) the disclosure of derivative features that are credit risk-related; and (c) cross-referencing within the footnotes.

We are exposed to market purchases of power and natural gas to meet the power supply needs of our member distribution cooperatives that are not met by our owned generation. To manage this exposure, we utilize derivative contracts. See Financial Instruments (including Derivatives) above.

Changes in the fair value of our derivative instruments are recorded as a regulatory asset or regulatory liability. The change in these accounts is included in the operating section of our statement of cash flows.

As of December 31, 2009, excluding contracts accounted for as normal purchase/normal sale, we had the following outstanding natural gas futures contracts and purchased power contracts:

Commodity	Unit of Measure	Quantity
Natural gas	MMBTU	4,910,000
Purchased power	MWh	108,935

As of December 31, 2009, the fair value of our derivative instruments, excluding contracts accounted for as normal purchase/normal sale, was as follows:

Fair Value of Derivative Instruments

	Derivatives as of December 31, 2009	
	Balance Sheet Location	**Fair Value**
		(in thousands)
Derivatives designated as hedging instruments		
Natural gas futures contracts	Deferred credits and other liabilities-other	$ 6,152
Purchased power contracts	Deferred credits and other liabilities-other	752
Total derivatives designated as hedging instruments		$ 6,904

The Effect of Derivative Instruments on the Statement of Revenues, Expenses and Patronage Capital for the Year Ended December 31, 2009

Derivatives Accounted for Utilizing Regulatory Accounting	Amount of Gain (Loss) Recognized within Regulatory Asset/Liability for Derivatives as of December 31, 2009	Location of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income	Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Year Ended December 31, 2009
	(in thousands)		(in thousands)
Natural gas futures contracts	$(6,152)	Purchased power	$(13,946)
Purchased power contracts	(752)	Fuel	(9,792)
Total	$(6,904)		$(23,738)

Credit-risk related contingent features:

We use hedging instruments, including forwards, futures, financial transmission rights, and options, to manage our power market price risks. Because we rely substantially on the purchase of energy from other power suppliers, we are exposed to the risk that counterparties will default in performance of their obligations to us. Although we assess the creditworthiness of counterparties and other credit issues related to these purchases, and we may require our counterparties to post collateral with us, defaults may still occur. Defaults may take the form of failure to physically deliver the purchased energy or failure to pay. If this occurs, we may be forced to enter into alternative contractual arrangements or purchase energy in the forward, short-term or spot markets at then-current market prices that may exceed the prices previously agreed upon with the defaulting counterparty.

Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles:

In June 2009, the FASB issued "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles, a replacement of FASB Statement No. 162" (the "Codification"). The Codification, which was launched on July 1, 2009, became the single source of authoritative nongovernmental U.S. GAAP, superseding existing FASB, American Institute of Certified Public Accountants (AICPA), Emerging Issues Task Force (EITF) and related literature. The Codification eliminates the GAAP hierarchy contained in previously issued guidance and establishes one level of authoritative GAAP. All other literature is considered non-authoritative. This statement is effective for financial statements issued for interim and annual periods ending after September 15, 2009.

Northern Virginia Electric Cooperative

On August 15, 2008, we entered into a settlement, release and withdrawal agreement (the "Withdrawal Agreement") with Northern Virginia Electric Cooperative ("NOVEC") to end our power supply arrangement and to resolve all of our outstanding disputes. The Withdrawal Agreement resulted in the termination of NOVEC's wholesale power contract with ODEC and the withdrawal of NOVEC as a member of ODEC effective as of December 31, 2008. To satisfy the terms of the Withdrawal Agreement, we made a payment of $50.0 million to NOVEC on that date. A valuation was performed to determine the allocation of the $50.0 million settlement payment and the allocation is as follows: NOVEC contract termination fee of $48.9 million and NOVEC patronage capital adjustment of $1.1 million. The NOVEC contract termination fee was established as a regulatory asset which will be amortized from January 1, 2009 through December 31, 2028, the remaining original term of the NOVEC wholesale power contract, in equal annual amounts of $2.4 million.

Reclassifications

Certain reclassifications have been made to the prior years' consolidated financial statements to conform to the current year's presentation.

NOTE 2—Electric Plant

Our net electric plant is comprised of the following for 2009:

	Clover	North Anna	Combustion Turbine Facilities	Other	Total
			(in thousands)		
Electric plant in service	$ 668,478	$ 295,614	$ 580,014	$ 34,353	$ 1,578,459
Accumulated depreciation	(331,617)	(161,260)	(120,527)	(17,196)	(630,600)
Nuclear fuel	-	51,371	-	-	51,371
Accumulated amortization of nuclear fuel	-	(37,852)	-	-	(37,852)
Construction work in progress	992	45,957	-	46	46,995
	$ 337,853	$ 193,830	$ 459,487	$ 17,203	$ 1,008,373

Our net electric plant is comprised of the following for 2008:

	Clover	North Anna	Combustion Turbine Facilities	Other	Total
			(in thousands)		
Electric plant in service	$ 659,176	$ 294,658	$ 579,352	$ 32,511	$ 1,565,697
Accumulated depreciation	(321,126)	(154,315)	(100,795)	(16,083)	(592,319)
Nuclear fuel	-	52,149	-	-	52,149
Accumulated amortization of nuclear fuel	-	(39,375)	-	-	(39,375)
Construction work in progress	1,634	27,435	85	1,273	30,427
	$ 339,684	$ 180,552	$ 478,642	$ 17,701	$ 1,016,579

We hold a 50% undivided ownership interest in Clover, a two-unit, 860 MW (net capacity entitlement) coal-fired electric generating facility operated by Virginia Power. We are responsible for 50% of all post-construction additions and operating costs associated with Clover, as well as a pro-rata portion of Virginia Power's administrative and general expenses for Clover, and we must fund these items. Our portion of assets, liabilities, and operating expenses associated with Clover are included in our consolidated financial statements. At December 31, 2009 and 2008, we had an outstanding accounts payable balance of $7.1 million and $18.9 million, respectively, due to Virginia Power for operation, maintenance, and capital investment at Clover.

We have an 11.6% undivided ownership interest in North Anna, a two-unit, 1,842 MW (net capacity entitlement) nuclear power facility, as well as nuclear fuel and common facilities at the power station, and a portion of spare parts inventory, and other support facilities. North Anna is operated by Virginia Power, which owns the balance of the plant. We are responsible for 11.6% of all post acquisition date additions and operating costs associated with the plant, as well as a pro-rata portion of Virginia Power's administrative and general expenses for North Anna, and we must fund these items. Our portion of assets, liabilities, and operating expenses associated with North Anna are included in our consolidated financial statements. At December 31, 2009 and 2008, we had an outstanding accounts payable balance due to Virginia Power for the operation, maintenance, and capital investment at the North Anna facility of $6.6 million and $3.3 million, respectively.

In 2007, we filed a joint application with Virginia Power at the Nuclear Regulatory Commission ("NRC") for a license to construct and operate a new reactor at North Anna. We expect the application review to take at least three years. We will continue to further evaluate the project and make a final determination as to our future involvement.

We own three combustion turbine facilities that are carried at cost, less accumulated depreciation. We also own distributed generation facilities, which are included in "Other" in the net electric plant table. Additionally, we own approximately 100 miles of transmission lines on the Virginia portion of the Delmarva Peninsula, as well as two 1,100 foot 500 kilovolt ("kV") transmission lines and a 500kV substation at our combustion turbine site in Maryland. These assets are also included in "Other".

The table below summarizes our projected capital expenditures, including nuclear fuel and capitalized interest, for 2010 through 2012:

	Projected Year Ended December 31,		
	2010	**2011**	**2012**
	(in millions)		
Combustion turbine facilities	$ 1.2	$ 1.2	$ 1.2
Clover	7.7	17.3	7.8
North Anna	37.2	59.2	151.9
Other	27.4	1.4	1.5
Total	$ 73.5	$ 79.1	$ 162.4

Nearly all of our capital expenditures consist of additions to electric plant and equipment. Our future capital requirements include our portion of the cost of the nuclear fuel purchased for North Anna and other capital expenditures including generation facility improvements. Projected capital expenditures for North Anna for 2010, 2011, and 2012 include $19.0 million, $38.6 million and $137.7 million related to a possible additional nuclear fuel unit at North Anna which we are currently exploring. Projected capital expenditures for "Other" include costs related to our transmission assets, administrative and general assets, and distributed generation facilities and for 2010 include $25.9 million related to a possible base load power generation facility.

NOTE 3— Accounting for Asset Retirement Obligations

We account for our asset retirement obligations in accordance with Accounting for Asset Retirement and Environmental Obligations. This requires that legal obligations associated with the retirement of long-lived assets be recognized at fair value when incurred and capitalized as part of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized asset is depreciated over the useful life of the long-lived asset.

In the absence of quoted market prices, we determine fair value by using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit adjusted risk free rate. Our estimated liability could change significantly if actual costs vary from assumptions or if governmental regulations change significantly.

A significant portion of our asset retirement obligations relate to our share of the future decommissioning of North Anna. At December 31, 2009 and 2008, North Anna's nuclear decommissioning asset retirement obligation totaled $59.0 million and $57.0 million, respectively. Approximately every four years, a new decommissioning study for North Anna is performed. In 2009, we received the new study and adopted it effective July 1, 2009, which resulted in an additional layer related to the asset retirement obligation associated with North Anna. The additional layer resulted in a decrease to our asset retirement cost and our asset retirement obligation of $1.0 million.

The following represents changes in our asset retirement obligations for the years ended December 31, 2009 and 2008 (in thousands):

Asset retirement obligations at December 31, 2007	$ 58,742
Accretion expense	3,181
Additional asset retirement obligations	1,941
Asset retirement obligations settled	(1,626)
Asset retirement obligations at December 31, 2008	$ 62,238
Accretion expense	3,273
Reduction in asset retirement obligations – new layer	(968)
Asset retirement obligations at December 31, 2009	$ 64,543

The cash flow estimates for North Anna's asset retirement obligations were based upon the 20-year life extension which was granted in 2003. Given the life extension, the level of the nuclear decommissioning trust currently appears to be adequate to fund North Anna's asset retirement obligations and no additional funding is currently required. Therefore, with the approval by FERC, we ceased collection of decommissioning expense in August 2003. As we are not currently collecting decommissioning expense in our rates, we are deferring the difference between the earnings on the nuclear decommissioning trust and the total asset retirement obligation related depreciation and accretion expense for North Anna as part of our asset retirement obligation regulatory liability. See Note 8—Regulatory Assets and Liabilities.

NOTE 4—Power Purchase Agreements

In 2009, 2008, and 2007, our owned generating facilities together furnished approximately 48.6%, 36.5%, and 39.3%, respectively, of our energy requirements. The remaining needs were satisfied through physically-delivered forward purchase power contracts and spot market purchases.

We purchase significant amounts of power in the market through long-term and short-term physically-delivered forward power purchase contracts. We also purchase power in the spot market. This approach to meeting our member distribution cooperatives' energy requirements is not without risks. To mitigate these risks, we attempt to match our energy purchases with our energy needs to reduce our spot market purchases of energy. Additionally, we utilize policies and procedures to manage the risks in the changing business environment. These policies and procedures, developed in cooperation with Aces Power Marketing LLC ("APM"), are designed to strike an appropriate balance between minimizing costs and reducing energy cost volatility. At December 31, 2009, due to changes in energy prices, we were required to post $3.8 million with our counterparties in accordance with the terms of our respective master power purchase and sales agreements with them.

We have contractual arrangements with Virginia Power, the operator and co-owner of Clover and North Anna, which permit us to purchase reserve capacity and energy. We intend to purchase our reserve capacity requirements for Clover and North Anna from Virginia Power under these arrangements until either the date on which all facilities at North Anna have been retired or decommissioned, or the date we have no interest in North Anna, whichever is earlier.

In October 2009, we signed a long-term power purchase and sale agreement with Exelon Generation ("Exelon") in connection with our request for power supply proposal process. Under the terms of this agreement, Exelon will begin supplying 200 MW of energy and capacity to us for ten years beginning in June 2010.

Our purchased power costs for 2009, 2008, and 2007 were $368.3 million, $677.3 million, and $621.6 million, respectively.

Our power purchase agreements contain certain minimum energy requirements. As of December 31, 2009, our minimum purchase commitments under the various agreements, without regard to capacity reductions or cost adjustments, were as follows:

Year Ending December 31,	Minimum Energy Requirements
	(in millions)
2010	$ 188.3
2011	174.8
2012	128.5
	$ 491.6

NOTE 5—Wholesale Power Contracts

We began 2009 with eleven member distribution cooperatives and each had a wholesale power contract with us. On December 31, 2008, NOVEC terminated their wholesale power contract with us and withdrew as a member. See Note 1—Summary of Significant Accounting Policies—NOVEC.

We currently have a wholesale power contract with each of our eleven member distribution cooperatives. The wholesale power contracts are "all-requirements" contracts. Each contract obligates us to sell and deliver to the member distribution cooperative, and obligates the member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions, to the extent that we have the power and facilities available to do so. These contracts were amended and restated in 2008, effective January 1 2009, and extend until January 1, 2054 and beyond this date unless either party gives the other at least three years notice of termination.

The two principal exceptions to the all-requirements obligations of the member distribution cooperatives relate to the ability of our mainland Virginia member distribution cooperatives to purchase hydroelectric power allocated to them from the Southeastern Power Administration, and the ability of all member distribution cooperatives to purchase energy from specified qualifying facilities under the Public Utility Regulatory Policies Act or similar laws. Purchases under these exceptions constituted less than 3.0 % of our member distribution cooperatives' total capacity and energy requirements in 2009.

Two additional limited exceptions to the all-requirements nature of the contract permit the member distribution cooperatives to receive up to the greater of five percent of their power requirements or five megawatts from owned generation or other suppliers and to purchase additional power from other suppliers in limited circumstances following approval by our board of directors. Currently, none of our member distribution cooperatives have received any of their power requirements under these exceptions.

Each member distribution cooperative is required to pay us monthly for power furnished under its wholesale power contract in accordance with our formulary rate. The formulary rate, which has been filed with and accepted by FERC, is designed to recover our total cost of service and create a firm equity base. More specifically, the formulary rate is intended to meet all of our costs, expenses and financial obligations associated with our ownership, operation, maintenance, repair, replacement, improvement, modification, retirement and decommissioning of our generating plants, transmission system or related facilities, services provided to the member distribution cooperatives, and the acquisition and transmission of power or related services, including:

- payments of principal and premium, if any, and interest on all indebtedness issued by us (other than payments resulting from the acceleration of the maturity of the indebtedness);
- any additional cost or expense, imposed or permitted by any regulatory agency; and
- additional amounts required to meet the requirement of any rate covenant with respect to coverage of principal and interest on our indebtedness contained in any indenture or contract with holders of our indebtedness.

The rates established under the wholesale power contracts are designed to enable us to comply with financing, regulatory and governmental requirements, which apply to us from time to time.

The formulary rate allows us to recover and refund amounts under our Margin Stabilization Plan. The Margin Stabilization Plan allows us to review our actual capacity-related cost of service and capacity revenues and adjust revenues from our member distribution cooperatives to meet our financial coverage requirements and accumulate additional equity as approved by our board of directors. We record all adjustments, whether increases or decreases, in the year affected and allocate any adjustments to our member distribution cooperatives based on power sales during that year. We collect these increases from our member distribution cooperatives, or offset decreases against amounts owed by our member distribution cooperatives to us, generally in the succeeding calendar year. Each quarter we adjust revenues and accounts payable—members or accounts receivable—members, as appropriate, to reflect these adjustments. In 2009, 2008, and 2007, under our Margin Stabilization Plan, we reduced operating revenues by $2.4 million, $11.3 million, and $30.5 million, respectively, and increased accounts payable—members by the same amount. In 2007, our board of directors approved an additional equity contribution of $4.0 million that was collected during 2007 in accordance with our wholesale power contracts and our formulary rate.

Revenues from the following member distribution cooperatives for the past three years were as follows:

	Year Ended December 31,		
	2009	2008	2007
	(in millions)		
Rappahannock Electric Cooperative	$191.4	$ 201.4	$ 184.4
Delaware Electric Cooperative, Inc.	101.5	100.1	93.7
Choptank Electric Cooperative, Inc.	80.2	80.6	76.2
Southside Electric Cooperative	70.6	72.3	66.8
Shenandoah Valley Electric Cooperative	64.5	66.3	59.9
A&N Electric Cooperative (1)	53.3	52.9	17.3
Mecklenburg Electric Cooperative	43.4	44.2	39.9
Prince George Electric Cooperative	23.7	24.3	22.4
Northern Neck Electric Cooperative	21.7	21.6	20.4
Community Electric Cooperative	15.8	15.8	14.4
BARC Electric Cooperative	13.0	13.9	12.9
NOVEC (2)	-	272.1	248.1
	$ 679.1	$ 965.5	$ 856.4

(1) A&N Electric Cooperative acquired additional service territory in 2008.
(2) NOVEC ceased to be a member of ODEC effective December 31, 2008.

NOTE 6—Long-term Lease Transactions

Clover Unit 1

On March 1, 1996, we entered into a long-term lease transaction with an owner trust for the benefit of an investor. Under the terms of the transaction, we entered into a 48.8 year lease of our interest in Clover Unit 1, valued at $315.0 million, to such owner trust, and immediately after we entered into a 21.8 year lease of the interest back from such owner trust. As a result of the transaction, we recorded a deferred gain of $23.7 million, which is being amortized into income ratably over the 21.8 year operating lease term, as a reduction to operating expenses. At December 31, 2009, and December 31, 2008, the unamortized portion of the deferred gain was $8.7 million and $9.7 million.

We used a portion of the one-time rental payment of $315.0 million we received to enter into a payment undertaking agreement and to purchase an investment that would provide for substantially all of our periodic rent payments under the leaseback, and the fixed purchase price of the interest in the unit at the end of the term of the leaseback if we were to exercise our option to purchase the interest of the owner trust in the unit at that time. The payment undertaking agreement, which had a balance of $309.8 million at December 31, 2009, is issued by Cooperative Centrale Raiffeisen Boerenleenbank B.A., "Rabobank Nederland", which has senior debt obligations which are currently rated "AAA" by S&P and "Aaa" by Moody's. The amount of debt considered to be extinguished by in substance defeasance was $309.8 million and $308.3 million, at December 31, 2009 and December 31, 2008, respectively.

The investment was insured by the Financial Guaranty Insurance Company. During 2009, the investment was liquidated and used by us to acquire the related loan which resulted in the defeasance of the loan. The investment liquidation and loan acquisition resulted in decreases to lease deposits and obligations under long-term leases of $34.0 million and $34.3 million, respectively.

At the end of the term of the Unit 1 leaseback, we have three options: (1) retain possession of the interest in the unit by paying a fixed purchase price to the owner trust, (2) return possession of the interest to the owner trust and arrange for an acceptable third party to enter into a power purchase agreement with the owner trust, or (3) return possession of the interest and pay a termination amount to the owner trust.

When we initially entered into the lease, we issued a zero-coupon bond which was pledged as collateral to the owner trust to potentially fund a portion of the fixed purchase price. The bond was insured by Ambac Assurance Corporation ("Ambac"). Under the term of the arrangements relating to the transaction, we agreed to replace this collateral if the claims paying ability of Ambac fell below "AAA" as rated by S&P and "Aaa" as rated by Moody's. In 2008, S&P and Moody's lowered their ratings of Ambac and on December 30, 2008, we replaced this collateral with $82.4 million of securities issued by the United States Treasury. This collateral replacement resulted in an increase to the lease deposits of $26.3 million and a decrease to long-term debt of $56.1 million. At December 31, 2009, the book value of these Unites States Treasury securities totaled $87.1 million.

Clover Unit 2

On July 31, 1996, we entered into a long-term lease transaction with an owner trust created for the benefit of another investor. Under the terms of the transaction, we entered into a 63.4 year lease of our interest in Clover Unit 2, valued at $320.0 million, to such owner trust and immediately after we entered into a 23.4 year lease of the interest back from such owner trust. As a result of the transaction, we recorded a deferred gain of $39.3 million, which was to be amortized into income ratably over the 23.4 year operating lease term, as a reduction to operating expenses. On December 19, 2008, we terminated the lease and leaseback of our interest in Clover Unit 2. In connection with the termination, we provided for a termination payment of $7.0 million to the investor in the lease, the assignment of various pledged securities and invested monies, and the payment of reasonable and documented fees incurred by the owner trust and the other parties to the termination. ODEC was released of all liabilities related to the Clover Unit 2 lease and leaseback transaction and we continue to retain possession of, and entitlement to the output of Clover Unit 2. This termination resulted in a decrease to lease deposits and a decrease to obligations under long-term leases of $99.7 million and $99.8 million, respectively. Due to the termination during 2008 of the Clover Unit 2 lease, the unamortized portion of the deferred gain, $20.1 million, was recognized into income and the $7.0 million termination payment was expensed for a net gain of $13.1 million.

NOTE 7—Investments

Investments were as follows at December 31, 2009 and 2008:

Description	Designation	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
				(in thousands)		
December 31, 2009						
Nuclear decommissioning trust (1)						
Debt securities	Available for sale	$ 39,289	$ -	$ (2,020)	$ 37,269	$ 37,269
Equity securities	Available for sale	46,577	3,661	(2,142)	48,096	48,096
Cash and other	Available for sale	72	-	-	72	72
Total Nuclear Decommissioning Trust		$ 85,938	$ 3,661	$ (4,162)	$ 85,437	$ 85,437
Lease deposits (2)						
Government obligations	Held to maturity	$ 87,052	$ 138	$ (7,213)	$ 79,977	$ 87,052
Total Lease Deposits		$ 87,052	$ 138	$ (7,213)	$ 79,977	$ 87,052
Unrestricted investments (3)						
Debt securities	Available for sale	$ 1,761	$ -	$ -	$ 1,761	$ 1,761
Equity securities	Available for sale	52	-	-	52	52
Total Unrestricted Investments		$ 1,813	$ -	$ -	$ 1,813	$ 1,813
Other						
Equity securities	Available for sale	$ 62	$ -	$ (6)	$ 56	$ 56
Non-marketable equity investments	Equity	1,718	-	-	1,718	1,718
Total Other		$ 1,780	$ -	$ (6)	$ 1,774	$ 1,774
				Total Carrying Value		$ 176,076
December 31, 2008						
Nuclear decommissioning trust (1)						
Debt securities	Available for sale	$ 37,227	$ -	$ (7,345)	$ 29,882	$ 29,882
Equity securities	Available for sale	47,071	-	(7,855)	39,216	39,216
Cash and other	Available for sale	141	-	-	141	141
Total Nuclear Decommissioning Trust		$ 84,439	$ -	$ (15,200)	$ 69,239	$ 69,239
Lease deposits (2)						
Debt securities	Held to maturity	$ 34,021	$ -	$ -	$ 34,021	$ 34,021
Government obligations	Held to maturity	84,805	285	(270)	84,820	84,805
Total Lease Deposits		$ 118,826	$ 285	$ (270)	$ 118,841	$ 118,826
Unrestricted investments(4)						
Debt securities	Available for sale	$ 8,397	$ -	$ -	$ 8,397	$ 8,397
Equity securities	Held to maturity	1,070	-	-	1,070	1,070
Total Unrestricted Investments		$ 9,467	$ -	$ -	$ 9,467	$ 9,467
Other						
Equity securities	Available for sale	$ 46	$ -	$ (17)	$ 29	$ 29
Non-marketable equity investments	Equity	1,568	-	-	1,568	1,568
Total Other		$ 1,614	$ -	$ (17)	$ 1,597	$ 1,597
				Total Carrying Value		$ 199,129

(1) Investments in the nuclear decommissioning trust are restricted for the use of funding our share of the asset retirement obligations of the future decommissioning of North Anna. See Note 3 - Accounting for Asset Retirement Obligations. Realized and unrealized gains and losses related to assets held in the nuclear decommissioning trust are deferred as a regulatory asset or liability.

(2) Investments in lease deposits are restricted for the use of funding our future lease obligations. See Note 6 - Long-term Lease Transactions.

(3) The cost represents investments in ARS with a par value of $28.8 million, net of a $5.0 million par value redemption that resulted in a $1.4 million recognized loss. The cost has been written down by $27.0 million due to the $11.5 million recognition of a loss and the $15.5 million market value adjustment. We have deferred the $15.5 million as a regulatory asset in accordance with Accounting for Regulated Operations. See Note 8 - Regulatory Assets and Liabilities.

(4) The cost represents investments in ARS with a par value of $33.8 million that have been written down by $24.4 million due to the $11.5 million recognition of a loss and the $12.9 million market value adjustment. We have deferred the $12.9 million as a regulatory asset in accordance with Accounting for Regulated Operations. See Note 8 - Regulatory Assets and Liabilities

Our investments by classification at December 31, 2009 and 2008 were as follows:

Description	December 31, 2009 Cost	December 31, 2009 Carrying Value	December 31, 2008 Cost	December 31, 2008 Carrying Value
	(in thousands)			
Available for Sale	$ 87,813	$ 87,306	$ 93,953	$ 78,735
Held to Maturity	87,052	87,052	118,826	118,826
Equity	1,718	1,718	1,568	1,568
	$176,583	$176,076	$ 214,347	$ 199,129

Contractual maturities of unrestricted debt securities at December 31, 2009, were as follows:

Description	Less than 1 year	1-5 years	5-10 years	More than 10 years	Total
			(in thousands)		
Available for Sale	$ -	$ -	$ -	$ 1,761	$ 1,761
Held to Maturity	-	-	-	-	-
	$ -	$ -	$ -	$ 1,761	$ 1,761

The contractual maturities of our restricted debt securities related to our nuclear decommissioning trust have not been disclosed since all maturities are prior to the estimated decommissioning date nor have we disclosed the contractual maturities of our restricted debt securities related to our lease deposits since all maturities are concurrent with the transaction maturity date.

NOTE 8 – Regulatory Assets and Liabilities

In accordance with Accounting for Regulated Operations, we record regulatory assets and liabilities that result from our ratemaking. Our regulatory assets and liabilities at December 31, 2009 and 2008, were as follows:

	2009	2008
	(in thousands)	
Regulatory Assets:		
Unamortized losses on reacquired debt	$ 26,244	$ 28,902
Deferred asset retirement costs	430	446
North Anna nuclear decommissioning trust market value adjustment	501	15,200
Deferred net unrealized losses on derivative instruments	6,904	9,735
Deferred loss on ARS	15,507	12,853
NOVEC contract termination fee	46,490	48,937
Loan acquisition fee	1,788	-
Total Regulatory Assets	$ 97,864	$ 116,073
Regulatory Liabilities:		
North Anna asset retirement obligation deferral	$ 36,123	$ 37,783
Norfolk Southern settlement	59,488	-
Unamortized gains on reacquired debt	845	911
Total Regulatory Liabilities	$ 96,456	$ 38,694
Regulatory Liabilities included in Current Liabilities:		
Deferred energy	$ 38,740	$ 2,440

The regulatory assets will be recognized as expenses concurrent with their recovery through rates and the regulatory liabilities will be recognized as a reduction to expenses concurrent with their refund through rates.

Regulatory assets included in deferred charges are detailed as follows:

- Unamortized losses on reacquired debt are the costs we incurred to purchase our outstanding indebtedness prior to its scheduled retirement. These losses are amortized over the life of the original indebtedness and will be fully amortized in 2023.

- Deferred asset retirement costs are for the cumulative effect of change in accounting principle for the Clover and distributed generation facilities as a result of the adoption of Accounting for Asset Retirement and Environmental Obligations. These costs will be fully amortized in 2034.

- North Anna nuclear decommissioning trust market value adjustment reflects the change in the market value of the investments in the nuclear decommissioning trust.

- Deferred net unrealized losses on derivative instruments will be matched and recognized in the same period the expense is incurred for the hedged item.

- Deferred loss on ARS, all which were originally issued as auction rate securities and two of which have converted to preferred stock, reflects the write-down of the value of our ARS, which became illiquid in 2008 due to deteriorating conditions in the credit market and failed auctions. Future changes in credit market conditions will impact the estimated fair value of our ARS, and thus the amount of the deferred loss. The loss on ARS will be recognized when the ARS is sold.

- NOVEC contract termination fee reflects the amount allocated to the contract value of the payment to NOVEC in 2008 as part of the termination agreement. The wholesale power contract with NOVEC was scheduled to expire in 2028, thus the contract termination fee will be amortized ratably through 2028.

- Loan acquisition fee reflects the onetime fee we paid to the investor to facilitate the acquisition of the $33.0 million loan related to the lease of Clover Unit 1. This fee will be amortized ratably over the remaining life of the lease and will be fully amortized in 2018.

Regulatory liabilities included in deferred credits and other liabilities are detailed as follows:

- North Anna asset retirement obligation deferral is the cumulative effect of change in accounting principle as a result of the adoption of Accounting for Asset Retirement and Environmental Obligations.

- Norfolk Southern settlement reflects the difference in the amount previously accrued and the actual settlement amount. There are two components to this amount: $54.5 million will be amortized ratably through May 2014 as a reduction of fuel expense and $5.0 million will be amortized ratably through December 2010 as a reduction to interest expense.

- Unamortized gains on reacquired debt are the gains we recognized when we purchased our outstanding indebtedness prior to its scheduled retirement. These gains are amortized over the life of the original indebtedness and will be fully amortized in 2023.

Regulatory liabilities included in current liabilities for 2009 are detailed as follows:

- Deferred energy—see Note 1—Deferred Energy for our method of accounting for deferred energy.

NOTE 9—Long-term Debt

Long-term debt consists of the following:

	December 31, 2009	December 31, 2008
	(in thousands)	
$250,000,000 principal amount of 2003 Series A Bonds due 2028 at an interest rate of 5.676%	$ 197,917	$ 208,332
$27,755,000 principal amount of 2002 Series A Bonds due 2028 at an interest rate of 5.00%	27,755	27,755
$32,455,000 principal amount of 2002 Series A Bonds due 2028 at an interest rate of 5.625%	32,455	32,455
$300,000,000 principal amount of 2002 Series B Bonds due 2028 at an interest rate of 6.21%	237,500	250,000
$215,000,000 principal amount of 2001 Series A Bonds due 2011 at an interest rate of 6.25%	215,000	215,000
$120,000,000 principal amount of First Mortgage Bonds, 1993 Series A, due 2023 at an interest rate of 7.78%	1,000	1,000
	711,627	734,542
Less unamortized discounts and premiums	26	50
Less current maturities	(22,917)	(22,917)
	$ 688,736	$ 711,675

In December 2008, we replaced the collateral related to Clover Unit 1 Lease. See Note 6—Long-term Lease Transactions. The collateral replacement resulted in the retirement of the $108.6 million First Mortgage Bonds, 1996, Series B and the related unamortized discount of $52.5 million. At December 31, 2009, and December 31, 2008, deferred gains and losses on reacquired debt totaled a net loss of approximately $25.4 million and $28.0 million, respectively. Deferred gains and losses on reacquired debt are deferred under regulatory accounting. See Note 8 – Regulatory Assets and Liabilities.

Maturities of long-term debt for the next five years and thereafter are as follows:

Year Ending December 31,	(in thousands)
2010	$ 22,917
2011	237,917
2012	22,917
2013	22,917
2014	23,005
2015 and thereafter	381,954
	$ 711,627

The aggregate fair value of long-term debt was $740.1 million and $728.8 million at December 31, 2009 and 2008, respectively, based on current market prices. For debt issues that are not quoted on an exchange, interest rates currently available to us for issuance of debt with similar terms and remaining maturities are used to estimate fair value.

Substantially all of our assets are pledged as collateral under the Indenture. Under the Indenture, we may not make any distribution, including a dividend or payment or retirement of patronage capital, to our members if an event of default exists under the Indenture. Otherwise, we may make a distribution to our members if (1) after the distribution, our patronage capital as of the end of the most recent fiscal quarter would be equal to or greater than 20% of our total long-term debt and patronage capital, or (2) all of our distributions for the year in which the distribution is to be made do not exceed 5% of the patronage capital as of the end of the most recent fiscal year. For this purpose, patronage capital and total long-term debt do not include any earnings retained in any of our subsidiaries or affiliates or the debt of any of our subsidiaries or affiliates.

NOTE 10—Short-term Borrowing Arrangements

We maintain committed lines of credit and revolving credit facilities to cover short- and intermediate- term funding needs. At December 31, 2009, we had short-term committed variable rate lines of credit in the aggregate amount of $215.0 million, all of which are available for general working capital purposes. Additionally, we had two committed three-year revolving credit facilities, totaling $150.0 million, available for general corporate purposes. At December 31, 2009 and 2008, we had $27.0 million and $62.0 million, respectively, in short-term borrowings. We expect that we will renew the majority of the working capital lines of credit and revolving credit facilities as they expire.

We maintain a policy which allows our member distribution cooperatives to pre-pay or extend payment on their monthly power bills. Under this policy, we pay interest on early payment balances at a blended investment and outside short-term borrowing rate, and we charge interest on extended payment balances at a blended prepayment and outside short-term borrowing rate. Amounts advanced by our member distribution cooperatives are included in accounts payable—members and totaled $26.6 million and $9.6 million at December 31, 2009 and 2008, respectively. Amounts extended by our member distribution cooperatives are included in accounts receivable—members and totaled $10.5 million and $19.4 million at December 31, 2009 and 2008, respectively.

NOTE 11—Employee Benefits

Substantially all of our employees participate in the National Rural Electric Cooperative Association ("NRECA") Retirement Security Plan, a noncontributory, defined benefit multiple employer master pension plan. We participate in a pension restoration plan, which is intended to provide a supplemental benefit for employees who would have a reduction in their pension benefit from the Retirement Security Plan because of the Internal Revenue Code limitations. The cost of these plans is funded annually by payments to NRECA to ensure that annuities in amounts established by the plan will be available to individual participants upon their retirement. Pension expense was $1.9 million, $1.4 million, and $1.3 million for 2009, 2008, and 2007, respectively.

We have also elected to participate in a defined contribution 401(k) retirement plan administered by Diversified Investment Advisors. Under the plan, employees may elect to have up to 100% or $16,500, whichever is less, of their salary withheld on a pretax basis, subject to Internal Revenue Service limitations, and invested on their behalf. Also, a catch-up contribution is available for participants in the plan once they attain age 50. The maximum catch-up contribution for 2009 was $5,500. We match up to the first 2% of each participant's base salary. Our matching contributions were $190,000, $170,000, and $149,000, in 2009, 2008, and 2007, respectively.

NOTE 12—Insurance

As a joint owner of North Anna, we are a party to the insurance policies that Virginia Power procures to limit the risk of loss associated with a possible nuclear incident at the station, as well as policies regarding general liability and property coverage. All policies are administered by Virginia Power, which charges us for our proportionate share of the costs.

The Price-Anderson Act provides the public up to $12.5 billion of liability protection per nuclear incident via obligations required of owners of nuclear power plants. The Price-Anderson Act Amendment of 1988 allows for an inflationary provision adjustment every five years. Virginia Power has purchased $300.0 million of coverage from commercial insurance pools with the remainder provided through a mandatory industry risk-sharing program.

In the event of a nuclear incident at any licensed nuclear reactor in the United States, we, jointly with Virginia Power, could be assessed up to $118.0 million for each licensed reactor not to exceed $18.0 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. The Price-Anderson Act was first enacted in 1957 and was renewed again in 2005.

Virginia Power's current level of property insurance coverage, $2.55 billion for North Anna, exceeds the NRC minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site and includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first, to return the reactor to and maintain it in a safe and stable condition and second, to decontaminate the reactor and station site in accordance with a plan approved by the NRC. The nuclear property insurance is provided to Virginia Power and us, jointly, by Nuclear Electric Insurance Limited ("NEIL"), a mutual insurance company, and is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance company. The maximum assessment for the current policy period is $49.0 million. Based on the severity of the incident, the board of directors of the nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. We, jointly with Virginia Power, have the financial responsibility for any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination.

Virginia Power purchases insurance from NEIL to cover the cost of replacement power during the prolonged outage of a nuclear unit due to direct physical damage of the unit. Under this program, we, jointly with Virginia Power, are subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. The current policy period's maximum assessment is $19.0 million.

Our share of the contingent liability for the coverage assessments described above is a maximum of $31.2 million at December 31, 2009.

NOTE 13—Regional Headquarters, Inc.

We own 50% of Regional Headquarters, Inc. ("RHI"), which holds title to the office building that is being partially leased to us, which we account for under the equity method. We are obligated to make lease payments equal to one half of RHI's annual operating expenses, net of rental income from third party lessees, through the year 2016. During 2009, our rent expense was $0.3 million. During 2008 and 2007, our rent expense was $0.4 million.

Estimated future lease payments, without regard to changes in square footage, third party occupancy rates, operating costs, and inflation are as follows:

Year Ending December 31,	(in thousands)
2010	$ 448
2011	448
2012	448
2013	448
2014	448
2015 and thereafter	896
	$ 3,136

NOTE 14—Supplemental Cash Flows Information

Cash paid for interest in 2009, 2008, and 2007, was $46.9 million, $49.2 million, and $51.5 million, respectively.

NOTE 15—Commitments and Contingencies

Legal

Norfolk Southern

We and Virginia Power have been parties to a contract dispute with a fuel transportation supplier, Norfolk Southern Railway Company ("Norfolk Southern"), in the Circuit Court of Halifax County, Virginia. On October 30, 2009, we and Virginia Power settled our contract dispute with Norfolk Southern. Under the terms of the settlement, we and Virginia Power agreed to pay Norfolk Southern approximately $10.8 million in damages, representing underpayments made to Norfolk Southern from December 1, 2003 through the present. Our share of the settlement amount is approximately $5.4 million. A regulatory liability of $63.5 million was established for the difference between the amount previously accrued and collected and the settlement amount. Also, as part of the settlement, the parties agreed on the fourth quarter 2009 adjusted base rates, which will be adjusted on a quarterly basis under the terms of the parties' coal transportation agreement. There are two components of the regulatory liability, $55.5 million and $8.0 million. The $55.5 million will be amortized over a 54 month period beginning in December 2009 as a reduction of fuel expense. The $8.0 million has two components - $3.0 million which was amortized in December 2009 and the remaining $5.0 million which will be amortized in 2010 – both as a reduction to interest expense.

In 2008, we, along with Virginia Power, filed a separate suit against Norfolk Southern in the Circuit Court of the City of Richmond, Virginia, seeking to recover $4.9 million, plus interest, for unauthorized fuel surcharges improperly collected by Norfolk Southern under our coal transportation agreement. Our portion of this claim is $2.5 million, excluding interest. We believe that the fuel surcharge conflicts with the payment provisions specified in the agreement. The parties are currently engaged in discovery.

Environmental

We are subject to federal, state, and local laws and regulations and permits designed to both protect human health and the environment and to regulate the emission, discharge, or release of pollutants into the environment. We believe we are in material compliance with all current requirements of such environmental laws and regulations and permits. However, as with all electric utilities, the operation of our generating units could be affected by future environmental regulations. Capital expenditures and increased operating costs required to comply with any future regulations could be significant.

Our direct capital expenditures for environmental control equipment at our generating facilities, excluding capitalized interest, were immaterial in 2009.

Insurance

Under several of the nuclear insurance policies procured by Virginia Power to which we are a party, we are subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance companies. See Note 12—Insurance.

NOTE 16—Selected Quarterly Financial Data (Unaudited)

A summary of the quarterly results of operations for the years 2009 and 2008 follow. Amounts reflect all adjustments, consisting of only normal recurring accruals, necessary in the opinion of management for a fair statement of the results for the interim periods. Results for the interim periods may fluctuate as a result of weather conditions, changes in rates and other factors.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			(in thousands)		
Statement of Operations Data					
2009					
Operating Revenue	$ 202,722	$ 168,938	$ 182,952	$ 158,557	$ 713,169
Operating Margin	15,581	15,278	15,367	11,510	57,736
Net Margin	2,571	2,583	2,626	1,907	9,687
2008					
Operating Revenue	$ 259,235	$ 239,141	$ 277,617	$ 264,758	$ 1,040,751
Operating Margin	16,042	15,457	16,392	13,526	61,417
Net Margin	2,962	2,932	2,977	2,913	11,784

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Effectiveness of Disclosure Controls and Procedures

As of the end of the period covered by this report, our management, including the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer conducted an evaluation of the effectiveness of our disclosure controls and procedures. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that all material information required to be filed in this report has been made known to them in a timely matter. We have established a Disclosure Assessment Committee comprised of members from senior and middle management to assist in this evaluation. There have been no significant changes in our internal controls over financial reporting or in other factors that could significantly affect such controls during the previous fiscal year.

Management's Analysis on Internal Controls over Financial Reporting

Our management has assessed our internal control over financial reporting as of December 31, 2009, based on criteria for effective internal control over financial reporting described in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that as of December 31, 2009, our system of internal control over financial reporting was properly designed and operating effectively based upon the specified criteria. We have not identified any material weaknesses in our internal controls over financial reporting.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is comprised of policies, procedures, and reports designed to provide reasonable assurance to our management and board of directors that the financial reporting and the preparation of the financial statements for external reporting purposes has been handled in accordance with accounting principles generally accepted in the United States. Internal control over financial reporting includes those policies and procedures that (1) govern records to accurately and fairly reflect the transactions and dispositions of assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable safeguards against or timely detection of material unauthorized acquisition, use or disposition of our assets.

Changes in Internal Controls over Financial Reporting

There have been no significant changes in our internal controls over financial reporting that could significantly affect such controls during the previous fiscal year.

Inherent Limitations on Internal Control

There are inherent limitations to the effectiveness of any system of internal control over financial reporting. No control system can provide absolute assurance that all control issues and instances of error or fraud, if any, have been detected. Even the best designed system can only provide reasonable assurance that the objectives of the control system have been met. Because of these inherent limitations, internal controls over financial reporting may not prevent or detect all misstatements. Additionally, projections as to the effectiveness of controls to future periods are subject to the risk that controls may not continue to operate at their current effectiveness levels due to changes in personnel or in our operating environment.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors

We are governed by a board of 23 directors, consisting of two representatives from each of our member distribution cooperatives and one representative from TEC. Pursuant to our bylaws, each of our eleven member distribution cooperatives, in good standing, may recommend candidates to the nominating committee of our board of directors. At the annual meeting each year, the nominating committee nominates candidates for election to our board of directors. At least one candidate from each member distribution cooperative must be a director of that member distribution cooperative. Currently and historically, the other candidate from each member distribution cooperative is the chief executive officer of that member distribution cooperative. The candidates for director are elected to our board of directors by a majority of the voting delegates from our member distribution cooperatives. Each member distribution cooperative has one voting delegate. We do not control who the member distribution cooperative recommends to the nominating committee. As a result, our board of directors has not developed criteria, such as diversity, for use in identifying nominees to our board of directors. One director currently serves as a director on behalf of a member distribution cooperative and TEC. Each elected candidate is authorized to represent that member for a renewable term of one year at our annual meeting. Our board of directors sets policy and provides direction to our President and Chief Executive Officer ("CEO"). Our board of directors meets approximately eleven times each year.

Information concerning our directors, including principal occupation and employment during the past five years, qualifications, attributes, skills, and directorships in public corporations, if any, is listed below.

John William Andrew, Jr. (56). President and Chief Executive Officer of Delaware Electric Cooperative, Inc. since January 2005. Mr. Andrew also served as its Vice President, Engineering and Operations from 1998 to 2004. Mr. Andrew has held executive positions in the utility industry for more than a decade and has been a director of ODEC since 2005.

M Dale Bradshaw (56). Chief Executive Officer of Prince George Electric Cooperative since 1995. Mr. Bradshaw has held executive positions in the utility industry for more than 15 years and has been a director of ODEC since 1995.

Vernon N. Brinkley (63). President and Chief Executive Officer of A&N Electric Cooperative since 2003. Mr. Brinkley also served as President of A&N Electric Cooperative from 1995 to 2003 and as Executive Vice President and General Manager from 1982 to 1995. Mr. Brinkley has held executive positions in the utility industry for more than three decades and has been a director of ODEC since 1982.

Darlene H. Carpenter (63). Realtor of Montague, Miller & Company Realtors, Inc. since 2006. Ms. Carpenter served as a vice president at Wachovia Bank, National Association from 1966 to 2001. Ms. Carpenter has been a director of ODEC since 2009 and a director of Rappahannock Electric Cooperative since 1984. Ms. Carpenter was a past director of National Rural Utilities Cooperative Finance Corporation where she completed two three-year terms including serving on the audit committee (chairman), the loan committee and the corporate relations committee

Glenn F. Chappell (66). Self-employed farmer since 1961. Mr. Chappell has been a director of ODEC since 1995 and a director of Prince George Electric Cooperative since 1985.

Earl C. Currin, Jr. (66*).* Retired, formerly Provost at Southside Community College where he served from 1970 to 2007. Dr. Currin taught both accounting and economics at the college level. Dr. Currin has been a director of ODEC since 2008 and a director of Southside Electric Cooperative since 1986.

Jeffrey S. Edwards (46). President and Chief Executive Officer of Southside Electric Cooperative since 2007. Prior to that Mr. Edwards served as Executive Vice President of Albemarle Electric Membership Cooperative from 1998 to 2007. Mr. Edwards has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2007.

Kent D. Farmer (52). President and Chief Executive Officer of Rappahannock Electric Cooperative since 2004. Mr. Farmer also served as Chief Operating Officer of Rappahannock Electric Cooperative from 1999 to 2004. Mr. Farmer has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2004.

Fred C. Garber (65). Retired, formerly President of Mt. Jackson Farm Service, from 1973 to 2003. Mr. Garber has been a director of ODEC since 2005 and a director of Shenandoah Valley Electric Cooperative since 1984.

Hunter R. Greenlaw, Jr. (64). President of Greenlaw, Edwards & Leake, Inc., a real estate development and general contracting company since 1974. Mr. Greenlaw has been a director of ODEC since 1991 and a director of Northern Neck Electric Cooperative since 1979.

Bruce A. Henry (64). Owner and Secretary/Treasurer of Delmarva Builders, Inc., since 1981. Mr. Henry has been a director of ODEC since 1993 and a director of Delaware Electric Cooperative, Inc. since 1978.

Frederick L. Hubbard (69). President and Chief Executive Officer of Choptank Electric Cooperative since 2001. Mr. Hubbard also served as Senior Vice President and Chief Executive Officer of Choptank Electric Cooperative, Inc. from 1991 to 2001. Mr. Hubbard has held executive positions in the utility industry for over two decades and has been a director of ODEC since 1991.

David J. Jones (61). Owner/operator of Big Fork Farms since 1970 and Vice President of Exchange Warehouse, Inc. from 1996 to 2007. Mr. Jones has been a director of ODEC since 1986 and a director of Mecklenburg Electric Cooperative since 1982.

Bruce M. King (63). General Manager of BARC Electric Cooperative since 2003. Prior to that Mr. King was General Manager of Cherryland Electric Cooperative from 1993 to 2002. Mr. King has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2003.

John C. Lee Jr. (49). President and Chief Executive Officer of Mecklenburg Electric Cooperative since 2008. Mr. Lee served as Vice President of Member and External Relations of ODEC from April 2004 to December 2007 and Vice President Cooperative Affairs/Assistant to the President of ODEC from March 2000 to March 2004. Mr. Lee has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2008.

Paul E. Owen (59). Retired, formerly Director of Business Management with Smithfield Deli Group since 1974. Mr. Owen has been a director of ODEC since 2007 and a director of Community Electric Cooperative since 2000.

James M. Reynolds (62). President of Community Electric Cooperative since 2001. Mr. Reynolds also served as General Manager of Community Electric Cooperative from 1977 to 2001. Mr. Reynolds has held executive positions in the utility industry for more than three decades and has been a director of ODEC since 1977.

*Myron D. Rummel (*57). President and Chief Executive Officer of Shenandoah Valley Electric Cooperative since 2005. Mr. Rummel also served as Vice President, Engineering and Operations of Shenandoah Valley Electric

Cooperative from 1993 to 2005. Mr. Rummel has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2005.

Keith L. Swisher (55). Owner/operator of Swisher Valley Farms, LLC since 1976. Mr. Swisher has been a Director of ODEC since 2008 and a director of BARC Electric Cooperative since 1981.

Philip B. Tankard (81). Retired, formerly CFO for Tankard Nurseries from 1988 to 2006. Mr. Tankard has been a director of ODEC since 2002 and a director of A&N Electric Cooperative since 1960.

Gregory W. White (57). President and Chief Executive Officer of Northern Neck Electric Cooperative since 2005. Mr. White served as Senior Vice President of Power Supply of ODEC from 2004 to 2005, Senior Vice President Engineering and Operations of ODEC from 2002 to 2004 and Senior Vice President Retail and Alliance Management of ODEC from 2000 to 2002. Mr. White has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2005.

Carl R. Widdowson (71). Self-employed farmer since 1956. Mr. Widdowson has been a director of ODEC since 1987 and a director of Choptank Electric Cooperative, Inc. since 1980.

Audit Committee Financial Expert

We presently do not have an audit committee financial expert because of our cooperative governance structure and the resulting experience all of our directors have with matters affecting electric cooperatives in their roles as a chief executive officer or director of one of our member distribution cooperatives. In addition, the audit committee employs the services of accounting and financial consultants as it deems necessary.

Executive Officers

Our President and Chief Executive Officer administers our day-to-day business and affairs. Our executive officers at December 31, 2009, their respective ages, positions and recent business experience are listed below.

Jackson E. Reasor (57). President and Chief Executive Officer of ODEC and the Virginia, Maryland and Delaware Association of Electric Cooperatives (the "VMDA"), an electric cooperative association which provides services to its members and certain other electric cooperatives, since 1998.

Robert L. Kees (57). Senior Vice President and Chief Financial Officer since January 2006. Mr. Kees also served as our Vice President and Controller from March 2004 to December 2005 and as Assistant Vice President and Controller from March 2000 to February 2004.

Lisa D. Johnson (44). Senior Vice President of Power Supply since May 2006. Prior to joining ODEC, Ms. Johnson served as Vice President of Mirant Corporation from 2001 to 2006.

Elissa M. Ecker (50). Vice President of Human Resources since November 2004. Prior to joining ODEC, Ms. Ecker served as Director of Human Resources of Xperts, Inc. from 2003 to 2004, and as Director of Human Resources of Securicor New Century, L.L.C. from 2002 to 2003.

The following individual served as an executive officer during a portion of 2009.

B. Lee McDaniel (57). Vice President of Information Technology from January 2008 to August 2009. Mr. McDaniel was employed by ODEC until August 3, 2009. Mr. McDaniel joined ODEC in 2004 and served as our Director of MIS from September 2005 to December 2007. Prior to joining ODEC, Mr. McDaniel served as a Consultant for Atlantic Resources Group in 2005 and served as Director, Richmond Data Center for ALCOA from 1973 to 2004.

Code of Ethics

We have a Code of Ethics which applies to our President and Chief Executive Officer, Senior Vice President and Chief Financial Officer, and Vice President and Controller. A copy of this Code of Ethics is available without charge by sending a written request for the Code of Ethics to Old Dominion Electric Cooperative, Attention Mr. Robert L. Kees, Senior Vice President and Chief Financial Officer, 4201 Dominion Boulevard, Glen Allen, VA 23060.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

General Philosophy

Our compensation philosophy has four objectives:

- attract and retain a qualified, diverse workforce through a competitive compensation program;
- provide equitable and fair compensation;
- support our business strategy; and
- ensure compliance with applicable laws and regulations.

Total Compensation Package

We compensate our President and Chief Executive Officer ("CEO") and other senior management through the use of a total compensation package which includes base salary, competitive benefits, and the potential of a bonus. Our CEO's base salary is derived from third party market data based upon national compensation surveys. The national compensation survey data includes data from the labor market for positions of similar responsibilities. The compensation of our CEO is reviewed by the executive committee of our board of directors and they provide a recommendation to our entire board of directors. The entire board of directors approves our CEO's compensation.

Targeted Overall Compensation

Our compensation program utilizes detailed job descriptions for all of our employees, including senior management with the exception of the CEO, as an instrument to establish benchmarked positions. The market compensation information for each position is derived from salary data provided by third parties through national surveys and includes salary data for positions within the determined competitive labor market. Our job descriptions are reviewed annually and include essential and non-essential responsibilities, required knowledge, skills and abilities, and formal education and experience necessary to accomplish the requirements of the position which in turn helps us achieve operational goals. Utilizing this information, our human resources department determines a market-based salary for each position based upon salary survey data provided by third parties. A third-party consultant reviews the market-based salary data we compiled for reasonableness and fairness annually. Our board of directors has defined market-based salary as approximately 95% to 100% of the 50th percentile of the market, excluding new hires that may be hired at 90% of the 50th percentile of market until a learning period is complete.

Process

We have a committee of our board of directors, the executive committee, which recommends all compensation and awards for our CEO to the entire board of directors and the entire board of directors approves the compensation. Our board of directors has delegated to our CEO the authority to establish and adjust compensation for all employees other than him. The compensation for all other employees, including members of senior management other than the CEO, is approved by our CEO based upon market-based salary data. On an annual basis our board of directors reviews the performance and compensation of our CEO and our CEO reviews the performance and compensation of the remaining senior management.

Our CEO is also the CEO of the VMDA and their board of directors also approves the compensation of the CEO.

Base Salaries

We are an electric cooperative and do not have any stock and as a result, we do not have equity-based compensation programs. For this reason, substantially all of our compensation to our executive officers is provided in the form of base salary. We want to provide our senior management with a level of assured cash compensation in the form of base salary that is commensurate with the duties and responsibilities of their positions. These salaries were determined based on market data and internal structure for positions with similar responsibilities.

Bonuses

Our practice has been to, on infrequent occasions, award cash bonuses related to a specific event, such as the consummation of a significant transaction. On an annual basis, our board of directors determines the bonus criteria for our CEO and our CEO determines bonus criteria for all other executive officers. At the discretion of our board of directors, our CEO may be awarded an annual bonus; and, at the discretion of our CEO, other members of senior management may be awarded an annual bonus. Our CEO was awarded a bonus of $20,000 in 2009 for successful completion of the negotiation of the wholesale power contracts with our member distribution cooperatives in 2008 and the resolution of the dispute with NOVEC in 2008. The other members of our senior management were not awarded a bonus in any of the last three years.

Severance Benefits

We believe that companies should provide reasonable severance benefits to the CEO. With respect to our CEO, these severance benefits reflect the fact that it may be difficult to find comparable employment within a short period of time. In addition, while it is possible to provide salary continuation to a CEO during the job search process, which in some cases may be less expensive than a lump-sum severance payment, we prefer to pay a lump-sum severance payment to sever the relationship as soon as practicable if the severance is for cause. Our CEO's contractual rights to amounts following severance are set forth in his employment agreement. None of our other members of senior management have any contractual severance benefits.

Plans

Retirement Plans

We maintain a defined benefit pension plan which is available to all employees, with limited exceptions, who work at least 1,000 hours per year. This plan is a qualified pension plan under Section 401(a) of the Internal Revenue Code. Benefits, which accrue under the plan, are based upon the base annual salary as of November of the previous year.

We also have a 401(k) plan which is available to all employees in regular positions. Under the 401(k) plan for 2009, employees may elect to have up to 100% or $16,500, whichever is less, of their salary withheld on a pre-tax basis, subject to Internal Revenue Service limitations, and invested on their behalf. We match up to the first 2% of each participant's base salary. Also, a catch-up contribution is available for participants in the plan once they attain age 50. The maximum catch-up contribution for 2009 was $5,500.

In addition, in 2006 we entered into a non-qualified executive deferred compensation plan (the "Deferred Compensation Plan"). Our board of directors, at its discretion, determines who may participate in the plan as well as an annual contribution, if any, up to the maximum amount allowed by regulations. Currently, our board of directors has determined that our CEO is the only participant in this plan and we made a $15,000 contribution to the plan each year since 2006 for his benefit.

Pension Restoration Plan

We participate in a pension restoration plan, which is intended to provide a supplemental benefit for employees who would have a reduction in their pension benefit because of the Internal Revenue Code limitations. Currently, our CEO, Senior Vice President and Chief Financial Officer, and Senior Vice President of Power Supply are the only participants in this plan. Other executive officers may participate in this plan in the future.

Perquisites and Other Benefits

Our board of directors reviews the perquisites that our CEO receives during contract discussions with our CEO. The perquisite for Mr. Reasor is expenses for personal use of a company automobile which amounted to $3,583 in 2009 and $2,859 in 2008.

Senior management also participates in our other benefit plans on the same terms as other employees. These plans include the defined benefit pension plan, the 401(k) plan, medical and dental insurance, vision insurance, life insurance and accidental death and dismemberment, long-term disability, long-term care insurance, supplemental life insurance, supplemental accidental death and dismemberment, medical reimbursement and dependent care flexible spending accounts, health club membership, vacation, holiday and sick leave. Relocation benefits are reimbursed for all employees who transfer to another location at the request or convenience of ODEC in accordance with our relocation policy. We believe these benefits are customary for similar employers.

Change in Control

There is no provision in our CEO's employment agreement or any other arrangements with any other members of senior management that increases or decreases any amounts payable to him or her as a result of a change in control.

Summary Compensation Table

The following table sets forth information concerning compensation awarded to, earned by or paid to our CEO, our chief financial officer and three other senior executive officers for services rendered to us in all capacities during each of the last three fiscal years. The table also identifies the principal capacity in which each of these executives serves or served.

SUMMARY COMPENSATION

Name and Principal Position	Year	Salary	Bonus	Change in Pension Value and Non-Qualified Deferred Compensation	All Other Compensation[1]	Total
Jackson E. Reasor	2009	$ 419,583	$ 20,000	$ 169,505	$ 88,957	$ 698,045
President and Chief	2008	394,583	-	138,158	73,959	606,700
Executive Officer	2007	371,667	-	108,570	70,656	550,893
Robert L. Kees	2009	254,850	-	178,346	53,251	486,447
Senior Vice President and	2008	243,320	-	139,957	45,155	428,432
Chief Financial Officer	2007	231,733	-	107,144	43,085	381,962
Lisa D. Johnson	2009	294,164	-	14,896	59,418	368,478
Senior Vice President Power	2008	274,379	-	9,427	48,282	332,088
Supply	2007	249,600	-	2,818	28,484	280,902
Elissa M. Ecker	2009	172,698	-	27,251	36,454	236,403
Vice President of Human	2008	166,056	-	48,893	30,365	245,314
Resources	2007	154,524	-	10,146	28,193	192,863
B. Lee McDaniel [2][3][4]	2009	208,362	-	26,483	23,614	258,459
Vice President of	2008	157,813	-	25,167	22,517	205,497
Information Technology						

(1) The items included in All Other Compensation are identified in the All Other Compensation table.
(2) Mr. McDaniel became an executive officer on January 1, 2008.
(3) Mr. McDaniel was employed by ODEC until August 3, 2009.
(4) Includes a severance payment of $84,923.

Employment Agreement

In 2006, ODEC entered into an employment agreement with Jackson E. Reasor, our CEO. The agreement is for the term of five years, with an automatic one-year extension unless Mr. Reasor or ODEC and the VMDA (collectively, the "Employer") give written notice 30 days prior to the expiration of the agreement. The agreement provides that he will receive an annual salary of $360,000, effective as of June 1, 2006, subject to annual adjustment by the boards of directors of the Employer. The boards of directors of the Employer also may grant Mr. Reasor an annual bonus at their discretion. Mr. Reasor will also be entitled to participate in all benefit plans available to the employees of the Employer. The VMDA contributed $45,000 of Mr. Reasor's salary in 2009 and is expected to contribute the same amount in 2010.

Under the agreement, if Mr. Reasor voluntarily terminates his employment following material breach by the Employer or the Employer terminates him without specified cause, the Employer will pay Mr. Reasor a salary at the rate in effect on the date of termination for one year, plus medical insurance benefits, with limited exceptions. If the agreement is not continued at the end of the stated term, the Employer will pay Mr. Reasor a salary at the rate in effect on the date of termination for six months.

Where the termination is without "cause" or the CEO terminates employment for "good reason" the employment agreement provides for benefits equal to one year of base salary and medical insurance. However, the medical insurance will cease if he becomes eligible for medical insurance coverage by virtue of his employment with another company. In addition, a terminated CEO is entitled to receive any benefits that he otherwise would have been entitled to receive under our 401(k) plan, frozen pension plan and supplemental retirement plans, although those benefits are not increased or accelerated. We believe that these levels are consistent with the general practice among generation and transmission cooperatives, although we have not conducted a study to confirm this.

Based upon a hypothetical termination date of December 31, 2009, the severance benefits for Mr. Reasor would have been entitled to would be as follows:

Base Salary	$ 430,000
Targeted bonus	-
Healthcare and other insurance benefits	13,154
Total	$ 443,154

Under our employment contract with Mr. Reasor, "cause" is defined as (1) gross incompetence, insubordination, gross negligence, willful misconduct in office or breach of a material fiduciary duty, which includes a breach of confidentiality; (2) conviction of a felony, a crime of moral turpitude or commission of an act of embezzlement or fraud against ODEC or the VMDA or any subsidiary or affiliate thereof; (3) the CEO's material failure to perform a substantial portion of his duties and responsibilities hereunder, but only after Employer provides the CEO written notice of such failure and gives him 30 days to remedy the situation; or the (4) deliberate dishonesty of the CEO with respect to ODEC or any of its subsidiaries or affiliates.

The CEO may terminate his employment with or without good reason by written notice to the boards of directors effective 60 days after receipt of such notice by the board of directors. If the CEO terminates his employment for good reason, then the CEO is entitled to the salary specified above in the "without cause" paragraph. The CEO will not be required to render any further services. Upon termination of employment by the CEO without good reason, then the CEO is not entitled to further compensation. "Good reason" is the Employer's failure to maintain compensation and benefits or the Employer's material breach of any provision of the employment contract, which failure or breach continued for more than 30 days after the date on which our board of directors received such notice.

Defined Benefit Plan

We have elected to participate in the NRECA Retirement Security Program (the "Plan"), a noncontributory, defined benefit, multiple-employer, master pension plan maintained and administered by the NRECA for the benefit of its member systems and their employees. The Plan is a qualified pension plan under Section 401(a) of the Internal Revenue Code of 1986. The following table lists the estimated value of the current accumulated pension benefit payable at "normal retirement age," age 62, for participants in the specified final average salary and years of benefit service categories for the given current multiplier of 1.7%. Lump sums at normal retirement age are then discounted to the last day of the appropriate year. Benefits, which accrue under the Plan, are based upon the base annual salary as of November of the previous year. As a result of changes in Internal Revenue Service regulations, the base annual salary used in determining benefits is limited to $245,000 effective January 1, 2010.

PENSION BENEFITS

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Year
Jackson E. Reasor	NRECA Retirement Security Plan	10.08	$ 510,944	$ -
	Pension Restoration Plan	10.08	296,167	-
Robert L. Kees	NRECA Retirement Security Plan	17.00	744,309	-
	Pension Restoration Plan	17.00	1,337	-
Lisa D. Johnson	NRECA Retirement Security Plan	2.58	24,868	-
	Pension Restoration Plan	2.58	2,273	-
Elissa M. Ecker	NRECA Retirement Security Plan	4.08	92,042	-
B. Lee McDaniel(1)	NRECA Retirement Security Plan	2.25	77,429	-

(1) Mr. McDaniel was employed by ODEC until August 3, 2009.

The pension benefits indicated above are the estimated amounts payable by the Plan, and they are not subject to any deduction for Social Security or other offset amounts. The participant's annual pension at his or her normal retirement date is equal to the product of his or her years of benefit service times final average salary times the multiplier in effect during years of benefit service. The multiplier was 1.7% commencing January 1, 1992. The number of years of credited service is as of the end of the current year for each of the named executives. The present value of accumulated benefit is calculated assuming that the executive retires at the normal retirement age per the plan, but using current number of years of credited service, and that he or she receives a lump sum. The lump sum amounts are calculated using the 30-year Treasury rate (4.00% for 2009 and 4.52% for 2008) and the Pension Protection Act ("PPA") three segment yield rates (5.24%, 5.69% and 5.37% for 2009 and 4.60%, 4.82%, and 4.91% for 2008) and the required Internal Revenue Service mortality table for lump sum payments (1994 GAS, projected to 2002, blended 50%/50% for unisex mortality in combination with the 30-year Treasury rates and RP 2000 PPA at 2009 combined unisex 50%/50% mortality in combination with the PPA rates.) Lump sums at normal retirement age are then discounted to the last day of the appropriate year using these same assumptions shown for the respective stated interest rates.

We participate in a pension restoration plan, which is intended to provide a supplemental benefit for employees who would have a reduction in their pension benefit from the Retirement Security Plan because of the Internal Revenue Code limitations.

Deferred Compensation Plan

In 2006, in connection with the execution of the employment agreement with Mr. Reasor, we adopted the Deferred Compensation Plan for the purpose of providing supplemental deferred compensation to Mr. Reasor in an amount within the statutory maximums permitted under Section 457 of the Internal Revenue Code. The Deferred Compensation Plan is restricted to those executive employees designated by our board of directors who are generally responsible for ongoing operations, responsible for and have general supervision over the overall financial condition, setting and executing overall corporate policies and practices, and supervising large numbers of employees and who elect to participate in the Deferred Compensation Plan by agreeing to a deferral of a portion of their current compensation. Currently, Mr. Reasor is the only participant in the Deferred Compensation Plan. Under the Deferred Compensation Plan, annual deferrals cannot exceed 100% of Mr. Reasor's annual compensation or $16,500 (for 2009), adjusted by and subject to specified tax laws (the "deferral limit"), during any year in which we are exempt from federal income taxation. During the last three years before Mr. Reasor attains the normal retirement age under our primary pension plan, currently age 62, the deferral limit is increased to the lesser of two times the deferral limit or the deferral limit plus the amount Mr. Reasor was eligible to but did not defer under the Deferred Compensation Plan. Amounts credited to him under the Plan will be credited with earnings or losses equal to those made by an investment in one or more funds of a specified regulated investment company designated by him. Distributions under the Deferred Compensation Plan generally commence upon severance of employment, whether upon termination, retirement or death.

The following table sets forth the non-qualified deferred compensation paid to our executive officers in 2009:

NON-QUALIFIED DEFERRED COMPENSATION BENEFITS TABLE

Name	Executive Contributions in Last Fiscal Year [1]	Registrant Contributions in Last Fiscal Year [1]	Aggregate Gains in Last Fiscal Year	Aggregate Withdrawals/ Distributions	Aggregate Balance at Last Fiscal Year End
Jackson E. Reasor	$ -	$ 15,000	$ 12,477	$ -	$ 56,555
Robert L. Kees	n/a	n/a	n/a	n/a	n/a
Lisa D. Johnson	n/a	n/a	n/a	n/a	n/a
Elissa M. Ecker	n/a	n/a	n/a	n/a	n/a
B. Lee McDaniel[2]	n/a	n/a	n/a	n/a	n/a

(1) These amounts are not included in the summary compensation table.
(2) Mr. McDaniel was employed by ODEC until August 3, 2009.

The following table sets forth information concerning all other compensation awarded to, earned by or paid to these executives during the last completed fiscal year.

ALL OTHER COMPENSATION

Name	Perquisites and Other Personal Benefits [1]	Company Contributions to Defined Benefit Plans	Company-paid Insurance Premiums	All Other Compensation
Jackson E. Reasor[2]	$ 8,483	$ 78,530	$ 1,944	$ 88,957
Robert L. Kees	4,900	47,180	1,171	53,251
Lisa D. Johnson	4,900	53,198	1,320	59,418
Elissa M. Ecker	3,454	32,198	802	36,454
B. Lee McDaniel[3]	1,986	21,103	525	23,614

(1) Perquisites and other personal benefits is composed of contributions made by ODEC to the 401(k) plan.
(2) Perquisites and other personal benefits include $3,583 for personal use of a company automobile.
(3) Mr. McDaniel was employed by ODEC until August 3, 2009.

Board of Directors Compensation

It is our policy to compensate the members of our board of directors who are not employed by one of our member distribution cooperatives ("outside directors"). Our outside directors were compensated by a monthly retainer of $2,000 in 2009. They are also paid for meetings at a rate of $400 per in person meeting and $200 per teleconference, if the meeting date falls outside the normal board of directors meeting dates. All directors are reimbursed for out-of-pocket expenses incurred in attending meetings. Our directors receive no other compensation. Our directors do not have pension benefits, non-equity incentive plan compensation, or other perquisites and because we are a cooperative, we do not have stock or other equity options. The following table sets forth the compensation we paid to our directors in 2009:

DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash[1]
Darlene H. Carpenter	$ 11,200
Glenn F. Chappell	25,400
Earl C. Currin, Jr.	26,200
William C. Frazier	20,400
Fred C. Garber	25,800
Hunter R. Greenlaw, Jr.	25,800
Bruce A. Henry	25,200
David J. Jones	26,200
Paul E. Owen	24,400
Keith L. Swisher	25,200
Philip B. Tankard	25,200
Carl R. Widdowson	25,800
	$286,800

(1) Our directors received no compensation from us other than as set forth in this column.

Compensation Committee Interlocks and Insider Participation

As described above, our executive committee of our board of directors establishes and the full board of directors approves all compensation and awards to the CEO. Our board of directors has delegated to our CEO the authority to establish and adjust compensation for all employees other than himself. No member of our board of directors is or previously was an officer or employee of ODEC or is or has engaged in transactions with ODEC, with two exceptions. Mr. Gregory W. White was an employee of ODEC from 1995 to 2005 when he left his position as Senior Vice President of Power Supply to become the President and Chief Executive Officer of Northern Neck Electric Cooperative, one of our member distribution cooperatives. Mr. John C. Lee, Jr. was an employee of ODEC from 1992 to 2007 when he left his position as Vice President of Member and External Relations to become the President and Chief Executive Officer of Mecklenburg Electric Cooperative, one of our member distribution cooperatives. Our executive committee does not have a charter. Our directors are, however, employees or directors of our member distribution cooperatives.

Compensation Committee Report

The executive committee serves as the compensation committee of the board of directors and has reviewed and discussed with the management of ODEC the contents of the section entitled "Compensation Discussion and Analysis" and based on such review and discussion has recommended to the board of directors its inclusion in this annual report.

James M. Reynolds, Chairman.
Fred C. Garber
Bruce A. Henry
Frederick L. Hubbard
David J. Jones
Gregory W. White

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Not Applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Because we are a cooperative, all of our directors are representatives of our member distribution cooperatives, which are our principal customers. Due to the extent of the payments by each member distribution cooperative to us, our directors are not independent based on the definition of "independence" of the New York Stock Exchange.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table presents fees for services provided by Ernst & Young LLP for fiscal years 2009 and 2008. All Audit, Audit-Related, and Tax Fees shown below were pre-approved by the Audit Committee in accordance with its established procedures.

	2009	2008
Audit Fees (a)	$ 389,503	$ 252,908
Audit-Related Fees (b)	-	6,975
Tax Fees (c)	4,900	9,050
Total	$ 394,403	$ 268,933

a) Fees for professional services provided for the audit of ODEC's annual financial statements as well as reviews of ODEC's quarterly reports on Form 10-Q, accounting consultations on matters addressed during the audit or interim reviews, and SEC filings and offering memorandums including comfort letters, consents, and comment letters.
b) Fees for professional services which principally include accounting consultations and services in connection with internal control matters.
c) Fees for professional services for tax-related advice and compliance.

For fiscal years 2009 and 2008, other than those fees listed above, we did not pay Ernst & Young LLP any fees for any other products or services.

Audit Committee Preapproval Process for the Engagement of Auditors

All audit, tax and other services to be performed by Ernst & Young LLP for us must be pre-approved by the Audit Committee. The Audit Committee reviews the description of the services and an estimate of the anticipated costs of performing those services. Pre-approval is granted usually at regularly scheduled meetings. During 2009 and 2008, all services performed by Ernst & Young LLP were pre-approved by the Audit Committee in accordance with this policy.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

a) The following documents are filed as part of this Form 10-K.

1. Financial Statements

See Index on page 45

2. Financial Statement Schedules

Not applicable.

3. Exhibits

Exhibits

*3.1 Amended and Restated Articles of Incorporation of Old Dominion Electric Cooperative (filed as exhibit 3.1 to the Registrant's Form 10-Q, File No. 33-46795, filed on August 11, 2000).

*3.2 Bylaws of Old Dominion Electric Cooperative, Amended and Restated as of December 31, 2008, as amended on November 11, 2008 (filed as exhibit 3 to the Registrant's Form 8-K, File No. 000-50039, filed on November 14, 2008).

*4.1 Indenture of Mortgage and Deed of Trust, dated as of May 1, 1992, between Old Dominion Electric Cooperative and Crestar Bank, as Trustee (filed as exhibit 4.1 to the Registrant's Form 10-K for the year ended December 31, 1992, File No. 33-46795, filed on March 30, 1993).

*4.2 Third Supplemental Indenture, dated as of May 1, 1993, to the Indenture of Mortgage and Deed of Trust, dated as of May 1, 1992, between Old Dominion Electric Cooperative and Crestar Bank, as Trustee, including the form of the First Mortgage Bonds, 1993 Series A (filed as exhibit 4.1 to the Registrant's Form 10-Q for the quarter ended June 30, 1993, File No. 33-46795, filed on August 10, 1993).

*4.3 Fourth Supplemental Indenture, dated as of December 15, 1994, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and Crestar Bank, as Trustee (filed as exhibit 4.5 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*4.4 Eleventh Supplemental Indenture, dated as of September 1, 2001, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank (formerly Crestar Bank), as Trustee, including the form of the 2001 Series A Bond (filed as exhibit 4.1 to the Registrant's Form 10-Q/A for the quarter ended September 30, 2001, File No. 33-46795, filed on November 20, 2001).

*4.5 Thirteenth Supplemental Indenture, dated as of November 1, 2002, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank (formerly Crestar Bank), as Trustee, including the form of the 2002 Series A Bond (filed as exhibit 4.14 to Amendment No. 1 to the Registrant's Form S 3, File No. 333-100577, on November 25, 2002).

*4.6 Fourteenth Supplemental Indenture, dated as of December 1, 2002, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank (formerly Crestar Bank), as Trustee, including the form of the 2002 Series B Bond (filed as exhibit 4.1 to the Registrant's Form 8-K, File No. 000-50039, on December 27, 2002).

*4.7 Fifteenth Supplemental Indenture, dated as of May 1, 2003, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank (formerly Crestar Bank), as Trustee (filed as Exhibit 4.A to the Registrant's Form 10-K for the year ended December 31, 2003, File No. 000-50039, on March 22, 2004).

*4.8 Sixteenth Supplemental Indenture, dated as of July 1, 2003, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank (formerly Crestar Bank), as Trustee, including the form of the 2003 Series A Bond (filed as Exhibit 4.1 to the Registrant's Form 8-K, File No. 000-50039, on July 25, 2003).

*4.9 Seventeenth Supplemental Indenture, dated as of January 1, 2004, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank (formerly Crestar Bank), as Trustee (filed as Exhibit 4.B to the Registrant's Form 10-K for the year ended December 31, 2003, File No 000-50039, on March 22, 2004).

*4.10 Amended and Restated Indenture, dated as of September 1, 2001, between Old Dominion Electric Cooperative and SunTrust Bank, as Trustee (filed as exhibit 4.2 to Registrant's Form 10-Q/A for the quarter ended September 30, 2001, File No. 33-46795, filed on November 20, 2001).

*4.11 First Supplemental Indenture, dated as of December 1, 2002, to the Amended and Restated Indenture, dated as of September 1, 2001, between Old Dominion Electric Cooperative and SunTrust Bank, as Trustee (filed as Exhibit 4.2 to the Registrant's Form 8-K, File No. 000-50039, on December 27, 2002).

*10.1 Nuclear Fuel Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of December 28, 1982, amended and restated October 17, 1983 (filed as exhibit 10.1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.2 Purchase, Construction and Ownership Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of December 28, 1982, amended and restated October 17, 1983 (filed as exhibit 10.2 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.3 Clover Purchase, Construction and Ownership Agreement between Old Dominion Electric Cooperative and Virginia Electric and Power Company, dated as of May 31, 1990 (filed as exhibit 10.4 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.4 Amendment No. 1 to the Clover Purchase, Construction and Ownership Agreement between Old Dominion Electric Cooperative and Virginia Electric and Power Company, effective March 12, 1993 (filed as exhibit 10.34 to the Registrant's Form S-1 Registration Statement, File No. 33-61326, filed on April 19, 1993).

*10.5 Clover Operating Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of May 31, 1990 (filed as exhibit 10.6 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.6 Amendment to the Clover Operating Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, effective January 17, 1995 (filed as exhibit 10.8 to the Registrant's Form 10-K for the year ended December 31, 1994, File No. 33-46795, on March 15, 1995).

*10.7 Lease Agreement between Old Dominion Electric Cooperative and Regional Headquarters, Inc., dated July 29, 1986 (filed as exhibit 10.27 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.8 Nuclear Decommissioning Trust Agreement between Old Dominion Electric Cooperative and Bankers Trust Company, dated March 1, 1991 (filed as exhibit 10.29 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.9 Form of Salary Continuation Plan (filed as exhibit 10.31 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*, ****10.10 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and A&N Electric Cooperative, dated April 24, 1992 (filed as exhibits 10.2 and 10.3 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2008, File No. 33-46795, filed on November 11, 2008).

*10.11 Interconnection Agreement between Delmarva Power & Light Company and Old Dominion Electric Cooperative, dated November 30, 1999 (filed as exhibit 10.33 to the Registrant's Form 10-K for the year ended December 31, 2000, File No. 33-46795, on March 19, 2001).

**10.12 Participation Agreement, dated as of February 29, 1996, among Old Dominion Electric Cooperative, State Street Bank and Trust Company, the Owner Participant named therein and Utrecht America Finance Co (filed as exhibit 10.35 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.13 Clover Unit 1 Equipment Interest Lease Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Equipment Head Lessor, and State Street Bank and Trust Company, as Equipment Head Lessee (filed as exhibit 10.36 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.14 Equipment Operating Lease Agreement, dated as of February 29, 1996, between State Street Bank and Trust Company, as Lessor, and Old Dominion Electric Cooperative, as Lessee (filed as exhibit 10.37 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.15 Corrected Option Agreement to Lease, dated as of February 29, 1996, among Old Dominion Electric Cooperative and State Street Bank and Trust Company (filed as exhibit 10.38 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.16 Clover Agreements Assignment and Assumption Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Assignor, and State Street Bank and Trust Company, as Assignee (filed as exhibit 10.39 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.17 Payment Undertaking Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative and Cooperative Centrale Raiffeisen Boerenleenbank B.A., "Rabobank Nederland", New York Branch (filed as exhibit 10.42 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.18 Payment Undertaking Pledge Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Payment Undertaking Pledgor, and State Street Bank and Trust Company, as Payment Undertaking Pledgee (filed as exhibit 10.43 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.19 Pledge Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Pledgor, and State Street Bank and Trust Company, as Pledgee (filed as exhibit 10.44 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.20 Tax Indemnity Agreement, dated as of February 29, 1996, among Old Dominion Electric Cooperative, State Street Bank and Trust Company, the Owner Participant named therein and Utrecht America Finance Co. (filed as exhibit 10.45 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.21 Tax Indemnity Agreement, dated as of July 1 1996, between Old Dominion Electric Cooperative and the Owner Participant named therein (filed as exhibit 10.59 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.22 Amendment No. 3 to Participation Agreement (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

**10.23 Amendment No. 2 to Equipment Operating Lease Agreement (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

**10.24 Amendment No. 2 to Corrected Foundation Operating Lease Agreement (filed as Exhibit 10.3 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

**10.25 Investment Agreement (filed as Exhibit 10.4 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

**10.26 Investment Pledge Agreement (filed as Exhibit 10.5 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

**10.27 Amendment No. 3 to Payment Undertaking Agreement (filed as Exhibit 10.6 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

**10.28 Amendment No. 2 to Tax Indemnity Agreement (filed as Exhibit 10.7 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

**10.29 Employment Agreement, dated June 1, 2006, between Old Dominion Electric Cooperative and Jackson E. Reasor and accepted by Jackson E. Reasor on December 18, 2006 (filed as Exhibit 10.1 to the Registrant's Form 8-K, File No. 000-50039, on December 21, 2006).

**10.30 Executive Deferred Compensation Plan, dated June 30, 2006, adopted on December 18, 2006 (filed as Exhibit 10.2 to the Registrant's Form 8-K File No. 000-50039, on December 21, 2006).

**10.31 Employment letter, dated November 28, 2005, of Old Dominion Electric Cooperative and agreed and accepted by Robert L. Kees (filed as exhibit 10.1 to the Registrant's Form 8-K, No. 000-50039, on November 28, 2005).

**10.32 Amendment No. 1 to Participation Agreement, dated as of December 19, 2002, among Old Dominion Electric Cooperative, State Street Bank and Trust Company, the Owner Participant named therein, Utrecht America Finance Co and Cedar Hill International Corp.

**10.33 Amendment No. 1 to Equipment Operating Lease Agreement, dated as of December 19, 2002, between State Street Bank and Trust Company, as Lessor, and Old Dominion Electric Cooperative, as Lessee.

**10.34 Amendment No. 1. to Corrected Foundation Operating Lease Agreement, dated as of December 19, 2002, between State Street Bank and Trust Company, as Foundation Lessor and Old Dominion Electric Cooperative, as Foundation Lessee.

**10.35 Amendment No. 2 to Payment Undertaking Agreement, dated as of December 19, 2002 between Old Dominion Electric Cooperative and Cooperatieve Centrale Raiffeisen Boerenleenbank B.A., "Rabobank Nederland", New York Branch.

*10.36 Amendment No. 1 to Tax Indemnity Agreement, dated as of December 19, 2002, between Old Dominion Electric Cooperative and the Owner Participant named therein.

**10.37 Amendment No. 2 to Participation Agreement, dated as of December 31, 2004, between and among Old Dominion Electric Cooperative, U.S. Bank National Association, Wachovia Bank, National Association, Utrecht-America Finance Co., and Cedar Hill International Corp. (filed as exhibit 10.1 to the Registrant's Form 8-K, File No. 000-50039, on January 13, 2005).

*10.38 Mutual Operating Agreement, dated as of May 18, 2005, between Virginia Electric and Power Company and Old Dominion Electric Cooperative.

*10.39 Employment letter, dated March 30, 2007, of Old Dominion Electric Cooperative and agreed and accepted by Bryan S. Rogers (filed as exhibit 10.1 to the Registrant's Form 8-K, No. 000-50039, on April 2, 2007).

21 Subsidiaries of Old Dominion Electric Cooperative (not included because Old Dominion Electric Cooperative's subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a "significant subsidiary" under Rule 102(w) of Regulation S-X).

23.1 Consent of Ernst & Young LLP

31.1 Certification of the Principal Executive Officer pursuant to Rule 13a-14(a)

31.2 Certification of the Principal Financial Officer pursuant to Rule 13a-14(a)

32.1 Certification of the Principal Executive Officer pursuant to 18 U.S.C. § 1350

32.2 Certification of the Principal Financial Officer pursuant to 18 U.S.C. § 1350

* Incorporated herein by reference.

** The lease relates to our interest in all of Clover Unit 1 and related common facilities, other than the foundations. At the time this lease was executed, we had entered into identical leases with respect to the foundations as part of the same transactions. We agree to furnish to the Commission, upon request, a copy of the lease of our interest in the foundations for Clover Unit 1.

*** This agreement consists of two separate signed documents, which have been combined.

**** This agreement is substantially similar in all material respects to the wholesale power contracts of our other member distribution cooperatives.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

OLD DOMINION ELECTRIC COOPERATIVE
Registrant

By: /s/ JACKSON E. REASOR
Jackson E. Reasor
President and Chief Executive Officer

Date: March 17, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the following capacities on March 17, 2010.

Signature	Title
/s/ JACKSON E. REASOR Jackson E. Reasor	President and Chief Executive Officer (Principal executive officer)
/s/ ROBERT L. KEES Robert L. Kees	Senior Vice President and Chief Financial Officer (Principal financial officer)
/s/ BRYAN S. ROGERS Bryan S. Rogers	Vice President and Controller (Principal accounting officer)
/s/ J. WILLIAM ANDREW, JR. J. William Andrew, Jr.	Director
/s/ M DALE BRADSHAW M Dale Bradshaw	Director
/s/ VERNON N. BRINKLEY Vernon N. Brinkley	Director
/S/ DARLENE H. CARPENTER Darlene H. Carpenter	Director
/s/ GLENN F. CHAPPELL Glenn F. Chappell	Director
/s/ EARL C. CURRIN, JR. Earl C. Currin, Jr.	Director

/s/ JEFFREY S. EDWARDS Jeffrey S. Edwards	Director
/s/ KENT D. FARMER Kent D. Farmer	Director
/s/ FRED C. GARBER Fred C. Garber	Director
/s/ HUNTER R. GREENLAW, JR. Hunter R. Greenlaw, Jr.	Director
/s/ BRUCE A. HENRY Bruce A. Henry	Director
/s/ FREDERICK L. HUBBARD Frederick L. Hubbard	Director
/s/ DAVID J. JONES David J. Jones	Director
/s/ BRUCE M. KING Bruce M. King	Director
/s/ JOHN C. LEE, JR. John C. Lee, Jr.	Director
/s/ PAUL E. OWEN Paul E. Owen	Director
/s/ JAMES M. REYNOLDS James M. Reynolds	Director
/s/ MYRON D. RUMMEL Myron D. Rummel	Director
/s/ KEITH L. SWISHER Keith L. Swisher	Director
/s/ PHILIP B. TANKARD Philip B. Tankard	Director

/s/ GREGORY W. WHITE Gregory W. White	Director
/s/ CARL R. WIDDOWSON Carl R. Widdowson	Director

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement (Form S-3 No. 33-10577) of Old Dominion Electric Cooperative and in the related Prospectus of our report dated March 16, 2010, with respect to the consolidated financial statements of Old Dominion Electric Cooperative and the effectiveness of internal control over financial reporting of Old Dominion Electric Cooperative included in this Annual Report (Form 10-K) for the year ended December 31, 2009.

/s/ Ernst & Young LLP

Richmond, VA
March 17, 2010

Exhibit 31.1

CERTIFICATIONS

I, Jackson E. Reasor, certify that:

1. I have reviewed this annual report on Form 10-K of Old Dominion Electric Cooperative;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

(a) designed such disclosure controls and procedures or caused such disclosure controls to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 17, 2010
/s/ JACKSON E. REASOR
Jackson E. Reasor
President and Chief Executive Officer
(Principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, Robert L. Kees, certify that:

1. I have reviewed this annual report on Form 10-K of Old Dominion Electric Cooperative;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

(a) designed such disclosure controls and procedures or caused such disclosure controls to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 17, 2010
/s/ ROBERT L. KEES
Robert L. Kees
Senior Vice President and Chief Financial Officer
(Principal financial officer)

Exhibit 32.1

OLD DOMINION ELECTRIC COOPERATIVE

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Old Dominion Electric Cooperative (the “Company”) on Form 10-K for the period ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Jackson E. Reasor, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: March 17, 2010

/s/JACKSON E. REASOR
Jackson E. Reasor
President and Chief Executive Officer
(Principal executive officer)

Exhibit 32.2

OLD DOMINION ELECTRIC COOPERATIVE

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Old Dominion Electric Cooperative (the "Company") on Form 10-K for the period ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert L. Kees, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: March 17, 2010

/s/ROBERT L. KEES
Robert L. Kees
Senior Vice President and Chief Financial Officer
(Principal financial officer)

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(d) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT.

ODEC does not solicit proxies from its cooperative members and thus is not required to provide an annual report to its security holders and will not prepare such a report after filing this Form 10-K for fiscal year 2009. Accordingly, ODEC will not file an annual report with the Securities and Exchange Commission.