UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

Amendment No. 1

FOR ANNUAL AND TRANSITION REPORTS

PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

(Mark One)

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

For the fiscal year ended December 31, 2003 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 1-4928

DUKE ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

North Carolina	**56-0205520**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
526 South Church Street, Charlotte, North Carolina	**28202-1803**

(Address of principal executive offices)	**(Zip Code)**

704-594-6200

(Registrant s telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, without par value	New York Stock Exchange, Inc.
6.375% Preferred Stock A, 1993 Series, par value $25	New York Stock Exchange, Inc.
7.20% Quarterly Income Preferred Securities issued by Duke Energy Capital Trust I and guaranteed by Duke Energy Corporation	New York Stock Exchange, Inc.
7.20% Trust Preferred Securities issued by Duke Energy Capital Trust II and guaranteed by Duke Energy Corporation	New York Stock Exchange, Inc.
Preference Stock Purchase Rights	New York Stock Exchange, Inc.
Series C 6.60% Senior Notes Due 2038	New York Stock Exchange, Inc.
Corporate Units	New York Stock Exchange, Inc.

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

Title of class

Preferred Stock, par value $100

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 and (2) has been subject to such filing requirements for the past 90 days. Yes x 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/A or any amendment to this Form 10-K/A. x

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes x No ¨

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant at June 30, 2003	$ 18,018,000,000
Number of shares of Common Stock, without par value, outstanding at March 2, 2004	912,888,377

Documents incorporated by reference:

The registrant is incorporating herein by reference certain sections of the proxy statement relating to the 2004 annual meeting of shareholders to provide information required by Part II, portions of Item 5, and Part III, Items 10, 11, 12,13 and 14 of this annual report.

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Explanatory Note

This Amendment No. 1 to the Annual Report on Form 10-K of Duke Energy Corporation (Duke Energy) for the fiscal year ended December 31, 2003 is being filed for the purpose of amending and revising Items 1, 2, 3, 6, 7, 8, 9A and 15. This Form 10-K/A is being filed in order to (1) present Duke Energy s real estate operations, Crescent Resources, LLC (Crescent), as a separate reportable segment (see Note 3 to the Consolidated Financial Statements), (2) to present the effects of additional discontinued operations as a result of the change within the Field Services reportable segment (see Note 12 to the Consolidated Financial Statements), (3) to revise certain financial statement captions related to Crescent (see Note 24 to the Consolidated Financial Statements), (4) to provide updates to significant litigation matters since the original filing date of March 15, 2004 (see Note 17 to the Consolidated Financial Statements), (5) to remove the presentation of consolidated earnings before interest and taxes (EBIT) pursuant to the Securities and Exchange Commission s rules on presentation of non-GAAP financial measures, and (6) to update for material subsequent events occurring since the original filing date of March 15, 2004 (see Note 23 to the Consolidated Financial Statements). These revisions did not affect consolidated net income, total assets, liabilities or stockholders equity.

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DUKE ENERGY CORPORATION

FORM 10-K/A FOR THE YEAR ENDED DECEMBER 31, 2003

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SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

Duke Energy Corporation s reports, filings and other public announcements may contain or incorporate by reference statements that do not directly or exclusively relate to historical facts. Such statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as may, will, could, project, believe, anticipate, expect, estimate, continue, potential, plan, forecast and other similar words. Those statemer Energy s intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors. Many of those factors are outside Duke Energy s control and could cause actual results to differ materially from the results expressed or implied by those forward-looking statements. Those factors include:

State, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures, and affect the speed at and degree to which competition enters the electric and natural gas industries

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The outcomes of litigation and regulatory investigations, proceedings or inquiries

Industrial, commercial and residential growth in Duke Energy s service territories

The weather and other natural phenomena

The timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates

General economic conditions, including any potential effects arising from terrorist attacks and any consequential hostilities or other hostilities

Changes in environmental and other laws and regulations to which Duke Energy and its subsidiaries are subject or other external factors over which Duke Energy has no control

The results of financing efforts, including Duke Energy s ability to obtain financing on favorable terms, which can be affected by various factors, including Duke Energy s credit ratings and general economic conditions

Lack of improvement or further declines in the market prices of equity securities and resultant cash funding requirements for Duke Energy s defined benefit pension plans

The level of creditworthiness of counterparties to Duke Energy s transactions

The amount of collateral required to be posted from time to time in Duke Energy s transactions

Growth in opportunities for Duke Energy s business units, including the timing and success of efforts to develop domestic and international power, pipeline, gathering, processing and other infrastructure projects

Competition and regulatory limitations affecting the success of Duke Energy s divestiture plans, including the prices at which Duke Energy is able to sell its assets

The performance of electric generation, pipeline and gas processing facilities

The extent of success in connecting natural gas supplies to gathering and processing systems and in connecting and expanding gas and electric markets

The effect of accounting pronouncements issued periodically by accounting standard-setting bodies and

Conditions of the capital markets and equity markets during the periods covered by the forward-looking statements

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Duke Energy has described. Duke Energy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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Item 1. Business.

GENERAL

Duke Energy Corporation (collectively with its subsidiaries, Duke Energy) is a leading energy company located in the Americas with an affiliated real estate operation. Duke Energy provides its services through the business segments described below.

Duke Energy operates the following business units: Franchised Electric, Natural Gas Transmission, Field Services, Duke Energy North America (DENA), International Energy and Crescent Resources, LLC (Crescent). Duke Energy s chief operating decision maker regularly reviews financial information about each of these business units in deciding how to allocate resources and evaluate performance. The entities under each business unit have similar economic characteristics, services, production processes, distribution methods and regulatory concerns. All of the Duke Energy business units are considered reportable segments under Statement of Financial Accounting Standards No. 131, Disclosures about Segments of an Enterprise and Related Information.

Franchised Electric generates, transmits, distributes and sells electricity in central and western North Carolina and western South Carolina. It conducts operations through Duke Power. These electric operations are subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC).

Natural Gas Transmission provides transportation and storage of natural gas for customers throughout the East Coast and Southern U.S., the Pacific Northwest, and in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and gas transportation and processing services to customers in Western Canada. Natural Gas Transmission does business primarily through Duke Energy Gas Transmission Corporation. Duke Energy Gas Transmission Corporation s natural gas transmission and storage operations in the U.S. are subject to the FERC s, the Texas Railroad Commission s, and the U.S. Department of Transportation s (DOT s) rules and regulations, while natural gas gathering, processing, transmission, distribution and storage operations in Canada are subject to the rules and regulations of the National Energy Board (NEB) or the Ontario Energy Board (OEB).

Field Services gathers, compresses, treats, processes, transports, trades and markets, and stores natural gas; and produces, transports, trades and markets, and stores natural gas liquids (NGLs). It conducts operations primarily through Duke Energy Field Services, LLC (DEFS), which is approximately 30% owned by ConocoPhillips and approximately 70% owned by Duke Energy. Field Services gathers natural gas from production wellheads in Western Canada and 10 states in the U.S. Those systems serve major natural gas-producing regions in the Western Canadian Sedimentary Basin, Rocky Mountain, Permian Basin, Mid-Continent and East Texas-Austin Chalk-North Louisiana areas, as well as onshore and offshore Gulf Coast areas.

DENA operates and manages merchant power generation facilities and engages in commodity sales and services related to natural gas and electric power around its generation assets and contractual positions. DENA conducts business throughout the U.S. and Canada generally through Duke Energy North America, LLC and Duke Energy Trading and Marketing, LLC (DETM). DETM is 40% owned by Exxon Mobil Corporation and 60% owned by Duke Energy. In 2003, Duke Energy discontinued the proprietary trading business at DENA, commenced actions to unwind DETM, and announced its intent to reduce its investment in merchant power generation facilities by selling its facilities in the Southeast U.S. and reducing its interests in partially constructed facilities in the Western U.S.

International Energy develops, operates and manages power generation facilities, and engages in sales and marketing of electric power and natural gas outside the U.S. and Canada. It conducts operations primarily through Duke Energy International, LLC (DEI) and its activities target power generation in Latin America.

During 2003, International Energy began the process to discontinue proprietary trading and is in the process of exiting its European and Australian operations.

Beginning in 2004, Crescent, formerly part of Other Operations, is considered a separate reportable segment. All information for all the years presented within this report has been updated to show the impact of presenting Crescent as a separate reportable segment. Crescent develops high-quality commercial, residential and multi-family real estate projects, and manages legacy land holdings primarily in the Southeastern and Southwestern U.S.

All other entities previously included in Other Operations and now within Other still remain, primarily: DukeNet Communications, LLC (DukeNet), Duke Energy Merchants, LLC (DEM) and Duke/Fluor Daniel (D/FD). DukeNet develops and manages fiber optic communications systems for wireless, local and long-distance communications companies; and for selected educational, governmental, financial and health care entities. DEM is in the refined products business. During 2003, Duke Energy determined that it will exit the refined products business at DEM in an orderly manner, and is unwinding its portfolio of contracts. D/FD provides comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide. D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor Corporation. During 2003, Duke Energy and Fluor Corporation announced that the D/FD partnership will be dissolved. The D/FD partners have adopted a plan for an orderly wind-down of the business targeted for completion in July 2005. Also previously included in Other Operations was Energy Delivery Services, an engineering, construction, maintenance and technical services firm specializing in electric transmission and distribution lines and substation projects, until its sale in December 2003. Additionally, Duke Capital Partners, LLC, a wholly owned merchant finance company that provided debt and equity capital and financial advisory services primarily to the merchant energy industry, had been previously included in Other Operations, but is now classified as discontinued operations.

Duke Energy is a North Carolina corporation. Its principal executive offices are located at 526 South Church Street, Charlotte, North Carolina 28202-1803. The telephone number is 704-594-6200. Duke Energy electronically files reports with the Securities and Exchange Commission (SEC), including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxies and amendments to such reports. The public may read and copy any materials that Duke Energy files with the SEC at the SEC s Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov. Additionally, information about Duke Energy, including its reports filed with the SEC, is available through Duke Energy s web site at http://www.duke-energy.com. Such reports are accessible at no charge through Duke Energy s web site and are made available as soon as reasonably practicable after such material is filed with or furnished to the SEC.

Terms used to describe Duke Energy s business are defined below.

Allowance for Funds Used During Construction. A non-cash accounting convention of regulatory utilities that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

British Thermal Unit (Btu). A standard unit for measuring thermal energy or heat commonly used as a gauge for the energy content of natural gas and other fuels.

Cubic Foot (cf). The most common unit of measurement of gas volume; the amount of natural gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor.

Decommissioning. The process of closing down a nuclear facility and reducing the residual radioactivity to a level that permits the release of the property and termination of the license. Nuclear power plants are required by the Nuclear Regulatory Commission (NRC) to set aside funds for their decommissioning costs during operation.

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Derivative. A contract in which its price is based on the value of underlying securities, equity indices, debt instruments, commodities or other benchmarks or variables. Often used to hedge risk, derivatives involve the trading of rights or obligations, but not the direct transfer of property and gains or losses are often settled net.

Distribution. The system of lines, transformers, switches and mains that connect electric and natural gas transmission systems to customers.

Duke Capital. Duke Capital LLC (formerly known as Duke Capital Corporation), a wholly owned subsidiary of Duke Energy that provides financing and credit enhancement services for its subsidiaries.

Federal Energy Regulatory Commission (FERC). The U.S. agency that regulates the transportation of electricity and natural gas in interstate commerce and authorizes the buying and selling of energy commodities at market-based rates.

Forward Contract. A contract in which the buyer is obligated to take delivery, and the seller is obligated to deliver a fixed amount of a commodity at a predetermined price on a specified future date, at which time payment is due in full.

Fractionation/Fractionate. The process of separating liquid hydrocarbons from natural gas into propane, butane, ethane, etc.

Gathering System. Pipeline, processing and related facilities that access production and other sources of natural gas supplies for delivery to mainline transmission systems.

Generation. The process of transforming other forms of energy, such as nuclear or fossil fuels, into electricity. Also, the amount of electric energy produced, expressed in megawatt-hours.

Independent System Operator (ISO). An entity that ensures non-discriminatory access to a regional transmission system, providing all customers access to the power exchange and clearing all bilateral contract requests for use of the electric transmission system. Also responsible for maintaining bulk electric system reliability.

Light-off Fuel. Fuel oil used to light the coal prior to generating electricity.

Liquefied Natural Gas (LNG). Natural gas that has been converted to a liquid by cooling it to 260 degrees Fahrenheit.

Local Distribution Company (LDC). A company that obtains the major portion of its revenues from the operations of a retail distribution system for the delivery of electricity or gas for ultimate consumption.

Logistics & Optimization. The act of maximizing returns from physical positions through arbitrage, especially on contractual assets such as storage, transportation, generation and transmission.

Mark-to-Market. The process whereby an asset or liability is recognized at fair value and the change in the fair value of that asset or liability is recognized in revenues in the Consolidated Statements of Operations or in Other Comprehensive Income within equity during the current period.

Natural Gas. A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geological formations beneath the earth s surface, often in association with petroleum. The principal constituent is methane.

Natural Gas Liquids (NGLs). Liquid hydrocarbons extracted during the processing of natural gas. Principal commercial NGLs include butanes, propane, natural gasoline and ethane.

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No-notice Bundled Service. A pipeline delivery service which allows customers to receive or deliver gas on demand without making prior nominations to meet service needs and without paying daily balancing and scheduling penalties.

Origination. Identification and execution of physical energy related transactions, generally with customized provisions to meet the needs of the customer or supplier, throughout the value chain.

Peak Load. The amount of electricity required during periods of highest demand. Peak periods fluctuate by season, generally occurring in the morning hours in winter and in late afternoon during the summer.

Regional Transmission Organization (RTO). An independent entity which is established to have functional control over utilities transmission systems, in order to expedite transmission of electricity.

Reliability Must Run. Generation that the California ISO determines is required to be on-line to meet applicable reliability criteria requirements.

Residue Gas. Gas remaining after the processing of natural gas.

Spark Spread. The difference between the value of electricity and the value of the gas required to generate the electricity at a specified heat rate.

Throughput. The amount of natural gas or natural gas liquids transported through a pipeline system.

Tolling. Process whereby a party provides fuel to a power generator and receives kilowatt hours in return for a pre-established fee.

Transmission System (Electric). An interconnected group of electric transmission lines and related equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over a distribution system to customers, or for delivery to other electric transmission systems.

Transmission System (Natural Gas). An interconnected group of natural gas pipelines and associated facilities for transporting natural gas in bulk between points of supply and delivery points to industrial customers, LDCs, or for delivery to other natural gas transmission systems.

Volatility. An annualized measure of the fluctuation in the price of an energy contract. Implied volatility is a measure of what the market values volatility to be, as reflected in the option s price.

Watt. A measure of power production or usage equal to one joule per second.

The following sections describe the business and operations of each of Duke Energy s business segments. (For more information on the operating outlook of Duke Energy and its segments, see Management s Discussion and Analysis of Results of Operations and Financial Condition, Introduction Overview of Business Strategy and Economic Factors. For financial information on Duke Energy s business segments, see Note 3 to the Consolidated Financial Statements, Business Segments.)

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FRANCHISED ELECTRIC

Service Area and Customers

Franchised Electric generates, transmits, distributes and sells electricity. It conducts operations primarily through Duke Power. Its service area covers about 22,000 square miles with an estimated population of 5.9 million in central and western North Carolina and western South Carolina. Franchised Electric supplies electric service to approximately 2.2 million residential, commercial and industrial customers over 92,000 miles of distribution lines and a 13,000 mile transmission system. Electricity is sold wholesale to incorporated municipalities and to public and private utilities. In addition, municipal and cooperative customers who purchased portions of the Catawba Nuclear Station buy power through contractual agreements. (For more information on the Catawba Nuclear Station joint ownership, see Note 5 to the Consolidated Financial Statements, Joint Ownership of Generating Facilities.)

Industrial and commercial development in Franchised Electric s service area is highly diversified. The textile industry, machinery and equipment manufacturing, and chemical industries are of major significance to the area s economy. Other industries operating in the area include rubber and plastic products, paper and related products, and other manufacturing and service businesses. The textile industry, the largest industry served by Franchised Electric, accounted for approximately $309 million of Franchised Electric s revenues for 2003, representing 6% of total electric revenues and 29% of industrial revenues. Franchised Electric normally experiences seasonal peak loads in summer and winter months.

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Energy Capacity and Resources

Electric energy for Franchised Electric s customers is generated by three nuclear generating stations with a combined net capacity of 5,020 megawatts (MW) (including Duke Energy s 12.5% ownership in the Catawba Nuclear Station), eight coal-fired stations with a combined capacity of 7,699 MW, 31 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 2,806 MW and seven combustion turbine stations with a combined capacity of 2,424 MW. Energy and capacity are also supplied through contracts with other generators and purchased on the open market. Franchised Electric has interconnections and arrangements with its neighboring utilities to facilitate planning, emergency assistance, exchange of capacity and energy, and reliability of power supply. Franchised Electric expects that additional construction, purchased power contracts and open market purchases will meet customers energy needs in the future.

Franchised Electric s generation portfolio is a balanced mix of energy resources with different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet its obligation to serve native load customers. All options including owned generation resources and purchased power opportunities are continually evaluated on a real time basis to select and dispatch the lowest cost resources available to meet system load requirements. The vast majority of customer energy needs are met by Franchised Electric s large, low energy production cost nuclear and coal fired generating units that operate almost continuously (or at baseload levels). In 2003, more than 97% of the total generated energy came from Franchised Electric s low cost, efficient nuclear and coal units (46.7% nuclear and 50.7% coal). The remainder of energy needs was supplied by hydro and combustion turbine generation or economical purchases from the wholesale market.

Hydroelectric (both conventional and pumped storage) and gas/oil combustion turbine stations operate during fewer peak hour load periods (or peaking levels) when customer loads are rapidly changing. Combustion turbines produce energy at higher production costs than either nuclear or coal, but are less expensive to build, maintain, and can be rapidly started or stopped as needed to meet changing customer loads. Hydroelectric units produce low cost energy, but their operations are limited by the availability of water flow which increased dramatically in 2003 as compared to the four previous drought years. Since these hydroelectric units can also be rapidly started or stopped, they are also used in peak periods when customer loads are rapidly changing so that system operators can match changing customer loads with the appropriate amount of generation.

Franchised Electric s two major pumped-storage hydroelectric facilities offer the added flexibility of using low cost off-peak energy to pump water that will be stored for later generation use during times of higher cost on-peak generation periods. These plants allow Franchised Electric to maximize the value spreads between different high and low cost generation periods.

Fuel Supply

Franchised Electric relies principally on coal and nuclear fuel for its generation of electric energy. The following table lists Franchised Electric s sources of power and fuel costs for the three years ended December 31, 2003.

	Generation by Source (Percent)			**Cost of Delivered Fuel per Net Kilowatt-hour Generated (Cents)**		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**

Coal	50.7	51.2	50.9	1.59	1.54	1.48
Nuclear(a)	46.7	48.3	48.6	0.42	0.42	0.42
Oil and gas(b)	0.1	0.1	0.2	15.52	11.89	11.48
All fuels (cost based on weighted average)(a)	97.5	99.6	99.7	1.05	1.01	0.98
Hydroelectric(c)	2.5	0.4	0.3			
	100.0	100.0	100.0			

(a) Statistics related to nuclear generation and all fuels reflect Franchised Electric s 12.5% ownership interest in the Catawba Nuclear Station.
(b) Cost statistics include amounts for light-off fuel at Franchised Electric s coal-fired stations.
(c) Generating figures are net of output required to replenish pumped storage facilities during off-peak periods.

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Coal. Franchised Electric meets its coal demand through purchase supply contracts and spot agreements. Large amounts of coal are obtained under supply contracts with mining operators who mine both underground and at the surface. Franchised Electric has an adequate supply of coal to fuel its current operations. Expiration dates for its supply contracts, which have price adjustment provisions, range from 2004 to 2006. Duke Energy expects to renew these contracts or enter into similar contracts with other suppliers for the quantities and quality of coal required, though prices will fluctuate over time. The coal purchased under these contracts is produced from mines in eastern Kentucky, southern West Virginia and southwestern Virginia. Franchised Electric uses spot market purchases to meet coal requirements not met by supply contracts.

The average sulfur content of coal purchased by Franchised Electric is approximately 1%. This coal, coupled with utilization of available sulfur dioxide emission allowances on the open market satisfies the current emission limitation for sulfur dioxide for existing facilities.

Nuclear. Developing nuclear generating fuel generally involves the mining and milling of uranium ore to produce uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride gas, enrichment of that gas, and then the fabrication of the enriched uranium hexafluoride into usable fuel assemblies.

Franchised Electric has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations. Uranium concentrates, conversion services and enrichment services are primarily met through a diversified portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. Franchised Electric staggers its contracting so that its portfolio of long-term contracts covers the majority of its fuel requirements at Oconee, McGuire and Catawba in the near term, but so that its level of coverage decreases each year into the future. Due to the technical complexities of changing suppliers of fuel fabrication services, Franchised Electric generally sole sources these services to domestic suppliers on a plant by plant basis using multi-year contracts.

Based upon current projections, Franchised Electric s existing portfolio of contracts will meet the requirements of Oconee, McGuire and Catawba Nuclear Stations through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	2005	2005	2007	2006
McGuire	2005	2005	2007	2009
Catawba	2005	2005	2007	2009

After the years indicated above, a portion of the fuel requirements at Oconee, McGuire and Catawba are covered by long-term contracts. For requirements not covered under long-term contracts, Duke Energy believes it will be able to renew contracts as they expire, or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with uranium spot market purchases.

Duke Power has entered into a contract under which Duke Power has agreed to prepare the McGuire and Catawba nuclear reactors for use of mixed oxide fuel and to purchase mixed oxide fuel for use in such reactors. Mixed oxide fuel will be fabricated by Duke COGEMA Stone and Webster, LLC from the U.S. government s excess plutonium in its nuclear weapons programs and is similar to conventional uranium fuel. Before using the fuel, Duke Energy must apply for and obtain amendments to the facilities operating licenses from the NRC. (See Note 18 to the Consolidated Financial Statements, Guarantees and Indemnifications, for additional information.)

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Insurance and Decommissioning

Duke Energy owns and operates the McGuire and Oconee Nuclear Stations and operates and has a partial ownership interest in the Catawba Nuclear Station. The McGuire and Catawba Nuclear Stations have two nuclear reactors each and Oconee has three. Nuclear insurance includes: liability coverage; property, decontamination and decommissioning coverage; and business interruption and/or extra expense coverage. The other joint owners of the Catawba Nuclear Station reimburse Duke Energy for certain expenses associated with nuclear insurance premiums. The Price-Anderson Act requires Duke Energy to insure against public liability claims resulting from nuclear incidents to the full limit of liability, approximately $10.9 billion. (See Note 17 to the Consolidated Financial Statements, Commitments and Contingencies Nuclear Insurance, for more information.)

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.9 billion in 1999 dollars, based on decommissioning studies completed in 1999 (studies are completed every five years). This includes costs related to Duke Energy s 12.5% ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Both the NCUC and the PSCSC have allowed Duke Energy to recover estimated decommissioning costs through rates over the expected remaining service periods of Duke Energy s nuclear stations.

After spent fuel is removed from a nuclear reactor, it is cooled in a spent fuel pool at the nuclear station. Under provisions of the Nuclear Waste Policy Act of 1982, Duke Energy has contracted with the U.S. Department of Energy (DOE) for the disposal of spent nuclear fuel. The DOE failed to begin accepting spent nuclear fuel on January 31, 1998, the date specified by the Nuclear Waste Policy Act and in Duke Energy s contract with the DOE. In 1998, Duke Energy filed a claim with the U.S. Court of Federal Claims against the DOE related to the DOE s failure to accept commercial spent nuclear fuel by the required date. Damages claimed in the lawsuit are based upon Duke Energy s costs incurred as a result of the DOE s partial material breach of its contract, including the cost of securing additional spent fuel storage capacity. Duke Energy will continue to safely manage its spent nuclear fuel until the DOE accepts it. Payments made to the DOE for disposal costs are based on nuclear output and are included in the Consolidated Statements of Operations as Fuel Used in Electric Generation and Purchased Power.

Competition

Duke Energy continues to monitor electric industry restructuring; however, movement toward retail deregulation has virtually stopped. (For more information, see Management s Discussion and Analysis of Results of Operations and Financial Condition, Current Issues Electric Competition.)

Franchised Electric competes in some areas with government-owned power systems, municipally owned electric systems, rural electric cooperatives and other private utilities. By statute, the NCUC and the PSCSC assign all service areas outside municipalities in North Carolina and South Carolina to regulated electric utilities and rural electric cooperatives. Substantially all of the territory comprising Franchised Electric s service area has been assigned in this manner. In unassigned areas, Franchised Electric s business remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina, competition continues between municipalities and other electric suppliers outside the municipalities corporate limits, subject to the regulation of the PSCSC. In addition, Franchised Electric continues to compete with natural gas providers.

Regulation

The NCUC and the PSCSC approve rates for retail electric sales within their respective states. The FERC approves Franchised Electric s rates for some electric sales to wholesale customers, excluding the other joint owners of the Catawba Nuclear Station: those rates are set through contractual agreements. (For more

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information on rate matters, see Note 4 to the Consolidated Financial Statements, Regulatory Matters Franchised Electric.) The FERC, the NCUC and the PSCSC also have authority over the construction and operation of Franchised Electric s facilities. Certificates of public convenience and necessity issued by the FERC, the NCUC and the PSCSC authorize Franchised Electric to construct and operate its electric facilities, and to sell electricity to retail and wholesale customers. Prior approval from the NCUC and the PSCSC is required for Duke Energy to issue securities.

NCUC, PSCSC and FERC regulations govern access to regulated electric customer and other data by non-regulated entities, and services provided between regulated and non-regulated affiliated entities. These regulations affect the activities of non-regulated affiliates with Franchised Electric.

The Energy Policy Act of 1992 and the FERC s subsequent rulemaking activities opened the wholesale energy market to competition. Open-access transmission for wholesale customers, as defined by the FERC s rules, provides energy suppliers, including Duke Energy, with opportunities to sell and deliver capacity and energy at market-based prices. From the FERC s open-access rule, Franchised Electric obtained the rights to sell capacity and energy at market-based rates from its own assets, which also allows Franchised Electric to purchase, at attractive rates, a portion of its capacity and energy requirements resulting in lower overall costs to customers. Open access also provides Franchised Electric s existing wholesale customers with competitive opportunities to seek other suppliers for their capacity and energy requirements.

In 1999 and 2000, the FERC issued its Order 2000 and Order 2000-A regarding RTOs. These orders set minimum characteristics and functions RTOs must meet, including independent authority to establish the terms and conditions of transmission service over the facilities they control. The orders provide for an open and flexible RTO structure to meet the needs of the market, and for the possibility of incentive ratemaking and other benefits for transmission owners that participate. The FERC proposes to have RTOs or other independent transmission providers operate transmission systems in all regions of the country.

As a result of these rulemakings, Duke Power and the franchised electric units of two other investor-owned utilities, Carolina Power & Light Company and South Carolina Electric & Gas Company, planned to establish GridSouth Transco, LLC (GridSouth), as an RTO responsible for the functional control of the companies combined transmission systems. As of December 31, 2003, Duke Energy had invested $41 million in GridSouth, including carrying costs calculated through December 31, 2002. This amount is included in Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets. The sponsors expected that GridSouth would be substantially operational by the FERC s Order 2000 deadline date of December 15, 2001. However, in July 2001 the FERC ordered GridSouth and other utilities in the Southeast to join in a mediation to negotiate terms of a southeastern RTO. It does not appear that the FERC will issue an order specifically based on that proceeding. In 2002, the GridSouth sponsors withdrew their applications to the NCUC and the PSCSC for approval of the transfer of functional control of their electric transmission assets to GridSouth, and announced that development of the GridSouth implementation project had been suspended until the sponsors have an opportunity to further consider regulatory circumstances. Duke Energy believes that more open wholesale electric markets will at some point provide benefits to consumers and other market participants. Duke Energy continues to examine options relative to RTOs in light of the existing complex regulatory environment. Management expects it will recover its investment in GridSouth.

Franchised Electric is subject to the NRC jurisdiction for the design, construction and operation of its nuclear generating facilities. In 2000, the NRC renewed the operating license for Duke Energy s three Oconee nuclear units through 2033 and 2034. In 2003, the NRC renewed the operating licenses for all units at Duke Energy s McGuire and Catawba stations. The two McGuire units are licensed through 2041 and 2043, while the two Catawba units are licensed through 2043. Franchised Electric s hydroelectric generating facilities are licensed by the FERC under Part I of the Federal Power Act, with license terms expiring from 2005 to 2036. The FERC has authority to extend hydroelectric generating licenses. Other hydroelectric facilities whose licenses expire between 2005 and 2008 are in various stages of relicensing.

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Franchised Electric is subject to the jurisdiction of the Environmental Protection Agency (EPA) and state environmental agencies. (For a discussion of environmental regulation, see Environmental Matters in this section.)

NATURAL GAS TRANSMISSION

Natural Gas Transmission provides transportation and storage of natural gas for customers throughout the East Coast and Southern U.S., the Pacific Northwest, and in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and gas transportation and processing services to customers in Western Canada. Natural Gas Transmission does business primarily through Duke Energy Gas Transmission Corporation.

For 2003, Natural Gas Transmission s proportional throughput for its pipelines totaled 3,362 trillion British thermal units (TBtu), compared to 3,160 TBtu in 2002, a 6% increase mainly due to the Westcoast Energy Incorporated (Westcoast) acquisition. This includes throughput on Natural Gas Transmission s wholly owned U.S. and Canadian pipelines and its proportional share of throughput on pipelines that are not wholly owned. The operations purchased in the Westcoast acquisition contributed 1,396 TBtu in 2003, compared to 1,229 TBtu in 2002. A majority of Natural Gas Transmission s contracted transportation volumes are under long-term firm service agreements with LDC customers in the pipelines market areas. Firm transportation services are also provided to gas marketers, producers, other pipelines, electric power generators and a variety of end-users. In addition, the pipelines provide both firm and interruptible transportation to various customers on a short-term or seasonal basis. Demand on Natural Gas Transmission s pipeline systems is seasonal, with the highest throughput occurring during colder periods in the first and fourth calendar quarters. Natural Gas Transmission s pipeline systems consist of more than 17,500 miles of transmission pipelines. The pipeline systems receive natural gas from major North American producing regions for delivery to markets primarily in the Mid-Atlantic, New England and Southeastern states, Ontario, British Columbia, and the Pacific Northwest. (For detailed descriptions of Natural Gas Transmission s pipeline systems, see Properties Natural Gas Transmission)

Natural Gas Transmission provides retail distribution services through its subsidiary, Union Gas Limited (Union Gas). Union Gas owns and operates natural gas transmission, distribution and storage facilities in Ontario. Union Gas distributes natural gas to customers in northern, southwestern and eastern Ontario and provides storage, transportation and related services to utilities and other industry participants in the gas markets of Ontario, Quebec and the Central and Eastern U.S. Union Gas distribution service area extends throughout northern Ontario from the Manitoba border to the North Bay/Muskoka area, through southern Ontario from Windsor to just west of Toronto, and across eastern Ontario from Port Hope to Cornwall. Union Gas distribution system consists of approximately 21,000 miles of distribution pipelines serving approximately 1.2 million residential, commercial and industrial customers.

Natural Gas Transmission, through Market Hub Partners (MHP), wholly owns natural gas salt cavern facilities in south Texas and Louisiana with a total storage capacity of approximately 31 billion cubic feet (Bcf). MHP markets natural gas storage services to pipelines, LDCs, producers, end users and natural gas marketers. Texas Eastern Transmission, LP (Texas Eastern) and East Tennessee Natural Gas Company (ETNG) also provide firm and interruptible open-access storage services. Storage is offered as a stand-alone unbundled service or as part of a no-notice bundled service with transportation. Texas Eastern has two joint-venture storage facilities in Pennsylvania and one wholly owned and operated storage field in Maryland. Texas Eastern s certificated working capacity in these three fields is 75 Bcf. ETNG has an LNG storage facility in Tennessee with a certificated working capacity of 1.2 Bcf. Union Gas owns approximately 150 Bcf of natural gas storage capacity in 20 underground facilities located in depleted gas fields near Sarnia, Ontario.

Competition

Natural Gas Transmission s pipeline, storage and gas gathering and processing businesses compete with other pipeline and storage facilities in the transportation, processing and storage of natural gas. Natural Gas Transmission competes directly with other pipelines and storage facilities serving its market areas. Natural Gas Transmission also competes directly with other natural gas storage facilities in south Texas, Louisiana and Ontario. The principal elements of competition are rates, terms of service, and flexibility and reliability of service.

Natural gas competes with other forms of energy available to Natural Gas Transmission s customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors affect the demand for natural gas in the areas served by Natural Gas Transmission.

Union Gas distribution sales to industrial customers are affected by weather, economic conditions and the price of competitive energy sources. Most of Union Gas industrial and commercial customers, and a portion of residential customers, purchase their natural gas supply directly from suppliers or marketers. As Union Gas earns income from the distribution of natural gas and not the sale of the natural gas commodity, the gas distribution margin is not affected by the source of the customer s gas supply.

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Regulation

Most of Natural Gas Transmission s pipeline and storage operations in the U.S. are regulated by the FERC. The FERC has authority to regulate rates and charges for natural gas transported or stored for U.S. interstate commerce or sold by a natural gas company via interstate commerce for resale. (For more information on rate matters, see Note 4 to the Consolidated Financial Statements, Regulatory Matters Natural Gas Transmission.) The FERC also has authority over the construction and operation of U.S. pipelines and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. In addition, certain operations are subject to state regulatory commissions.

The FERC regulations restrict access to U.S. interstate pipeline natural gas transmission customer and other data by affiliated gas marketing entities, and place certain conditions on services provided by the U.S. interstate pipelines to their affiliated gas marketing entities. These regulations affect the activities of non-regulated affiliates with Natural Gas Transmission.

Natural Gas Transmission s U.S. operations are subject to the jurisdiction of the EPA and state environmental agencies. (For a discussion of environmental regulation, see Environmental Matters in this section.) Natural Gas Transmission s interstate natural gas pipelines are subject to the regulations of the DOT concerning pipeline safety. DOT regulations have incorporated certain provisions of the Natural Gas Pipeline Safety Act of 1968 (and subsequent acts). The DOT has developed new regulations, effective February 14, 2004, that establish mandatory inspections for all natural gas transmission pipelines in high-consequence areas within 10 years. The new regulations require pipeline operators to implement integrity management programs, including more frequent inspections, and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to life and property. Management believes that compliance with these new DOT regulations for Natural Gas Transmission will not have a material adverse effect on the consolidated results of operations, cash flows or financial position of Duke Energy.

The natural gas gathering, processing, transmission, storage and distribution operations in Canada are subject to regulation by the NEB and provincial agencies in Canada, such as the OEB and the British Columbia Utilities Commission. These agencies have authorization similar to the FERC for setting rates, regulating the operations of facilities and construction of any additional facilities.

FIELD SERVICES

Field Services gathers, compresses, treats, processes, transports, trades and markets, and stores natural gas; and produces, transports, trades and markets, and stores NGLs. It conducts operations primarily through DEFS, which is approximately 30% owned by ConocoPhillips and approximately 70% owned by Duke Energy. Field Services gathers natural gas from production wellheads in Western Canada and ten states in the U.S. Those systems serve major gas-producing regions in the Western Canadian Sedimentary Basin, Rocky Mountain, Permian Basin, Mid-Continent and East Texas-Austin Chalk-North Louisiana areas, as well as onshore and offshore Gulf Coast areas. Field Services owns and operates approximately 58,000 miles of natural gas gathering systems with approximately 34,000 active receipt points.

Field Services natural gas processing operations separate raw natural gas that has been gathered on its systems and third-party systems into condensate, NGLs and residue gas. Field Services processes the raw natural gas at the 56 natural gas processing facilities that it owns and operates and at ten third-party operated facilities in which it has an equity interest.

The NGLs separated from the raw natural gas are either sold and transported as NGL raw mix, or further separated through a fractionation process into their individual components (ethane, propane, butanes and natural gasoline) and then sold as components. Field Services fractionates NGL raw mix at ten processing facilities that it owns and operates and at four third-party-operated facilities in which it has an equity interest. In addition, Field

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Services operates a propane wholesale marketing business. Field Services sells NGLs to a variety of customers ranging from large, multinational petrochemical and refining companies to small regional retail propane distributors. Substantially all of its NGL sales are at market-based prices.

The residue gas separated from the raw natural gas is sold at market-based prices to marketers or end-users, including large industrial customers and natural gas and electric utilities serving individual consumers. Field Services markets residue gas directly or through its wholly owned gas marketing company and its affiliates. Field Services also stores residue gas at its 6 Bcf natural gas storage facility.

Field Services uses NGL trading and storage at the Mont Belvieu, Texas and Conway, Kansas NGL market centers to manage its price risk and to provide additional services to its customers. Asset based gas trading and marketing activities are supported by ownership of the Spindletop storage facility and various intrastate pipelines which provide access to market centers/hubs such as Waha, Texas; Katy, Texas and the Houston Ship Channel. Field Services undertakes these NGL and gas trading activities through the use of fixed forward sales, basis and spread trades, storage opportunities, put/call options, term contracts and spot marketing trading. Field Services believes there are additional opportunities to grow its services with its customer base.

The following map includes Field Services natural gas gathering systems, intrastate pipelines, regional offices and supply areas. The map also shows Natural Gas Transmission s interstate pipeline systems.

Field Services also owns Texas Eastern Products Pipeline Company, LLC (TEPPCO), the general partner of TEPPCO Partners, L.P., a publicly traded limited partnership which owns one of the largest common carrier pipelines of refined petroleum products and liquefied petroleum gases in the U.S., as well as, natural gas gathering systems, petrochemical and natural gas liquid pipelines, and is engaged in crude oil transportation, storage, gathering and marketing. TEPPCO is responsible for the management and operations of TEPPCO Partners, L.P.

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Field Services operating results are significantly impacted by changes in average NGL prices, which increased approximately 39% in 2003 compared to 2002. (See Management s Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk for a discussion of Field Services exposure to changes in commodity prices.)

Field Services activities can fluctuate in response to seasonal demand for natural gas.

Competition

Field Services competes with major integrated oil companies, major interstate and intrastate pipelines, national and local natural gas gatherers, and brokers, marketers and distributors for natural gas supplies, in gathering and processing natural gas and in marketing and transporting natural gas and NGLs. Competition for natural gas supplies is based primarily on the reputation, efficiency and reliability of operations, the availability of gathering and transportation to high-demand markets, the pricing arrangement offered by the gatherer/processor and the ability of the gatherer/processor to obtain a satisfactory price for the producer s residue gas and extracted NGLs; whereas, competition for sales to customers is based primarily upon reliability, services offered, and price of delivered natural gas and NGLs.

Regulation

The intrastate pipelines owned by Field Services are subject to state regulation. To the extent they provide services under Section 311 of the Natural Gas Policy Act of 1978, the pipelines are also subject to FERC regulation. However, most of Field Services natural gas gathering activities are not subject to FERC regulation.

Field Services is subject to the jurisdiction of the EPA and state environmental agencies. (For more information, see Environmental Matters in this section.) Some of Field Services operations are subject to the jurisdiction of the Federal and state transportation agencies.

Recently, the DOT has developed new regulations, effective February 14, 2004, that require gas transmission pipeline operators to develop and implement integrity management programs for gas transmission pipelines located where a leak or rupture could have the greatest impact to life and property in areas referred to as high consequence areas. The regulations require gas pipeline transmission operators to perform ongoing assessments of pipeline integrity and to implement preventative and mitigative actions. Baseline integrity assessments are required to be completed by December 2012. Reassessments are to be conducted at prescribed intervals. Field Services is presently developing its implementation program to address these new DOT requirements, and is also evaluating the effects of complying with this new DOT regulatory program.

Field Services Canadian assets are regulated by the Alberta Energy and Utilities Board and the NEB.

DUKE ENERGY NORTH AMERICA

DENA operates and manages merchant power generation facilities and engages in commodity sales and services related to natural gas and electric power around its generation and contractual positions. DENA conducts business throughout the U.S. and Canada through Duke Energy North America and DETM. DETM is 40% owned by Exxon Mobil Corporation and 60% owned by Duke Energy. As discussed below, during 2003 certain key events led DENA to undertake a number of actions to change its existing business strategy.

As an active participant in the North American wholesale energy market, DENA has redefined its business strategy primarily in response to:

- Power generation oversupply in certain regions in the U.S., resulting in low spark spreads

- Reduction of major wholesale energy marketing and trading participants resulting in decreased market liquidity and increased collateral demands

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As a result of these market developments DENA:

- Executed substantial re-organization efforts, resulting in significant staff and annual cost reductions
- Discontinued proprietary trading and other non-core businesses
- Decided to exit the Southeast region
- Resolved to wind down the operations of DETM. The majority of the commodity contracts have been eliminated or sold to third parties. DENA will continue its participation in the market through 100% Duke Energy-owned entities.

In the fourth quarter 2003, management decided to: a) exit the Southeast region through a contemplated disposition of its merchant generation plants located in that region, b) not use Duke Energy funds to complete construction and reduce DENA s interest in deferred plants, and c) wind-down DETM. These actions negatively impacted operating income by approximately $3.1 billion.

Previously, DETM was committed to market substantially all of ExxonMobil s U.S. and Canadian natural gas production through 2006. Beginning in March 2003, most of this natural gas production was no longer made available to be marketed by DETM. This change in gas supply along with the other key market events described above prompted the wind-down of DETM. As stated above, the majority of DETM s commodity contracts have been eliminated or sold to third parties during 2003 and the remaining actions to wind-down DETM s operations will continue in 2004.

In June 2003, DENA sold its 50% ownership interest in Duke/UAE Ref-Fuel for $325 million to Highstar Renewable Fuels LLC. DENA recorded a gain on the sale of approximately $178 million, which is included in Gains on Sales of Equity Investments in the Consolidated Statements of Operations.

Generation Assets

DENA currently owns or operates approximately 15,820 net MW of operating generation and has approximately 2,402 net MW of operating generation under construction. During 2003, DENA determined that the partially constructed power generation facilities, Moapa, Grays Harbor, and Luna (collectively the deferred plants), will not be completed with Duke Energy funds. DENA will look to sell and/or solicit funding for completion of the deferred plants in 2004. Additionally, DENA has decided to sell all of its power generation facilities in the Southeast U.S.

The following map shows DENA s power generation facilities.

Marketing Portfolio

The majority of DENA s portfolio of purchase and sales agreements incorporate market-sensitive pricing terms. Physical purchase and sales commitments involving significant price and location risk are generally hedged with financial derivatives. DENA s results may also fluctuate in response to seasonal demand for electricity, natural gas and other energy-related commodities. Additionally, weather has a significant impact on electricity and natural gas demand. (For information concerning DENA s risk-management activities, see Management s Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk and Note 8 to the Consolidated Financial Statements, Risk Management and Hedging Activities, Credit Risk and Financial Instruments.)

Customers

DENA markets electricity to investor-owned utilities, municipal power generators and other power marketers. DENA markets natural gas primarily to LDCs, electric power generators, municipalities, large industrial end-users and energy marketing companies. DENA also provides energy management services, such as supply and market aggregation, peaking services, dispatching, balancing, transportation, storage, tolling, contract negotiation and administration, as well as energy commodity risk management products and services.

Competition

DENA s competitors include utilities, other merchant electric generation companies in North America, certain financial institutions engaged in commodity trading, major integrated oil companies, major interstate pipelines and their marketing affiliates, brokers, marketers and distributors, and other domestic and international electric power and natural gas marketers. The price of commodities and services delivered, along with the quality and reliability of services provided, drive competition in the energy marketing business.

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Over the past two years, there has been a significant reduction in number of market participants due to the profitability decline resulting from oversupply of generation, increase in regulation, cost of capital to maintain generation facilities, collateral requirements, and bankruptcies. With fewer market participants, liquidity has been further depressed.

Regulation

DENA s energy marketing activities are, in some circumstances, subject to the jurisdiction of the FERC. Current FERC policies permit DENA s trading and marketing entities to market natural gas, electricity and other energy-related commodities at market-based rates, subject to FERC jurisdiction. DENA continues to monitor the varied pace of wholesale electricity market restructuring. (For more information, see Management s Discussion and Analysis of Results of Operations and Financial Condition, Current Issues Electric Competition.)

Certain of DENA s generating stations in California sell electricity to the California ISO under reliability must run agreements; those sales are made at FERC regulated rates. In addition, several legal and regulatory proceedings at the state and federal levels are ongoing related to DENA s activities in California during the electricity supply situation and related to trading activities. (See Note 17 to the Consolidated Financial Statements, Commitments and Contingencies Litigation for further discussion.)

The operation and maintenance of DENA s power plants in California will be subject to regulation pursuant to rules that are currently being promulgated by state authorities. The new rules are intended to increase the reliability of the generation supply in California by setting maintenance standards and regulating when plants may be taken out of service for routine maintenance. Duke Energy does not believe that the new rules, when finalized, will have a material impact on the operation of its power plants in California.

DENA is subject to the jurisdiction of the EPA and state environmental agencies. (For a discussion of environmental regulation, see Environmental Matters in this section.)

INTERNATIONAL ENERGY

International Energy develops, operates and manages power generation facilities, and engages in sales and marketing of electric power and natural gas outside the U.S. and Canada. It conducts operations primarily through DEI and its activities target power generation in Latin America.

During 2003, International Energy sold its interest in P.T. Puncakjaya Power in Indonesia as well as decided to exit the European market and sell its Australian assets. As a result, these operations are not included in International Energy s results but have been reclassified to discontinued operations for current and prior years. As of December 31, 2003, the European and Australian assets and liabilities are classified as Assets Held for Sale, and Liabilities Associated with Assets Held for Sale, respectively, on the Consolidated Balance Sheet. (See Note 12 to the Consolidated Financial Statements, Assets Held for Sale and Discontinued Operations for further discussion.)

From its platform of assets, International Energy provides customers with energy supply at competitive prices, manages the logistics associated with power and natural gas delivery, and offers services that allow customers to improve energy efficiency and hedge their commodity price exposure. International Energy s customers include retail distributors, electric utilities, independent power producers and large industrial companies. International Energy is committed to building integrated regional businesses that provide customers with a full range of innovative and competitively priced energy services.

International Energy s current strategy is focused on maximizing the returns and cash flow from its current portfolio of energy businesses by creating organic growth through its sales and marketing efforts in all regions in which it currently does business, optimizing the output and efficiency of its various facilities, controlling and reducing costs and divesting selected assets.

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International Energy s continuing operations owns, operates or has substantial interests in approximately 4,121 net MW of generation facilities. The following map shows the locations of International Energy s facilities, including projects under construction. The capacities shown in the map are gross MW values (for net MW values see Properties International Energy).

Competition and Regulation

International Energy s sales and marketing of electric power and natural gas competes directly with other generators and marketers serving its market areas. Competitors are country and region-specific but include government owned electric generating companies, LDC s with self-generation capability and other privately owned electric generating companies. The principal elements of competition are price and availability, terms of service, flexibility and reliability of service.

A high percentage of International Energy s portfolio is base-load hydro electric generation facilities which compete with other forms of electric generation available to International Energy s customers and end-users, including natural gas and fuel oils. Economic activity, conservation, legislation, governmental regulations, weather and other factors affect the supply and demand for electricity in the regions served by International Energy.

International Energy s operations are subject to international environmental regulations. (See Environmental Matters in this section.)

CRESCENT

Beginning in 2004, Crescent, formerly part of Other Operations, is considered a separate reportable segment. Crescent develops high-quality commercial, residential and multi-family real estate projects, and manages land holdings, primarily in the Southeastern and Southwestern U.S. On December 31, 2003, Crescent owned 1.3 million square feet of commercial, industrial and retail space, with an additional 0.9 million square

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feet under construction. This portfolio included 1.4 million square feet of office space, 0.4 million square feet of warehouse space and 0.4 million square feet of retail space. Crescent s residential developments include high-end country club and golf course communities, with individual lots sold to custom builders and tract developments sold to national builders. Crescent had four multi-family communities at December 31, 2003, including two operating properties and two properties under development. On December 31, 2003, Crescent also managed approximately 134,000 acres of land.

Competition and Regulation

Crescent competes with multiple regional and national real estate developers across its various business lines in the Southeastern and Southwestern U.S. Crescent s residential division sells developed lots to regional and national home builders and retail buyers, competing with other developers and home builders with an inventory of developed lots. Crescent s commercial division leases office, industrial and retail space, competing with other public and private developers and owners of commercial property, including national real estate investment trusts (REITs). Similarly, Crescent s multi-family division leases apartment units primarily to individuals, competing with other private developers and multi-family REITs.

Crescent is subject to the jurisdiction of the EPA and state and local environmental agencies. (For a discussion of environmental regulation, see Environmental Matters in this section.)

OTHER

Beginning in 2004, with the exception of Crescent, all other entities previously part of Other Operations as defined in Duke Energy s Form 10-K for December 31, 2003 and now within Other, still remain, primarily: DukeNet, DEM and D/FD. Unallocated corporate costs are also included in Other.

DukeNet provides telecommunications bandwidth capacity for industrial and commercial customers through its fiber optic network. It owns and operates a fiber optic communications network centered in North Carolina and South Carolina and is interconnected with a fiber optic communications network through affiliate agreements with third parties.

DEM engages in commodity buying and selling, and risk management and financial services in non-regulated energy commodity markets other than physical natural gas and power (such as petroleum products). DEM s activities can fluctuate in response to seasonal demand for other energy-related commodities. In 2003, Duke Energy determined that it will exit the refined products and NGL business at DEM in an orderly manner. DEM expects to complete the exit during 2004. The exiting process will include both a wind down of the current business and the selling of remaining long-term contracts. In 2003, DEM also sold Duke Energy Hydrocarbons LLC, and the related hydrocarbons activity was classified as discontinued operations.

D/FD, operating through several entities, provides full-service siting, permitting, licensing, engineering, procurement, construction, start-up, operating and maintenance services for fossil-fueled electric power plants, both domestically and internationally. Subsidiaries of Duke Energy and Fluor Corporation each own 50% of D/FD. In 2003, Duke Energy and Fluor Corporation announced that the D/FD partnership will be dissolved. The partners of D/FD have adopted a plan for an orderly wind-down of the D/FD business targeted for completion in July 2005.

Competition and Regulation

DEM competes for other energy-related commodities. Competitors include major integrated oil companies, major interstate pipelines and their marketing affiliates, brokers and distributors. D/FD competes with major companies who provide engineering, procurement, construction, start-up and maintenance services for fossil fueled power generation facilities.

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The entities within Other are subject to the jurisdiction of the EPA and international, state and local environmental agencies. (For a discussion of environmental regulation, see Environmental Matters in this section.)

ENVIRONMENTAL MATTERS

Duke Energy is subject to international, federal, state and local regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental matters. Environmental regulations affecting Duke Energy include, but are not limited to:

- The Clean Air Act and the 1990 amendments to the Act, as well as state laws and regulations impacting air emissions, including State Implementation Plans related to existing and new national ambient air quality standards for ozone and particulate matter. Owners and/or operators of air emissions sources are responsible for obtaining permits and for annual compliance and reporting.
- The Federal Water Pollution Control Act which requires permits for facilities that discharge treated wastewater into the environment.
- The Comprehensive Environmental Response, Compensation and Liability Act, which can require any individual or entity that may have owned or operated a disposal site, as well as transporters or generators of hazardous substances sent to such site, to share in remediation costs.
- The Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, which requires certain solid wastes, including hazardous wastes, to be managed pursuant to a comprehensive regulatory regime.
- The National Environmental Policy Act, which requires consideration of potential environmental impacts by federal agencies in their decisions, including siting approvals.

(For more information on environmental matters involving Duke Energy, including possible liability and capital costs, see Note 17 to the Consolidated Financial Statements, Commitments and Contingencies Environmental.)

Except to the extent discussed in Note 4 and Note 17 to the Consolidated Financial Statements, compliance with international, federal, state and local provisions regulating the discharge of materials into the environment, or otherwise protecting the environment, is not expected to have a material adverse effect on the competitive position, consolidated results of operations, cash flows or financial position of Duke Energy.

GEOGRAPHIC REGIONS

For a discussion of Duke Energy s foreign operations and the risks associated with them, see Management s Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk Foreign Currency Risk, and Notes 3 and 8 to the Consolidated Financial Statements, Business Segments and Risk Management and Hedging Activities, Credit Risk and Financial Instruments.

EMPLOYEES

On December 31, 2003, Duke Energy had approximately 23,800 employees. A total of 3,124 operating and maintenance employees were represented by unions. This amount consists of the following:

1,214 employees represented by the International Brotherhood of Electrical Workers

1,039 employees represented by the Communications, Energy and Paperworkers of Canada

219 employees represented by the United Steel Workers of America

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186 employees represented by the Canadian Pipeline Employees Association

85 employees represented by Sindicato de Trabajadores del Sector Petroquimico

79 employees represented by Sindicato de Trabajadores del Sector Electrico

77 employees represented by Sindicato dos Trabalhadores na Industria da Energia Hidroeletrica de Ipaussu

63 employees represented by the International Union of Operating Engineers

29 employees represented by Asociacion del Personal Jerarquico del Agua y la Energia

25 employees represented by Sindicato Unico de Centrales de Generacion Canion del Pato

24 employees represented by Sindicato dos Trabalhadores na Industria de Energia Eletrica de Campinas

24 employees represented by Sindicato Unico de Generacion Electrica Carhuaquero

20 employees represented by Sindicato Corani

14 employees represented by Federacion Argentina de Trabajadores de Luz y Fuerza

11 employees represented by Sindicato dos Trabalhadores nas Industrias de Energia Eletrica de Sao Paulo

11 employees represented by the National Distribution Union

4 employees represented by the United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industries of the U.S. and Canada

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EXECUTIVE OFFICERS OF DUKE ENERGY

PAUL M. ANDERSON, 58, Chairman of the Board and Chief Executive Officer. Mr. Anderson was named to his current position in November 2003. Mr. Anderson most recently served as Managing Director and Chief Executive Officer of BHP Billiton Ltd and BHP Billiton PLC, from which he retired in July 2002. Prior to joining BHP, Mr. Anderson had a career that spanned more than 20 years at Duke Energy and its predecessor companies, including serving as CEO of PanEnergy Corp (PanEnergy).

KEITH G. BUTLER, 43, Vice President and Controller. Mr. Butler was named Senior Vice President and Chief Financial Officer of Duke Energy Global and its affiliated companies in February 1998, Senior Vice President and Chief Financial Officer of Duke Energy North America in July 1998, and Chief Operating Officer of DukeSolutions in September 1999 before he assumed his current position in August 2001.

MYRON L. CALDWELL, 46, Vice President and Treasurer. Mr. Caldwell was named to his current position in December 2003. He previously served as Vice President of corporate finance since October 2000, and managing director of corporate finance since September 1999. Mr. Caldwell held various other positions since joining Duke Energy in 1981, including Controller of Duke Power and Senior Vice President and Chief Financial Officer of Duke Engineering & Services.

FRED J. FOWLER, 58, President and Chief Operating Officer. Mr. Fowler assumed his current position in November 2002. Mr. Fowler served as Group Vice President of PanEnergy from 1996 until the PanEnergy merger in 1997, when he was named Group President, Energy Transmission.

DAVID L. HAUSER, 52, Group Vice President and Chief Financial Officer. Mr. Hauser assumed his current position in February 2004, but had been the Acting Chief Financial Officer since December 2003. He previously served as Senior Vice President and Treasurer. Mr. Hauser held various positions, including Controller, at Duke Power before being named Senior Vice President, Global Asset Development in 1997.

JIM W. MOGG, 55, Group Vice President and Chief Development Officer. Mr. Mogg assumed his current position in January 2004. He previously served as President and Chief Executive Officer of DEFS since December 1994 and Chairman, President and Chief Executive Officer of DEFS since 1999.

RICHARD J. OSBORNE, 53, Group Vice President, Public and Regulatory Policy. Mr. Osborne assumed his current position in January 2004. He previously served as Executive Vice President and Chief Risk Officer. He also served as Executive Vice President and Chief Financial Officer since 1997 and Senior Vice President and Chief Financial Officer since 1994.

RUTH G. SHAW, 56, President, Duke Power. Dr. Shaw assumed her current position in February 2003. Dr. Shaw served as Senior Vice President, Corporate Resources, from 1994 until the PanEnergy merger in 1997, when she was named Executive Vice President and Chief Administrative Officer.

MARTHA B. WYRSCH, 46, Group Vice President, General Counsel and Secretary. Ms. Wyrsch was named to her current position in January 2004. She previously served as Senior Vice President of Legal Affairs. Ms. Wyrsch joined Duke Energy in September 1999 as Senior Vice President, General Counsel and Secretary for DEFS.

Executive officers are elected annually by the Board of Directors. They serve until the first meeting of the Board of Directors following the annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers, nor any arrangement or understanding between any executive officer and any other person involved in officer selection.

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Item 2. Properties.

FRANCHISED ELECTRIC

As of December 31, 2003, Franchised Electric operated three nuclear generating stations with a combined net capacity of 5,020 MW (including a 12.5% ownership in the Catawba Nuclear Station), eight coal-fired stations with a combined capacity of 7,699 MW, 31 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 2,806 MW and seven combustion turbine stations with a combined capacity of 2,424 MW. All of the stations are located in North Carolina or South Carolina.

Name	Gross MW	Net MW	Fuel	Location	Ownership Interest (percentage)
Oconee	2,538	2,538	Nuclear	SC	100%
Catawba	2,258	282	Nuclear	SC	12.5
Belews Creek	2,240	2,240	Coal	NC	100
McGuire	2,200	2,200	Nuclear	NC	100
Marshall	2,090	2,090	Coal	NC	100
Lincoln CT	1,267	1,267	Natural gas/Fuel Oil	NC	100
Allen	1,140	1,140	Coal	NC	100
Bad Creek	1,065	1,065	Hydro	SC	100
Cliffside	760	760	Coal	NC	100
Jocassee	610	610	Hydro	SC	100
Riverbend	454	454	Coal	NC	100
Lee	370	370	Coal	SC	100
Buck	369	369	Coal	NC	100
Cowans Ford	325	325	Hydro	NC	100
Mill Creek CT	573	573	Natural gas/Fuel Oil	SC	100
Dan River	276	276	Coal	NC	100
Buzzard Roost CT	196	196	Natural gas/Fuel Oil	SC	100
Keowee	160	160	Hydro	SC	100
Riverbend CT	120	120	Natural gas/Fuel Oil	NC	100
Buck CT	93	93	Natural gas/Fuel Oil	NC	100
Lee CT	90	90	Natural gas/Fuel Oil	SC	100
Dan River CT	85	85	Natural gas/Fuel Oil	NC	100
Other small hydro (27 plants)	646	646	Hydro	NC/SC	100
Total	19,925	17,949			

In addition, Franchised Electric owned, as of December 31, 2003, approximately 13,000 conductor miles of electric transmission lines, including 600 miles of 525 kilovolts, 2,600 miles of 230 kilovolts, 6,600 miles of 100 to 161 kilovolts, and 3,200 miles of 13 to 66 kilovolts. Franchised Electric also owned approximately 92,600 conductor miles of electric distribution lines, including 49,300 miles of rural overhead lines, 16,500 miles of urban overhead lines, 14,300 miles of rural underground lines and 12,500 miles of urban underground lines. As of December 31, 2003, the electric transmission and distribution systems had approximately 1,600 substations.

Substantially all of Franchised Electric s electric plant in service is mortgaged under the indenture relating to Duke Energy s various series of First and Refunding Mortgage Bonds.

(For a map showing Franchised Electric s properties, see Business Franchised Electric earlier in this section.)

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NATURAL GAS TRANSMISSION

Texas Eastern s gas transmission system extends approximately 1,700 miles from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York. It consists of two parallel systems, one with three large-diameter parallel pipelines and the other with one to three large-diameter pipelines. Texas Eastern s onshore system consists of approximately 8,600 miles of pipeline and 73 compressor stations.

Texas Eastern also owns and operates two offshore Louisiana pipeline systems, which extend approximately 100 miles into the Gulf of Mexico and include approximately 500 miles of Texas Eastern s pipeline system.

Algonquin Gas Transmission Company s (Algonquin) transmission system connects with Texas Eastern s facilities in New Jersey, and extends approximately 250 miles through New Jersey, New York, Connecticut, Rhode Island and Massachusetts. The system consists of approximately 1,100 miles of pipeline with six compressor stations. Algonquin is a wholly owned subsidiary of Duke Energy.

ETNG s transmission system crosses Texas Eastern s system at two points in Tennessee and consists of two mainline systems totaling approximately 1,400 miles of pipeline in Tennessee, Georgia, North Carolina and Virginia, with 18 compressor stations.

Maritimes and Northeast Pipeline s transmission system (approximately 75% owned by Duke Energy) extends approximately 900 miles from producing fields in Nova Scotia through New Brunswick, Maine, New Hampshire and Massachusetts, connecting to Algonquin in Beverly, Massachusetts. It has two compressor stations on the system.

The British Columbia Pipeline System consists of two divisions. The field services division operates more than 1,840 miles of gathering pipelines in British Columbia, Alberta, the Yukon Territory and the Northwest Territories, as well as 22 field compressor stations; four gas processing plants located in British Columbia near Fort Nelson, Taylor, Chetwynd and in the Sikanni area northwest of Fort St. John, and three elemental sulphur recovery plants located at Fort Nelson, Taylor and Chetwynd. Total contractible capacity of approximately 1.8 Bcf of residue gas per day. The pipeline division has approximately 1,740 miles of transmission pipelines in British Columbia and Alberta, as well as 18 mainline compressor stations.

Union Gas owns and operates natural gas transmission, distribution and storage facilities in Ontario. Union Gas distributes natural gas to customers in northern, southwestern and eastern Ontario and provides storage, transportation and related services to utilities and other industry participants in the gas markets of Ontario, Quebec and the Central and Eastern U.S. Union Gas underground natural gas storage facilities have a working capacity of approximately 150 Bcf in 20 underground facilities located in depleted gas fields. Its transmission system consists of approximately 3,000 miles of pipeline and six mainline compressor stations. Union Gas distribution system consists of approximately 21,000 miles of distribution.

MHP owns and operates two natural gas storage facilities: Moss Bluff and Egan. The Moss Bluff facility consists of three storage caverns located in Liberty and Chambers counties near Houston, Texas and has access to five pipelines. The Egan facility consists of three storage caverns located in Acadia Parish in the south central part of Louisiana and has access to seven pipeline facilities.

(For a map showing natural gas transmission and storage properties and additional information on Natural Gas Transmission s properties, see Business Natural Gas Transmission earlier in this section.)

FIELD SERVICES

(For information and a map showing Field Services properties, see Business Field Services earlier in this section.)

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DUKE ENERGY NORTH AMERICA

The following table provides information about DENA s generation portfolio in operation as of December 31, 2003.

Name	Gross MW	Net MW	Plant Type	Primary Fuel	Location	Approximate Ownership Interest (percentage)
Moss Landing	2,538	2,538	Combined Cycle	Natural Gas	CA	100%
Hanging Rock	1,240	1,240	Combined Cycle	Natural Gas	OH	100
Murray(a)	1,240	1,240	Combined Cycle	Natural Gas	GA	100
Morro Bay	1,002	1,002	Combined Cycle	Natural Gas	CA	100
South Bay	700	700	Combined Cycle	Natural Gas	CA	100
Enterprise Energy(a)	640	640	Simple Cycle	Natural Gas	MS	100
Lee	640	640	Simple Cycle	Natural Gas	IL	100
Marshall(a)	640	640	Simple Cycle	Natural Gas	KY	100
Sandersville(a)	640	640	Simple Cycle	Natural Gas	GA	100
Southhaven(a)	640	640	Simple Cycle	Natural Gas	MS	100
Vermillion	640	640	Simple Cycle	Natural Gas	IN	100
Fayette	620	620	Combined Cycle	Natural Gas	PA	100
Hot Springs(a)	620	620	Combined Cycle	Natural Gas	AR	100
Washington	620	620	Combined Cycle	Natural Gas	OH	100
Griffith Energy	600	300	Combined Cycle	Natural Gas	AZ	50
Arlington Valley	570	570	Combined Cycle	Natural Gas	AZ	100
Hinds(a)	520	520	Combined Cycle	Natural Gas	MS	100
Maine Independence	520	520	Combined Cycle	Natural Gas	ME	100
St. Francis	500	250	Combined Cycle	Natural Gas	MO	50
Bridgeport	490	326	Combined Cycle	Natural Gas	CT	67
New AlbanyEnergy(a)	385	385	Simple Cycle	Natural Gas	MS	100
Bayside	260	195	Combined Cycle	Natural Gas	NB	75
Oakland	165	165	Simple Cycle	Oil	CA	100
McMahon	117	59	Cogen	Natural Gas	BC	50
Ft. Francis	110	110	Cogen	Natural Gas	ON	100
Total	16,657	15,820				

(a) Southeast region

(For a map showing DENA s properties, see Business Duke Energy North America earlier in this section.)

INTERNATIONAL ENERGY

The following table provides information about International Energy s generation portfolio in operation as of December 31, 2003

Name	Gross MW	Net MW	Fuel	Location	Approximate Ownership Interest (percentage)
Paranapanema	2,307	2,185	Hydro	Brazil	95%
Hidroelectrica Cerros Colorados	576	523	Hydro/Natural gas	Argentina	91
Egenor	540	538	Hydro/Diesel/Oil	Peru	100
Acajutla	324	293	Oil/Diesel	El Salvador	90
Electroquil	180	130	Diesel	Ecuador	72
DEI Guatemala y Cia	328	328	Oil/Diesel	Guatemala	100
Aquaytia	160	61	Natural Gas	Peru	38
Empressa Electrica Corani	126	63	Hydro	Bolivia	50
Total(a)	4,541	4,121			

(a) Excludes discontinued operations

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(For additional information and a map showing International Energy s properties, see Business International Energy earlier in this section.)

CRESCENT

(For information regarding Crescent s properties, see Business Crescent earlier in this section.)

OTHER

(For information regarding the properties of the business unit now known as Other, see Business Other earlier in this section.)

Item 3. Legal Proceedings.

For information regarding legal proceedings, including regulatory and environmental matters, see Note 4 to the Consolidated Financial Statements, Regulatory Matters and Note 17 to the Consolidated Financial Statements, Commitments and Contingencies Litigation and Commitments and Contingencies Environmental.

Item 4. Submission of Matters to a Vote of Security Holders.

No matters were submitted to a vote of Duke Energy s security holders during the fourth quarter of 2003.

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PART II.

Item 5. Market for Registrant s Common Equity and Related Stockholder Matters.

Duke Energy s common stock is listed for trading on the New York Stock Exchange. As of February 27, 2004, there were approximately 147,900 common stockholders of record.

Common Stock Data by Quarter

	2003			2002		
	Dividends Per Share	Stock Price Range(a) High	Stock Price Range(a) Low	Dividends Per Share	Stock Price Range(a) High	Stock Price Range(a) Low
First Quarter	$ 0.275	$ 21.57	$ 12.21	$ 0.275	$ 40.00	$ 31.99
Second Quarter	0.550	20.75	13.51	0.550	39.60	28.50
Third Quarter		19.70	16.75		31.10	17.81
Fourth Quarter	0.275	20.89	17.08	0.275	22.00	16.42

(a) Stock prices represent the intra-day high and low stock price.

On December 17, 1998, Duke Energy s Board of Directors adopted a shareholder rights plan. Under the terms of the plan, one preference stock purchase right was distributed for each share of common stock outstanding on February 12, 1999, and for each share issued thereafter, subject to adjustment as specified. The NCUC and the PSCSC approved this distribution. The plan is intended to ensure the fair treatment of all shareholders in the event of a hostile takeover attempt and to encourage a potential acquirer to negotiate with the Board of Directors a fair price for all shareholders before attempting a takeover. The adoption of the plan was not in response to any takeover offer or threat. The Corporate Governance Committee of the Board of Directors evaluates the plan at least every three years.

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Item 6. Selected Financial Data.(d)

	2003(b)(d)	2002(d)	2001(d)	2000(d)	1999(d)
	(in millions, except per share amounts)				
Statement of Operations					
Operating revenues	$ 22,154	$ 15,898	$ 17,946	$ 15,970	$ 9,618
Operating expenses	22,872	13,295	14,367	12,934	8,163
Gains on sales of investments in commercial and multi-family properties	84	106	106	75	116
(Losses) gains on sales of other assets, net	(199)	32	238	214	132
Operating (loss) income	(833)	2,741	3,923	3,325	1,703
Other income and expenses, net	556	379	311	707	314
Interest expense	1,380	1,097	760	887	583
Minority interest expense	61	116	326	305	141
(Loss) earnings from continuing operations before income taxes	(1,718)	1,907	3,148	2,840	1,293
Income tax (benefit) expense from continuing operations	(709)	611	1,149	1,035	456
(Loss) income from continuing operations	(1,009)	1,296	1,999	1,805	837
(Loss) income from discontinued operations, net of tax	(152)	(262)	(5)	(29)	10
(Loss) income before extraordinary item and cumulative effect of change in accounting principle	(1,161)	1,034	1,994	1,776	847
Extraordinary gain, net of tax					660
Cumulative effect of change in accounting principle, net of tax and minority interest	(162)		(96)		
Net (loss) income	(1,323)	1,034	1,898	1,776	1,507
Dividends and premiums on redemption of preferred and preference stock	15	13	14	19	20
(Loss) earnings available for common stockholders	$ (1,338)	$ 1,021	$ 1,884	$ 1,757	$ 1,487
Ratio of Earnings to Fixed Charges	(c)	2.2	3.9	3.7	2.8
Common Stock Data(a)					
Shares of common stock outstanding					
Year-end	911	895	777	739	733
Weighted average	903	836	767	736	729
(Loss) earnings per share (from continuing operations)					
Basic	$ (1.13)	$ 1.53	$ 2.59	$ 2.43	$ 1.12
Diluted	(1.13)	1.53	2.57	2.42	1.12
(Loss) earnings per share (from discontinued operations)					
Basic	$ (0.17)	$ (0.31)	$ (0.01)	$ (0.04)	$ 0.01
Diluted	(0.17)	(0.31)	(0.01)	(0.04)	0.01
(Loss) earnings per share (before extraordinary item and cumulative effect of change in accounting principle)					
Basic	$ (1.30)	$ 1.22	$ 2.58	$ 2.39	$ 1.13
Diluted	(1.30)	1.22	2.56	2.38	1.13
(Loss) earnings per share					
Basic	$ (1.48)	$ 1.22	$ 2.45	$ 2.39	$ 2.04
Diluted	(1.48)	1.22	2.44	2.38	2.03
Dividends per share	1.10	1.10	1.10	1.10	1.10
Balance Sheet					
Total assets	$ 56,203	$ 60,122	$ 49,624	$ 59,276	$ 34,388
Long-term debt, less current maturities	20,622	20,221	12,321	10,717	8,683

(a) Amounts prior to 2001 were restated to reflect the two-for-one common stock split effective January 26, 2001.

(b) As of January 1, 2003, Duke Energy adopted the remaining provisions of Emerging Issues Task Force Issue No. 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and for Contracts Involved in Energy Trading and Risk Management Activities and Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. In accordance with the transition guidance for these standards, Duke Energy recorded a net-of-tax and minority interest cumulative effect adjustment for change in accounting principles. See Note 1 to the Consolidated Financial Statements, Summary of Significant Accounting Policies, for further discussion.

(c) Earnings were inadequate to cover fixed charges by $1,715 million for the year ended December 31, 2003.

(d) Certain amounts have been revised. See Note 24 to the Consolidated Financial Statements.

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Item 7. Management s Discussion and Analysis of Results of Operations and Financial Condition.

INTRODUCTION

Management s Discussion and Analysis includes the effects of revisions in order to (1) present Duke Energy s real estate operations, Crescent Resources, LLC (Crescent), as a separate reportable segment (see Note 3 to the Consolidated Financial Statements), (2) to present the effects of additional discontinued operations as a result of the change within the Field Services reportable segment (see Note 11 to the Consolidated Financial Statements), (3) to revise certain financial statement captions related to Crescent (see Note 24 to the Consolidated Financial Statements), (4) to provide updates to significant litigation matters since the original filing date of March 15, 2004 (see Note 17 to the Consolidated Financial Statements), (5) to remove the presentation of consolidated earnings before interest and taxes (EBIT) pursuant to the Securities and Exchange Commission s rules on presentation of non-GAAP financial measures, and (6) to update for material subsequent events occurring since the original filing date of March 15, 2004 (see Note 23 to the Consolidated Financial Statements). These revisions did not affect consolidated net income, total assets, liabilities or stockholders equity.

Management s Discussion and Analysis should be read in connection with the Consolidated Financial Statements.

Overview of Business Strategy and Economic Factors. Duke Energy s business strategy is to develop integrated energy businesses in targeted regions where Duke Energy s capabilities in developing energy assets; operating power plants, natural gas liquid (NGL) plants and natural gas pipelines; optimizing commercial operations (including its affiliated real estate operation); and managing risk can provide comprehensive energy solutions for customers and create value for shareholders.

The energy industry and Duke Energy are experiencing a number of challenges, including the substantial imbalance between supply and demand for electricity, the pace of economic recovery, and regulatory and legal uncertainties. In response to these current challenges, Duke Energy is focusing on reducing risks and restructuring its business to be well positioned as the energy marketplace regains its health and vigor. In 2003, Duke Energy established a platform for future growth by selling certain non-strategic assets, cutting expenses and paying down debt, while still funding capital expenditures at the core regulated Franchised Electric and Natural Gas Transmission businesses. Duke Energy also resolved many outstanding legal and regulatory issues; reduced the scope of its international operations by announcing its intention to exit the Australian and European markets; and repositioned Duke Energy North America (DENA) to be a more focused, asset-backed merchant business. The repositioning of DENA included discontinuing proprietary trading and announcing its intentions to exit the merchant generation business in the Southeast region.

Duke Energy s current goals for 2004 include: positive net cash generation; investing in its strongest businesses such as Franchised Electric, Natural Gas Transmission and Crescent; continuing to size its businesses to market realities; addressing merchant energy issues; strengthening relationships with customers; and further reducing regulatory and legal uncertainty. A major focus for 2004 will be to complete the execution of the plans Duke Energy announced for its merchant and international business, including the sale of its assets in the Southeastern U.S and Australia, and its exit from Europe. Duke Energy also plans to preserve its dividend payout of $1.10 per share and to continue to pay down debt in 2004 by $3.5 to $4.0 billion to further strengthen its balance sheet. (Included in the expected 2004 debt reduction amount is approximately $900 million of Australian dollar denominated debt related to International Energy s Australian operations.) Duke Energy believes it is well-positioned to generate cash in 2004 from operations, the settlement of the forward stock purchase component of the outstanding equity units, and from asset sales to meet its goals of reducing debt, paying the dividend and providing for maintenance and modest expansion.

Duke Energy s business model provides diversification between stable, less cyclical businesses like Franchised Electric and Natural Gas Transmission, and the traditionally higher-growth and more cyclical energy businesses like DENA, International Energy and Field Services. Additionally, Crescent s portfolio strategy is diversified between residential, commercial and multi-family development. Although Duke Energy expects to return to profitability in 2004, all of its businesses can be negatively affected by sustained downturns or sluggishness in the economy, including low market price of commodities, all of which are beyond Duke Energy s control, and could impair Duke Energy s ability to meet its goals for 2004.

Declines in demand for electricity as a result of economic downturns would reduce overall electricity sales and lessen Duke Energy s cash flows; especially as industrial customers reduce production and, thus, consumption of electricity. A portion of Franchised Electric s business risk is mitigated by its being subject to regulated allowable rates of return and recovery of fuel costs under fuel adjustment clauses. Natural Gas Transmission is also subject to mandated tariff rates and recovery of certain fuel costs. Lower economic output would also cause the Natural Gas Transmission and Field Services businesses to experience a decline in the volume of natural gas shipped through their pipelines, gathered and processed at their plants, or distributed by their local distribution company, resulting in lower revenue and cash flows. Natural Gas Transmission continues to experience positive renewals of its customer contracts as they expire.

If negative market conditions persist over time and estimated cash flows over the lives of Duke Energy s individual assets do not exceed the carrying value of those individual assets, asset impairments may occur in the future under existing accounting rules and diminish results of operations. Furthermore, a change in management s intent about the use of individual assets (held for use versus held for sale) or a change in fair value of assets held for sale could also result in an impairment. The largest impairments over the past two years have been related to DENA and International Energy and it is estimated that the most significant future risk of impairments also resides within these segments.

Duke Energy and its goals for 2004 can also be substantially at risk due to the regulation of its businesses. Duke Energy s businesses in North America are subject to regulations on the federal and state level. The majority of Duke Energy s Canadian natural gas assets is also subject to various degrees of federal or provincial regulation and are subject to the same risks. Regulations, applicable to the electric power industry and gas transmission and storage industry, have a significant impact on the nature of the businesses and the manner in which they operate. Changes to regulations are ongoing and Duke Energy cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on its business.

Additionally, Duke Energy s investments and projects located outside of the U.S. expose it to risks related to laws of other countries, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. Changes in these factors are difficult to predict and may impact Duke Energy s future results. Duke Energy s recent restructuring, which focuses its non-U.S. operations on only Latin America and Canada, will help mitigate this exposure.

Duke Energy also relies on access to both short-term money markets and longer-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flow from its operations. If Duke Energy is not able to access capital at competitive rates, its ability to implement its strategy could be adversely affected. Market disruptions or a downgrade of Duke Energy s credit rating may increase its cost of borrowing or adversely affect its ability to access one or more sources of liquidity.

RESULTS OF OPERATIONS

Overview of Drivers and Variances for 2003 and 2002

Year Ended December 31, 2003 as Compared to December 31, 2002. For 2003, earnings available for common stockholders were a loss of $1,338 million, or a loss of $1.48 per basic and diluted share. For 2002, earnings available for common stockholders were $1,021 million, or earnings of $1.22 per basic and diluted share. For Duke Energy, 2003 was a year of transition and one of Duke Energy s key goals was to establish a

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platform for future growth by cutting costs, selling non-strategic assets and exiting businesses that were not profitable or were not part of the core business. As a result, Duke Energy incurred significant charges in 2003 related to these activities; including wind-down costs, asset impairments and other charges related to current market conditions and strategic actions taken by management. Significant charges that contributed to the lower results in 2003 included:

- Charges of $2.8 billion related to asset impairment of DENA s Southeastern plants and its deferred Western plants, and wind-down costs associated with the Duke Energy Trading and Marketing, LLC (DETM) joint venture

- Charges of $262 million for the disqualification of certain hedges from the accrual method of accounting to mark-to-market accounting that were related to the impaired assets at DENA

- Charges and impairments of $292 million for International Energy s Australian and European businesses, which have been classified as discontinued operations

- A charge of $254 million for goodwill impairment at DENA, related primarily to the trading and marketing business

- Net losses of $199 million on other assets sold or held for sale

- Severance and related charges of $153 million associated with workforce reductions across all segments

- A charge of $51 million for the write-off of an abandoned corporate risk management information system

Partially offsetting these 2003 charges were net gains of $279 million on equity investment sales during the year, and when compared to 2002, $645 million of charges in 2002 related to severance, goodwill impairment for International Energy s European trading and marketing business, the termination of certain turbines on order, impairments of other uninstalled turbines, write-off of project and site development costs, demobilization costs related to deferred plants and a partial impairment of a merchant plant. (For additional information on goodwill impairments, other impairments and related charges, assets held for sale and discontinued operations, see Notes 9, 11 and 12 to the Consolidated Financial Statements)

Other key drivers of the 2003 lower results included:

- Increased interest expense of $283 million due primarily to decreased capitalized interest and higher average debt balances, primarily resulting from debt assumed in, and issued with respect to, the acquisition of Westcoast Energy Inc. (Westcoast)

- Charges related to changes in accounting principles of $162 million, net of tax and minority interest (see Note 1 to the Consolidated Financial Statements)

- Increased amortization expense of $115 million at Franchised Electric related to North Carolina clean air legislation (see Note 4 to the Consolidated Financial Statements)

A regulatory action by the Public Service Commission of South Carolina (PSCSC) which resulted in decreased earnings of $46 million at Franchised Electric, $16 million of which was an order to write-off regulatory assets related to debt issuance costs through interest expense (see Note 4 to the Consolidated Financial Statements)

International Energy s reserve and charges for environmental settlements with Brazil of $26 million

A settlement with the Commodity Futures Trading Commission (CFTC) of $17 million, net of minority interest expense, by DENA (see Note 17 to the Consolidated Financial Statements)

Milder weather which negatively impacted operations at DENA and Franchised Electric

Foregone earnings of assets and equity investments sold

The above decreases in earnings were partially offset by additional earnings in 2003 from the Westcoast acquisition in March 2002.

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Year Ended December 31, 2002 as Compared to December 31, 2001. In 2002, earnings available for common stockholders were $1,021 million, or $1.22 per basic and diluted share, compared to $1,884 million, or $2.45 per basic share and $2.44 per diluted share, in 2001. The decrease was due primarily to:

Decreased trading and marketing results, due primarily to negative impacts of a prolonged economic downturn, low commodity prices, low volatility levels, reduced sparks spreads and decreased market liquidity

Charges at several business units, such as asset impairments and severance costs, related to market conditions in 2002 and strategic actions taken by management

A decline in the average price realized for electricity generated by Duke Energy s merchant plants

An increase in interest expense due primarily to the debt assumed in the acquisition of Westcoast

The above drivers were partially offset by:

Increased transportation, storage and distribution income from assets acquired or consolidated as a part of the acquisition of Westcoast in March 2002

A one-time net-of-tax charge in 2001 of $96 million, or $0.13 per basic share, related to the cumulative effect of a change in accounting principle for the January 1, 2001 adoption of Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities

For additional information on specific business unit related items, see the segment discussions that follow. For a detailed discussion of interest, taxes and the change in accounting principles, see Other Impacts on Earnings Available for Common Stockholders at the end of this section.

Consolidated Operating Revenues

Year Ended December 31, 2003 as Compared to December 31, 2002. Consolidated operating revenues for 2003 increased $6,256 million, compared to 2002. This change was driven by a $5,368 million increase in Non-regulated Electric, Natural Gas, Natural Gas Liquids and Other revenues, due primarily to increased NGL pricing, and due to the adoption of the final consensus on Emerging Issues Task Force (EITF) Issue No. 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and for Contracts Involved in Energy Trading and Risk Management Activities, on January 1, 2003. As of that date, Duke Energy began to report revenues and expenses for certain derivative and non-derivative gas and other contracts on a gross basis instead of a net basis. Adopting the final consensus on EITF Issue No. 02-03 did not require a change to prior periods, which had already been changed in 2002 to report amounts on a net basis in accordance with earlier provisions of EITF Issue No. 02-03.

Regulated Natural Gas revenues also increased $742 million due primarily to increased transportation, storage and distribution revenues from assets acquired or consolidated as a part of the acquisition of Westcoast in March 2002.

Year Ended December 31, 2002 as Compared to December 31, 2001. Consolidated operating revenues for 2002 decreased $2,048 million, compared to 2001. The decrease was due primarily to decreased trading and marketing net margins (included in Non-regulated Electric, Natural Gas, Natural Gas Liquids, and Other revenues on the Consolidated Statements of Operations) as a result of the negative impacts of a prolonged economic weakness, low commodity prices, continued low volatility levels, reduced spark spreads and decreased market liquidity. The decrease was also a result of decreased revenues on the sale of natural gas, NGLs and other petroleum products. The decrease was partially offset by increased transportation, storage and distribution revenue from assets acquired or consolidated as part of the Westcoast acquisition in March 2002.

For a more detailed discussion of operating revenues, see the segment discussions that follow.

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Consolidated Operating Expenses

Year Ended December 31, 2003 as Compared to December 31, 2002. Consolidated operating expenses for 2003 increased $9,577 million, compared to 2002. Changes in consolidated operating expenses were driven primarily by asset impairments and related charges, and by the same drivers that affected consolidated operating revenues: increased purchase costs for NGLs and the adoption of the final consensus on EITF Issue No. 02-03, and additional expenses due to the acquisition of Westcoast.

Year Ended December 31, 2002 as Compared to December 31, 2001. Consolidated operating expenses for 2002 decreased $1,072 million, compared to 2001. The decrease was due primarily to a reduction in expenses related to the purchases of natural gas, NGLs and other petroleum products. The decrease was partially offset by increased operating expenses from assets acquired or consolidated as part of the Westcoast acquisition in March 2002, and various asset impairment and severance charges related to market conditions and strategic actions taken by management.

For a more detailed discussion of operating expenses, see the segment discussions that follow.

Consolidated Gains on Sales of Investments in Commercial and Multi-Family Real Estate

Consolidated gains on sales of investments in commercial and multi-family real estate were $84 million in 2003, and $106 million in 2002 and 2001. For a detailed discussion of this item see the Crescent segment discussion below.

Consolidated (Losses) Gains on Sales of Other Assets, net

Consolidated (losses) gains on sales of other assets, net was a loss of $199 million for 2003, a gain of $32 million for 2002, and a gain of $238 million for 2001. The loss for 2003 was comprised of a $208 million loss at DENA primarily related to charges on DETM contracts ($127 million) resulting from the wind-down of DETM s operations, and impairments recorded on assets held for sale, including a 25% undivided interest in the wholly-owned Duke Energy Vermillion facility ($18 million), and stored turbines and related equipment ($66 million). The gain for 2002 was primarily comprised of a $33 million gain on the sale of Duke Energy s remaining water operations. The gain for 2001 was primarily comprised of gains on sales of DENA s interests in several merchant energy facilities.

Consolidated Operating Income

Year Ended December 31, 2003 as Compared to December 31, 2002. For 2003, consolidated operating income decreased $3,574 million, compared to 2002. Lower operating income was driven by decreased operating income at DENA of $3,699 million, due primarily to asset impairments and related charges, as discussed above.

Year Ended December 31, 2002 as Compared to December 31, 2001. Consolidated operating income for 2002 decreased $1,182 million, compared to 2001. The decrease was driven by a $1,430 million decrease at DENA due to decreased trading and marketing results (as previously described), decreased average prices realized on electric generation, and certain charges taken as a result of 2002 market conditions and strategic actions by management. Also contributing to the decrease was a $314 million decrease at Field Services due to decreased commodity prices such as NGLs and natural gas. Slightly offsetting these decreases was a $488 million increase at Natural Gas Transmission due primarily to the acquisition of Westcoast in March 2002.

For a more detailed discussion of these variances, see segment discussions below.

Consolidated Other Income and Expenses

Other Income and Expenses increased $177 million for the year ended December 31, 2003 and $68 million for the year ended December 31, 2002. The increase for 2003 was driven primarily by DENA s $178 million gain on the sale of its 50% ownership interest in Duke/UAE Ref-Fuel LLC (Ref-Fuel) in June 2003 and Natural

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Gas Transmission s $90 million gain on sales of various investments in 2003, offset by foregone earnings from the sale of those investments. The increase for 2002 was driven by Natural Gas Transmission s $32 million gain on the sale of a portion of its partnership interests in Northern Border Partners L.P. in 2002.

Segment Results

Management evaluates segment performance primarily based on earnings before interest and taxes from continuing operations, after deducting minority interest expense related to those profits (EBIT). On a segment basis, EBIT excludes discontinued operations and represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits. Cash and cash equivalents are managed centrally by Duke Energy. Since the business units do not manage those items, the gains and losses on foreign currency remeasurement associated with cash balances, and third-party interest income on those balances, are generally excluded from the segments EBIT. Management considers segment EBIT to be a good indicator of each segment s operating performance from its continuing operations, as it represents the results of Duke Energy s ownership interest in operations without regard to financing methods or capital structures.

EBIT is viewed as a non-Generally Accepted Accounting Principle (GAAP) measure under the rules of the Securities and Exchange Commission (SEC). EBIT should not be considered an alternative to, or more meaningful than, net income or operating cash flow as determined in accordance with GAAP. Duke Energy s EBIT may not be comparable to a similarly titled measure of another company because other entities may not calculate EBIT in the same manner.

Business segment EBIT is summarized in the following table, and detailed discussions follow.

EBIT by Business Segment

	Years Ended December 31,		
	2003	2002	2001
		(in millions)	
Franchised Electric	$ 1,403	$ 1,595	$ 1,626
Natural Gas Transmission	1,317	1,161	607
Field Services	186	149	334
Duke Energy North America	(3,341)	169	1,487
International Energy	210	102	236
Crescent	133	158	167
Total reportable segment EBIT	(92)	3,334	4,457
Other	(272)	(368)	(539)
Total reportable segment and other EBIT	(364)	2,966	3,918
Minority interest expense and other(a)	26	38	(10)
Interest expense	(1,380)	(1,097)	(760)
Consolidated (loss) earnings from continuing operations before income taxes	$ (1,718)	$ 1,907	$ 3,148

(a) Includes interest income, foreign currency remeasurement gains and losses, and additional minority interest expense not allocated to the segment results.

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The amounts discussed below include intercompany transactions that are eliminated in the Consolidated Financial Statements.

Franchised Electric

	Years Ended December 31,		
	2003	2002	2001
	(in millions, except where noted)		
Operating revenues	$ 4,883	$ 4,888	$ 4,746
Operating expenses	3,533	3,329	3,185
Gains on sales of other assets, net	6		
Operating income	1,356	1,559	1,561
Other income, net of expenses	47	36	65
EBIT	$ 1,403	$ 1,595	$ 1,626
Sales, Gigawatt-hours (GWh)	82,828	83,783	79,685

The following table shows the changes in GWh sales and average number of customers for Franchised Electric for the past two years.

Increase (decrease) over prior year	2003	2002
Residential sales(a)	(2.3)%	5.2%
General service sales(a)	0.4%	2.4%
Industrial sales(a)	(5.7)%	(2.4)%
Wholesale sales	5.1%	35.4%
Total Franchised Electric sales(b)	(1.1)%	5.1%
Average number of customers	2.0%	2.4%

(a) Major components of Franchised Electric s retail sales.
(b) Consists of all components of Franchised Electric s sales, including retail sales, and wholesale sales to incorporated municipalities and to public and private utilities and power marketers.

Year Ended December 31, 2003 as Compared to December 31, 2002

Operating Revenues. Operating revenues for 2003 decreased $5 million, compared to 2002. The decrease was driven primarily by:

An $80 million decrease from lower GWh sales to retail customers due to mild weather, particularly during the summer months of 2003

A $30 million decrease due to a one year rate decrement ordered by the PSCSC during the third quarter of 2003 (see Note 4 to the Consolidated Financial Statements)

A $28 million decrease in sales to industrial customers, which continued to decline due to the sluggish economy in North Carolina and South Carolina

An $87 million increase from wholesale power sales, as a result of favorable market conditions. The primary driver was higher prices for natural gas, which increased both the market price and demand for wholesale power, coupled with availability of low cost generation (primarily coal-fired generation for Franchised Electric).

A $38 million increase due to continued growth in the number of residential and general service customers in Franchised Electric s service territory

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Operating Expenses. Operating expenses for 2003 increased $204 million, compared to 2002. The increase was driven primarily by:

- Increased depreciation and amortization expense of $137 million, primarily driven by amortization expense related to North Carolina s clean air legislation, which totaled $115 million (see Note 4 to the Consolidated Financial Statements)
- Increased severance expenses of $42 million due to additional workforce reductions in 2003
- Charges in 2003 of $40 million for right-of-way maintenance costs
- Insurance recoveries in 2002 of $25 million related to injuries and damages claims
- Decreased storm costs of $59 million, with $30 million incurred in 2003 compared to $89 million associated with an ice storm in December 2002
- Decreased purchased power expense of $12 million, driven by lower demand from retail customers due to the milder weather

EBIT. EBIT for 2003 decreased $192 million, compared to 2002, due primarily to unfavorable weather, the one year South Carolina rate decrement and lower sales to industrial customers, coupled with increased depreciation and amortization expense, severance expenses and right-of-way maintenance costs. These changes were partially offset by increased wholesale power sales, continued growth in the number of residential and general service customers, and lower storm and purchased power expenses.

Matters Impacting Future Franchised Electric s Results

Franchised Electric continues to increase its customer base, maintain low costs and deliver high-quality customer service in the Piedmont Carolinas. The residential and general service sectors are expected to continue to grow, but this growth will be offset by a continuing decline in the industrial sector. Franchised Electric s compounded annual EBIT growth over the next three years is expected to be 0% to 2%, coupled with strong cash flows. Changes in weather, wholesale power market prices and changes to the regulatory environment could impact future financial results for Franchised Electric. In addition, Franchised Electric s results will be affected by Duke Energy s flexibility to vary the amortization expenses associated with the North Carolina clean air legislation as noted in Operating Expenses above.

Year Ended December 31, 2002 as Compared to December 31, 2001

Operating Revenues. Operating revenues for 2002 increased $142 million, compared to 2001. The increase was driven primarily by:

- A $130 million increase from increased GWh sales to retail customers, driven by favorable weather in the latter half of 2002

A $40 million increase from continued growth in the number of residential and general service customers in Franchised Electric s service territory

A $36 million reduction in 2001 revenues resulting from a refinement in the estimates used to calculate unbilled kilowatt-hour sales

A $45 million decrease in wholesale power sales, primarily driven by lower prices in 2002

A $35 million decrease from decreased GWh sales to industrial customers as a result of a slow economy in North Carolina and South Carolina

Operating Expenses. Operating expenses for 2002 increased $144 million, compared to 2001. The increase was driven primarily by:

Expenses totaling $89 million associated with an ice storm in December 2002

Increased fuel costs of $54 million, resulting from the increase in electric sales

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A $36 million charge in 2002 for severance costs related to workforce reductions

Lower operating and maintenance expenses of $20 million at Franchised Electric s generating plants

Other Income, net of expenses. Other income, net of expenses decreased $29 million in 2002, compared to 2001, due primarily to a $19 million charge resulting from the settlement agreements reached with the North Carolina Utilities Commission (NCUC) and the PSCSC. (See Note 4 to the Consolidated Financial Statements.)

EBIT. EBIT for 2002 decreased $31 million, compared to 2001, primarily as a result of increased operating expenses, including costs associated with an ice storm in December 2002, severance costs related to workforce reductions, and charges resulting from the settlement agreements reached by Duke Energy with the NCUC and the PSCSC. The increase in operating expenses was offset by increases in revenues as discussed above.

Natural Gas Transmission

	Years Ended December 31,		
	2003	**2002**	**2001**
	(in millions, except where noted)		
Operating revenues	$ 3,197	$ 2,464	$ 1,060
Operating expenses	1,969	1,420	504
Gains on sales of other assets, net	7		
Operating income	1,235	1,044	556
Other income, net of expenses	125	148	51
Minority interest expense	43	31	
EBIT	$ 1,317	$ 1,161	$ 607
Proportional throughput, TBtu(a)	3,362	3,160	1,781

(a) Trillion British thermal units. Revenues are not significantly impacted by pipeline throughput fluctuations since revenues are primarily composed of demand charges.

Year Ended December 31, 2003 as Compared to December 31, 2002

Operating Revenues. Operating revenues for 2003 increased $733 million, compared to 2002. This increase was driven primarily by:

A $466 million increase in transportation, storage and distribution revenue in January and February 2003 from assets acquired or consolidated as a part of the Westcoast acquisition in March 2002 (see Note 2 to the Consolidated Financial Statements)

A $177 million increase due to foreign exchange favorably impacting revenues from the Canadian operations as a result of the strengthening Canadian dollar

An $81 million increase from recovery of natural gas commodity costs that are passed through to customers without a mark-up at Union Gas Limited (Union Gas). This amount is offset in expenses.

A $31 million increase from completed and operational business expansion projects in the U.S.

A $58 million decrease from operations sold in 2003 and the fourth quarter of 2002 (see Note 2 to the Consolidated Financial Statements)

Operating Expenses. Operating expenses for 2003 increased $549 million, compared to 2002. This increase was driven primarily by:

A $319 million increase in transportation, storage, and distribution expenses in January and February 2003 from assets acquired or consolidated as a part of the Westcoast acquisition in March 2002

A $132 million increase caused by foreign exchange impacts

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An $81 million increase related to increased natural gas prices at Union Gas. This amount is offset in revenues.

A $20 million increase from 2003 severance charges related to workforce reductions

A $38 million decrease from operations sold in the fourth quarter of 2002 and in 2003

For the year ended December 31, 2003, Natural Gas Transmission s operating expenses increased approximately 39% when compared to the same period in 2002, while operating revenues increased approximately 30%. The difference was due to the Westcoast operations that were acquired in March 2002. The operating expenses, as a percentage of operating revenues, of the acquired Westcoast natural gas distribution business, are greater than the previously owned natural gas transmission business. Gas commodity costs related to the Westcoast distribution business are recovered from customers by increasing revenues by the amount of gas commodity costs expensed (i.e. flowed through to customers with no incremental profit).

Other Income, net of expenses. Other income, net of expenses decreased $23 million for 2003, compared to 2002. This decrease was driven primarily by:

A $36 million decrease from negative foreign exchange impacts in 2003, due to the settlement of hedges related to foreign currency exposure

A $33 million decrease in equity earnings associated with the sold investments

A $28 million decrease due to a construction fee received in 2002 from an affiliate related to the successful completion of the Gulfstream Natural Gas System, LLC (Gulfstream), 50% owned by Duke Energy which went into service in May 2002

A $58 million increase in gains from the sale of various equity investments in 2003 (see Note 2 to the Consolidated Financial Statements)

A $17 million increase in allowance for funds used during construction related to additional capital projects

Minority Interest Expense. Minority interest expense increased $12 million for 2003, compared to 2002. This resulted from the recognition of a full year of minority interest expense in 2003, versus only ten months during 2002, from less than 100% owned subsidiaries acquired in the March 2002 acquisition of Westcoast.

EBIT. EBIT for 2003 increased $156 million, compared to 2002, due primarily to incremental EBIT related to assets acquired or consolidated as part of the March 2002 acquisition of Westcoast, gains on asset sales, and business expansion projects in the U.S. These items were partially offset by earnings in 2002 from operations that were sold in the fourth quarter of 2002 and during 2003, and 2003 severance charges in excess of 2002 amounts.

Matters Impacting Future Natural Gas Transmission s Results

Natural Gas Transmission plans to continue earnings growth through capital efficient expansions in existing markets, optimization of existing systems, and organizational efficiencies and cost control. Natural Gas Transmission expects modest annual EBIT growth over the next three years from its 2003 EBIT. The average contract life for the U.S. pipelines is nine years. Changes in the Canadian dollar, weather, throughput and the ability to renew service contracts would impact future financial results at Natural Gas Transmission.

Year Ended December 31, 2002 as Compared to December 31, 2001

Operating Revenues. Operating revenues for 2002 increased $1,404 million, compared to 2001. This increase resulted primarily from increased transportation, storage, and distribution revenue of $1,380 million from assets acquired or consolidated as a part of the Westcoast acquisition in March 2002. Revenues also increased $35 million due to business expansion projects.

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Operating Expenses. Operating expenses for 2002 increased $916 million, compared to 2001. This increase was driven primarily by:

- Incremental operating expenses of $877 million related to the gas transmission, storage and distribution assets acquired or consolidated in the Westcoast acquisition in March 2002
- Severance costs of $9 million associated with a workforce reduction in 2002
- Incremental operating expenses associated with business expansion projects
- Reversal of reserves of $25 million related to certain environmental issues that were resolved in 2002
- Reduced goodwill amortization of $14 million in 2002 as a result of the implementation of SFAS No. 142, Goodwill and Other Intangible Assets

Other Income, net of expenses. Other income, net of expenses increased $97 million in 2002, compared to 2001, partly as a result of a $28 million construction fee from an unconsolidated affiliate related to the successful completion of the Gulfstream project in 2002 and associated incremental earnings of $19 million. Also contributing to the increase in other income was a $32 million gain in 2002 on the sale of a portion of Natural Gas Transmission s limited partnership units in Northern Border Partners, L.P. and an increase in allowance for funds used during construction related to capital projects.

Minority Interest Expense. Minority interest expense for 2002 resulted from consolidating less than 100% owned subsidiaries acquired in the March 2002 acquisition of Westcoast.

EBIT. EBIT for 2002 increased $554 million, compared to 2001. As discussed above, this increase resulted primarily from incremental EBIT related to assets acquired or consolidated as part of the acquisition of Westcoast in March 2002. EBIT was also impacted by a construction fee from an unconsolidated affiliate related to the successful completion of Gulfstream, and incremental earnings from Gulfstream which went into service in May 2002. EBIT was impacted, to a lesser extent, by the reversal of reserves as a result of the resolution of certain environmental issues during 2002 and the implementation of SFAS No. 142, resulting in the elimination of goodwill amortization.

Field Services

	Years Ended December 31,		
	2003	**2002**	**2001**
	(in millions, except where noted)		
Operating revenues	$ 8,661	$ 5,990	$ 8,341
Operating expenses	8,428	5,854	7,891
Losses on sales of other assets, net	(4)		

Operating income	229	136	450
Other income, net of expenses	67	60	45
Minority interest expense	110	47	161
EBIT	$ 186	$ 149	$ 334
Natural gas gathered and processed/transported, TBtu/d (a)	7.5	8.0	8.2
NGL production, MBbl/d (b)	359.1	384.4	390.0
Average natural gas price per MMBtu (c)	$ 5.39	$ 3.22	$ 4.27
Average NGL price per gallon (d)	$ 0.53	$ 0.38	$ 0.45

(a) Trillion British thermal units per day
(b) Thousand barrels per day
(c) Million British thermal units
(d) Does not reflect results of commodity hedges

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Year Ended December 31, 2003 as Compared to December 31, 2002

Operating Revenues. Operating revenues for 2003 increased $2,671 million, compared to 2002. The increase was due primarily to a $2.17 per MMBtu increase in average natural gas prices of approximately $2,250 million and a $0.15 per gallon increase in average NGL prices of approximately $1,195 million. Lower throughput and NGL production partially offset higher revenues by approximately $120 million related to natural gas volume and approximately $380 million related to lower NGL production. The results of cash flow hedging also partially offset higher revenues by approximately $179 million, as hedge contracts locked in an average MMBtu price below market.

Operating Expenses. Operating expenses for 2003 increased $2,574 million, compared to 2002. The increase was due primarily to increased costs of raw natural gas and natural gas liquids supply of approximately $2,985 million, offset by lower throughput volumes of approximately $440 million. Other factors contributing to higher operating expenses included severance charges in 2003 and other employee related expenditure increases totaling approximately $36 million.

Offsetting increases in operating expenses were 2002 charges related to Field Services internal review of balance sheet accounts of approximately $53 million ($37 million at Duke Energy s 70% share), which may be related to corrections of accounting errors in periods prior to 2002. These adjustments were made in the following five categories: operating expense accruals; gas inventory valuations; gas imbalances; joint venture and investment account reconciliations; and other balance sheet accounts and were immaterial to Duke Energy s reported results.

Minority Interest Expense. Minority interest expense at Field Services increased $63 million in 2003, compared to 2002, due to increased earnings from Duke Energy Field Services, LLC (DEFS), Duke Energy s joint venture with ConocoPhillips. The increase in minority interest expense was not proportionate to the increase in Field Services earnings as the Field Services segment includes the results of incremental hedging activities contracted at the Duke Energy corporate level that are not included in DEFS.

EBIT. EBIT for 2003 increased $37 million compared to the same period in 2002, as a result of better pricing and other factors discussed above.

Matters Impacting Future Field Services Results

Field Services has developed significant size and scope in natural gas gathering and processing and NGL marketing and plans to focus on organic growth. Field Services estimates 8% to 10% compounded annual EBIT growth over the next three years. However, Field Services revenues and expenses are significantly dependent on prevailing commodity prices for NGLs and natural gas, and past and current trends in price changes of these commodities may not be indicative of future trends.

In 2003, DEFS converted a portion of their keep whole contracts to add a minimum fee clause to the keep whole contract and/or converted the contracts to percent of proceeds contracts. This had the impact of reducing DEFS exposure to natural gas prices and reducing the exposure to NGL prices on an unhedged basis. After considering the impacts of hedging, DEFS exposure to a one cent per gallon change in the average price of NGLs is $6 million for 2004 and $7 million for 2003.

Year Ended December 31, 2002 as Compared to December 31, 2001

Operating Revenues. Operating revenues for 2002 decreased $2,351 million, compared to 2001. The decrease was due primarily to a $1.05 per MMBtu decrease in average natural gas prices and a decrease in average NGL prices of approximately $0.07 per gallon. Other factors contributing to lower operating revenues were reduced levels of natural gas gathered and processed/transported (throughput) of 0.2 TBtu per day, and a lower trading and marketing net margin as a result of market conditions.

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Operating Expenses. Operating expenses for 2002 decreased $2,037 million, compared to 2001. The decrease was due primarily to a decrease in average natural gas prices of $1.05 per MMBtu, a $0.07 per gallon decrease in average NGL prices and lower throughput levels. Partially offsetting these decreases were increases in operating and maintenance costs and general administrative costs of $113 million, resulting from increased maintenance on equipment, pipeline integrity and core business process improvements. Additionally, Field Services recorded, as part of its internal review of balance sheet accounts, approximately $53 million of charges ($37 million at Duke Energy s 70% share) in 2002, as described above.

Minority Interest Expense. Minority interest at Field Services decreased $114 million in 2002, compared to 2001, due primarily to decreased earnings from DEFS, Duke Energy s joint venture with ConocoPhillips. The decrease in minority interest expense was not proportionate to the decrease in Field Services earnings as the Field Services segment includes the results of incremental hedging activities contracted at the Duke Energy corporate level that are not included in DEFS.

EBIT. EBIT for 2002 decreased $185 million, compared to 2001, primarily as a result of the changes in commodity prices and increases in operating, and general and administrative costs.

Duke Energy North America

	Years Ended December 31,		
	2003	**2002**	**2001**
	(in millions, except where noted)		
Operating revenues	$ 4,321	$ 1,552	$ 3,014
Operating expenses and impairments	7,767	1,507	1,768
(Losses) gains on sales of other assets, net	(208)		229