(in millions)		
2009	$ 307	
2010	309	
2011	308	
2012	123	
2013	63	
Thereafter	-	(a)
Total	$ 1,110	

(a) Obligations after 2013 are indexed to future market prices and will not be included above until prices are set using the contracted methodology.

Construction Program. LG&E had $39 million of commitments in connection with its construction program at December 31, 2008.

In June 2006, LG&E and KU entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights. The parties have commenced certain negotiations relating to potential construction cost increases due to higher labor and per diem costs above an established baseline, and certain safety and compliance costs resulting from a change in law. LG&E's share of additional costs from inception of the contract through the expected project completion in 2010 may be approximately $5 million.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the KDAQ in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendency of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, LG&E administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. In January 2008, the KDAQ issued a final permit revision. The environmental groups did not appeal the final Order upholding the permit or file a petition challenging the permit revision by the applicable deadlines. However, in October 2007, the environmental groups filed a lawsuit in federal court seeking an order for the EPA to grant or deny their pending petition for the EPA to "veto" the state air permit and in April 2008, they filed a petition seeking veto of the permit revision. In September 2008, the EPA issued an Order denying nine of eleven claims alleged in one of the petitions, but finding deficiencies in two areas of the permit. The KDAQ revised the permit to address the issues identified in the EPA's Order, although the Sierra Club subsequently submitted comments objecting to the revisions. Although the Company does not expect material changes in the permit as a result of the various petitions, the EPA has yet to rule on several additional claims. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial condition or results of operations.

Mine Safety Compliance Costs. In March 2006, the Mine Safety and Health Administration enacted Emergency Temporary Standards regulations and has issued additional regulations as the result of the passage of the Mine Improvement and New Emergency Response Act of 2006, which was signed into law in June 2006. At the state level, Kentucky and other states that supply coal to LG&E, have passed new mine safety legislation. These pieces of legislation require all underground coal mines to implement new safety measures and install new safety equipment. Under the terms of some of the coal contracts LG&E has in place, provisions are made to allow for price adjustments for compliance costs resulting from new or amended laws or regulations. LG&E has begun to receive information from the mines it contracts with regarding price adjustments related to these compliance costs and has hired a consultant to review all supplier claims for validity and reasonableness. At this time LG&E has not been notified of claims by all mines and is reviewing those claims it has received. An adjustment will be made to the value of the coal inventory once the amount is determinable, however, the amount cannot be estimated at this time. The Company expects to recover these costs through the FAC.

Environmental Matters. LG&E's operations are subject to a number of environmental laws and regulations, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to LG&E's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, LG&E's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In March 2008, the EPA issued a revised NAAQS for ozone, which contains a more stringent standard than that contained in the previous regulation. At present, LG&E is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

In July 2008, a federal appeals court issued a ruling finding deficiencies in the CAIR and vacating it. In December 2008, the Court amended its previous Order, directing the EPA to promulgate a new regulation, but leaving the CAIR in the interim. Depending upon the course of such matters, the CAIR could be superseded by new or revised NOx or SO_2 regulations with different or more stringent requirements and SIPs which incorporate CAIR requirements could be subject to revision. LG&E is also reviewing aspects of its compliance plan relating to the CAIR, including scheduled or contracted pollution control construction programs. Finally, as discussed below, the remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and LG&E's and KU's compliance plans relating thereto, due to the interconnection of the CAIR and CAIR-associated steps with such associated programs. At present, LG&E is not able to predict the outcomes of the legal and regulatory proceedings related to the CAIR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR. In addition, in 2006, the Metro Louisville Air Pollution Control District adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has announced that it intends to promulgate a new rule to replace the CAMR. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new mercury reduction rules with different or more stringent requirements. Kentucky has also repealed its corresponding state mercury regulations. At present, LG&E is not able to predict the outcomes of the legal and regulatory proceedings related to the CAMR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the remand of CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. LG&E had previously installed flue gas desulfurization equipment on all of its generating units prior to the effective date of the acid rain program. LG&E's strategy for its Phase II SO_2 requirements, which commenced in 2000, is to use accumulated emission allowances to defer additional capital expenditures and LG&E will continue to evaluate improvements to further reduce SO_2 emissions. In order to achieve the NOx emission reductions mandated by the NOx SIP Call, LG&E installed additional NOx controls, including selective catalytic reduction technology, during the 2000 through 2008 time period at a cost of $197 million. In 2001, the Kentucky Commission granted recovery in principal of these costs incurred by LG&E for these projects under its periodic environmental surcharge mechanisms. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve mandated emissions reductions, LG&E expects to incur additional capital expenditures totaling $100 million during the 2009 through 2011 time period for pollution control equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by the Company for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. LG&E believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. LG&E's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. LG&E will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level.

Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are on-going. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. LG&E is monitoring on-going efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. LG&E is also monitoring on-going regulatory proceedings including the EPA's advanced notice of proposed rulemaking for regulation of GHGs under the existing authority of the Clean Air Act and proposed rules governing carbon sequestration. The new administration has announced its intention to exercise its existing authority under the Clean Air Act to achieve reductions in GHG emissions. LG&E is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, LG&E could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of LG&E, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's Ghent 2 generating unit. LG&E and KU have complied with the information requests and are not able to predict further proceedings in this matter at this time.

General Environmental Proceedings. From time to time, LG&E appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include remediation obligations or activities for former manufactured gas plant sites or elevated PCB levels at existing properties; liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; on-going claims regarding alleged particulate emissions from LG&E's Cane Run station and claims regarding GHG emissions from LG&E's generating stations. With respect to the former manufactured gas plant sites, LG&E has estimated that it could incur additional costs of less than $1 million for remaining clean-up activities under existing approved plans or agreements. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of LG&E.

Note 10 - Jointly Owned Electric Utility Plant

LG&E owns a 75% undivided interest in Trimble County Unit 1 which the Kentucky Commission has allowed to be reflected in customer rates. Of the remaining 25% of the unit, IMEA owns a 12.12% undivided interest, and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate ownership share of fuel cost, operation and maintenance expenses and incremental assets.
The following data represent shares of the jointly owned property:

	Trimble County Unit 1			
	LG&E	IMPA	IMEA	Total
Ownership interest	75%	12.88%	12.12%	100%
Mw capacity	383	66	62	511

(in millions)	
LG&E's 75% ownership:	
Cost	$ 606
Accumulated depreciation	251
Net book value	$ 355
Construction work in progress (included in above)	$ 12

LG&E and KU have begun construction of TC2, a jointly owned unit at the Trimble County site. LG&E and KU own undivided 14.25% and 60.75% interests, respectively, in TC2. Of the remaining 25% of TC2, IMEA owns a 12.12% undivided interest and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate share of capital cost during construction, and fuel, operation and maintenance cost when TC2 begins operation, which is expected to occur in 2010. In June 2008, LG&E transferred assets related to TC2 with a net book value of $10 million to KU.

	TC2				
	LG&E	KU	IMPA	IMEA	Total
Ownership interest	14.25%	60.75%	12.88%	12.12%	100%
Mw capacity	107	455	97	91	750

(in millions)			
LG&E's 14.25% ownership:		KU's 60.75% ownership:	
Cost	$ 136	Cost	$ 560
Accumulated depreciation	2	Accumulated depreciation	-
Net book value	$ 134	Net book value	$ 560

	LG&E	KU
Construction work in progress (included in above)	$132	$550

LG&E and KU jointly own the following CTs and related equipment:

($ in millions)	LG&E				KU				Total			
Ownership Percentage	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value
LG&E 53%, KU 47% (a)	146	62	(15)	47	129	53	(12)	41	275	115	(27)	88
LG&E 38%, KU 62% (b)	118	51	(8)	43	190	82	(14)	68	308	133	(22)	111
LG&E 29%, KU 71% (c)	92	32	(6)	26	228	80	(18)	62	320	112	(24)	88
LG&E 37%, KU 63% (d)	236	79	(12)	67	404	137	(21)	116	640	216	(33)	183
LG&E 29%, KU 71% (e)	n/a	3	(1)	2	n/a	9	(2)	7	n/a	12	(3)	9

(a) Comprised of Paddy's Run 13 and E.W. Brown 5. In addition to the above jointly owned utility plant, there is an inlet air cooling system attributable to unit 5 and units 8-11 at the E.W. Brown facility. This inlet air cooling system is not jointly owned, however, it is used to increase production on the units to which it relates, resulting in an additional 10 Mw of capacity for LG&E.
(b) Comprised of units 6 and 7 at the E.W. Brown facility.
(c) Comprised of units 5 and 6 at the Trimble County facility.
(d) Comprised of CT Substation 7-10 and units 7, 8, 9 and 10 at the Trimble County facility.
(e) Comprised of CT Substation 5 and 6 and CT Pipeline at the Trimble County facility.

Both LG&E's and KU's participating share of direct expenses of the jointly owned plants is included in the corresponding operating expenses on its respective income statement (e.g., fuel, maintenance of plant, other operating expense).

Note 11 - Segments of Business and Related Information

LG&E is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity and the storage, distribution and sale of natural gas. LG&E is regulated by the Kentucky Commission and files electric and natural gas financial information separately with the Kentucky Commission. The Kentucky Commission establishes rates specifically for the electric and natural gas businesses. Therefore, management reports analyze financial performance based on the electric and natural gas segments of the business. Financial data for business segments follow:

(in millions)	Electric	Gas	Total
2008			
Operating revenues	$ 1,015	$ 452	$ 1,467
Depreciation and amortization	107	20	127
Income taxes	36	5	41
Interest income	1	-	1
Interest expense	43	10	53
Net income	82	8	90
Total assets	2,827	810	3,637
Construction expenditures	195	50	245
2007			
Operating revenues	$ 933	$ 353	$ 1,286
Depreciation and amortization	107	19	126
Income taxes	54	5	59
Interest income	1	-	1
Interest expense	41	9	50
Net income	112	8	120
Total assets	2,669	644	3,313
Construction expenditures	164	39	203

Note 12 - Related Party Transactions

LG&E, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between LG&E and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between LG&E and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

LG&E and KU purchase energy from each other in order to effectively manage the load of their retail and wholesale customers. These sales and purchases are included in the statements of income as electric operating revenues and purchased power operating expense. LG&E intercompany electric revenues and purchased power expense for the years ended December 31, were as follows:

(in millions)	2008	2007
Electric operating revenues from KU	$ 109	$ 93
Purchased power from KU	80	46

Interest Charges

See Note 8, Notes Payable and Other Short-Term Obligations, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

LG&E's intercompany interest income and expense for the years ended December 31, were as follows:

(in millions)	2008	2007
Interest on money pool loans	$ 6	$ 4
Interest on Fidelia loans	23	17

Other Intercompany Billings

E.ON U.S. Services provides LG&E with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. Services on behalf of LG&E, labor and burdens of E.ON U.S. Services employees performing services for LG&E, coal purchases and other vouchers paid by E.ON U.S. Services on behalf of LG&E. The cost of these services is directly charged to LG&E, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, LG&E and KU provide services to each other and to E.ON U.S. Services. Billings between LG&E and KU relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from LG&E to E.ON U.S. Services include cash received by E.ON U.S. Services on behalf of LG&E, primarily tax settlements, and other payments made by LG&E on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from LG&E for the years ended December 31, were as follows:

(in millions)	2008	2007
E.ON U.S. Services billings to LG&E	$ 206	$ 385
LG&E billings to KU	5	12
KU billings to LG&E	75	6
LG&E billings to E.ON U.S. Services	5	12

In June 2008, LG&E transferred assets related to TC2 with a net book value of $10 million to KU.

In March 2008, LG&E paid a dividend of $40 million to its common shareholder, E.ON U.S.

LG&E received capital contributions of $20 million from its common shareholder, E.ON U.S., in both December 2008 and December 2007.

Note 13 – Accumulated Other Comprehensive Income

Accumulated other comprehensive income (loss) consisted of the following:

(in millions)	Accumulated Derivative Gain or Loss	Pre-Tax	Income Taxes	Net
Balance at December 31, 2006	$ (15)	$ (15)	$ 6	$ (9)
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	(6)	(6)	2	(4)
Balance at December 31, 2007	$ (21)	$ (21)	$ 8	$ (13)
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	(1)	(1)	-	(1)
Balance at December 31, 2008	$ (22)	$ (22)	$ 8	$ (14)

Note 14 - Subsequent Events

On January 13, 2009, LG&E, the AG, KIUC and all other parties to the rate cases filed a settlement agreement with the Kentucky Commission. Under the terms of the settlement agreement, LG&E's base gas rates will increase $22 million annually, and base electric rates will decrease $13 million annually. An Order approving the settlement was received on February 5, 2009. The new rates were implemented effective February 6, 2009. However, in connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit, respectively, terminated, which will amount in increased revenues of approximately $21 million annually.

On January 27 and 28, 2009, a significant winter ice storm passed through LG&E's service territory causing approximately 205,000 customer outages, followed closely by a severe wind storm on February 11, 2009, causing approximately 37,000 customer outages. LG&E currently estimates costs incurred of $34 million of expenses and $6 million of capital expenditures related to the restoration following the two storms. The Company expects to seek recovery of these costs from the Kentucky Commission.

Note 15 - Notes to Statement of Cash Flows

Supplemental disclosures of cash flow information

(in millions)	2008	2007
Cash paid during the period for:		
Income Taxes	$ 34	$ 62
Interest on borrowed money	16	23
Interest to affiliated companies on borrowed money	22	15

Note 16 - Notes to Statement of Income for the Year

See page 115, line 6, column (g). Electric Utility Depreciation Expense includes $6 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 6, column (i). Gas Utility Depreciation Expense includes $2 million applicable to Common Utility Plant apportioned to Gas Operations.

See page 115, line 8, column (g). Electric Utility Amortization and Depletion of Utility Plant includes $4 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 8, column (i). Gas Utility Amortization and Depletion of Utility Plant includes $2 million applicable to Common Utility Plant apportioned to Gas Operations.

LG&E FERC Form 2 – December 31, 2006

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐ Resubmission No. ____	

Form 2 Approved
OMB No. 1902-0028
(Expires 6/30/2007)
Form 3-Q: Approved
OMB No.1902-0205
(Expires 6/30/2007)

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Louisville Gas and Electric Company	End of 2006/Q4

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
500 West Main Street
Suite 1800
Louisville KY 40202-4264
Telephone (502) 589 6100
Facsimile (502) 585 7875

Report of Independent Auditors

To the Shareholder of Louisville Gas and Electric Company:

We have audited the accompanying balance sheets of Louisville Gas and Electric Company as of December 31, 2006 and 2005 and the related statements of income, retained earnings and cash flows for the years then ended, included on pages 110 through 123.39 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

As described in Note 1, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Louisville Gas and Electric Company as of December 31, 2006 and 2005, and the results of its operations and its cash flows for the years then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

This report is intended solely for the information and use of the board of directors and management of Louisville Gas and Electric Company and for filing with the Federal Energy Regulatory Commission and should not be used for any other purpose.

PricewaterhouseCoopers LLP

March 29, 2007

BLANK

INSTRUCTIONS FOR FILING FERC FORM NOS. 2, 2-A and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form Nos. 2, 2-A, and 3-Q are designed to collect financial and operational information from natural gas companies subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are considered to be non-confidential public use forms.

II. Who Must Submit

Each natural gas company whose combined gas transported or stored for a fee exceed 50 million dekatherms in each of the previous three calendar years must submit FERC Form Nos. 2 and 3-Q.

Each natural gas company not meeting the filing threshold for FERC Form No. 2, but having total gas sales or volume transactions exceeding 200,000 dekatherms in each of the previous three calendar years must submit FERC Form Nos. 2-A and 3-Q.

Newly established entities must use projected data to determine whether they must file the FERC Form No. 3-Q, and FERC Form Nos. 2 or 2-A.

III. What and Where to Submit

(a) Submit FERC Form Nos 2, 2-A and 3-Q electronically through the forms submission software at http://www.ferc.gov/docs-filing/eforms/form-2/elec-subm-soft.asp.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Form Nos. 2, 2-A, and 3-Q filings.

(b) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. Do not include monthly and quarterly reports. Indicate by checking the appropriate box on FERC Form No. 2, Page 3, List of Schedules, if the reports to stockholders will be submitted or if no Annual Report to Stockholders is prepared. Unless eFiling the Annual Report to Stockholders, mail these reports to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit with the original submission of this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984) prepared in conformity with the current standards of reporting which will:

(i) attest to the conformity, in all material respects, of the schedules listed below with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U.S. (See 18 C.F.R. §§ 158.10-158.12 for specific qualifications).

Reference	Reference Schedules Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(c) Filers are encouraged to file their Annual Report to Stockholders, and CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders" and "CPA Certification Statement," have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form Nos. 2, 2-A and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-2/form-2.pdf , http://www.ferc.gov/docs-filing/eforms/form-2a/form-2a.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Form Nos. 2, 2-A, and 3-Q must be filed by the dates:

(a) FERC Form Nos. 2 and 2-A for each year ending December 31 must be filed by April 18th of the following year (18 C.F.R. §§ 260.1 and 260.2),

(b) FERC Form No. 3-Q – Natural gas companies that file a FERC Form 2 must file the FERC Form No. 3-Q within 60 days after the end of the reporting quarter (18 CFR § 260.300), and

(c) FERC Form No. 3-Q – Natural gas companies that file a FERC Form 2-A must file the FERC Form No. 3-Q within 70 days after the end of the reporting quarter (18 CFR § 260.300).

V. Where to Send Comments on Public Reporting Burden

The public reporting burden for the FERC Form 2 collection of information is estimated to average 1,570 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 2-A collection of information is estimated to average 115 hours per response. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare all reports in conformity with the Uniform System of Accounts (USofA) (18 CFR Part 201). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or Dth) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Footnote and further explain accounts or pages as necessary.

IX. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

X. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

XI. Report all gas volumes in Dth unless the schedule specifically requires the reporting in a different unit of measurement.

DEFINITIONS

I. Btu per cubic foot – The total heating value, expressed in Btu, produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1 cubic foot at a temperature of 60°F if saturated with water vapor and under a pressure equivalent to that of 30°F, and under standard gravitational force (980.665 cm. per sec) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of gas and when the water formed by combustion is condensed to the liquid state (called gross heating value or total heating value air.

II. Commission Authorization -- The authorization of the Federal Energy Regulatory Commission, or any Commission. Name the commission whose authorization was obtained and give date of the authorization.

III. Dekatherm – A unit of heating value equivalent to 10 therms or 1,000,000 Btu.

IV. Respondent – The person, corporation, licensee, agency, authority, or other legal entity or instrumentality on whose behalf the report is made.

FERC FORM NO. 2:
ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION	
01 Exact Legal Name of Respondent Louisville Gas and Electric Company	02 Year of Report Dec. 31, 2006
03 Previous Name and Date of Change (*If name changed during year*)	
04 Address of Principal Business Office at End of Year (*Street, City, State, Zip Code*) 220 W. Main Street, P.O. Box 32010, Louisville, Kentucky 40232	
05 Name of Contact Person Susan K. Emery	06 Title of Contact Person Mgr - Regulatory Accounting & Reporting
07 Address of Contact Person (*Street, City, State, Zip Code*) P.O. Box 32010, Louisville, Kentucky 40232	

08 Telephone of Contact Person, *Including Area Code*	09 This Report is	10 Date of Report (*Mo, Da, Yr*)
(502) 627-3997	(1) [x] An Original (2) [ ] A Resubmission	3/31/2007

ATTESTATION	
I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.	
01 Name S. Bradford Rives	02 Title Chief Financial Officer
03 Signature	04 Date Signed (*Mo, Da, Yr*) 3/31/2007

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr) 03/31/2007	Year of Report Dec. 31, 2006

LIST OF SCHEDULES (Natural Gas Company)

nter in column (d) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none," "not applicable," or "NA."

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr) 03/31/2007	Year of Report Dec. 31, 2006

LIST OF SCHEDULES (Natural Gas Company)(Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits) (Continued)			
Taxes Accrued, Prepaid and Charged During Year	262-263		
Miscellaneous Current and Accrued Liabilities	268		
Other Deferred Credits	269		
Accumulated Deferred Income Taxes--Other Property	274-275		
Accumulated Deferred Income Taxes--Other	276-277		
Other Regulatory Liabilities	278		
INCOME ACCOUNT SUPPORTING SCHEDULES			
Gas Operating Revenues	300-301		
Revenues from Transportation of Gas of Others Through Gathering Facilities	302-303		None
Revenues from Transportation of Gas of Others Through Transmission Facilities	304-305		None
Revenues from Storage Gas of Others	306-307		None
Other Gas Revenues	308		
Gas Operation and Maintenance Expenses	317-325		
Exchange and Imbalance Transactions	328		None
Gas Used in Utility Operations	331		
Transmission and Compression of Gas by Others	332		None
Other Gas Supply Expenses	334		
Miscellaneous General Expenses--Gas	335		
Depreciation, Depletion, and Amortization of Gas Plant	336-338		
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	340		
COMMON SECTION			
Regulatory Commission Expenses	350-351		None
Distribution of Salaries and Wages	354-355		
Charges for Outside Professional and Other Consultative Services	357		
GAS PLANT STATISTICAL DATA			
Compressor Stations	508-509		
Gas Storage Projects	512-513		
Transmission Lines	514		
Transmission System Peak Deliveries	518		
Auxiliary Peaking Facilities	519		
Gas Account--Natural Gas	520		
System Map	522		
Footnote Reference	551		None
Footnote Text	552		None
Stockholders' Reports	-		None

*FERC Form 1 pages substituted.
**Disclosed as a supplemental page located in front section of Form 2.

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

S.B. Rives
220 West Main Street
Louisville, KY 40202

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Kentucky - July 2, 1913

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Respondent furnishes electric and gas service in the City of Louisville and adjacent territory in Kentucky.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

LG&E is a wholly-owned subsidiary of E.ON U.S. LLC., formerly known as LG&E Energy LLC. E.ON U.S. is a wholly-owned subsidiary of E.ON, a German corporation, making LG&E a wholly-owned subsidiary of E.ON.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	– Not Applicable –			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None.

2. None.

3. None.

4. None.

5. None.

6. At December 31, 2006, the Company had obtained authorization from the SEC under PUHCA SEC File No. 70-09985 for the issuance of short-term debt up to $400 million through May 31, 2008. The Federal Power Act contained an exemption from FERC approval for securities issuances approved by the SEC under PUHCA. In connection with the repeal of PUHCA, the Company also received FERC authorization under the FPA Docket No. ES06-4-000 for up to $400 million in short-term debt through November 30, 2007. LG&E's money pool balance increased from $52 million at the end of the third quarter to $68 million at the end of the fourth quarter. See Note 7 of Notes to Financial Statements.

7. None.

8. None of a material nature.

9. See Notes 2, 9 and 16 of Notes to Financial Statements.

10. None.

11. N/A.

12. N/A.

13. Paula H. Pottinger was appointed Senior Vice President-Human Resources effective January 2, 2006. David A. Vogel announced his resignation as Vice President - Retail and Gas Storage Operations during March 2007.

14. The Company is a participant in a cash pooling arrangement, but its proprietary capital ratio is above 30%.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	3,903,922,638	3,888,206,980
3	Construction Work in Progress (107)	200-201	217,873,410	158,787,888
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		4,121,796,048	4,046,994,868
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,766,590,602	1,727,600,282
6	Net Utility Plant (Enter Total of line 4 less 5)		2,355,205,446	2,319,394,586
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,355,205,446	2,319,394,586
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		2,139,990	2,139,990
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		80,698	199,654
19	(Less) Accum. Prov. for Depr. and Amort. (122)		63,360	63,360
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		594,286	594,286
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,840,300	145
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,451,924	730,725
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		6,603,229	7,098,511
36	Special Deposits (132-134)		15,605,848	9,817,848
37	Working Fund (135)		23,780	57,566
38	Temporary Cash Investments (136)		5,458	27
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		84,338,640	142,196,479
41	Other Accounts Receivable (143)		29,508,161	7,995,280
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,649,125	1,073,383
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		19,407,514	36,535,701
45	Fuel Stock (151)	227	37,861,747	38,687,915
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	25,262,980	23,485,355
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	15,403	21,443

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	4,433,231	4,208,705
55	Gas Stored Underground - Current (164.1)		82,837,901	124,868,861
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		5,379,921	4,142,673
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		175,044	45,040
60	Rents Receivable (172)		37,487	47,450
61	Accrued Utility Revenues (173)		52,720,000	81,765,000
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		895,627	1,619,259
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		363,462,846	481,519,730
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		8,132,045	8,538,728
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	163,619,703	27,519,495
73	Prelim. Survey and Investigation Charges (Electric) (183)		69,034	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		756,750	287,179
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	36,346,566	67,015,483
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		19,623,273	20,644,905
82	Accumulated Deferred Income Taxes (190)	234	56,085,158	91,651,503
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		284,632,529	215,657,293
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,008,892,735	3,019,442,324

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Rresubmission	03/31/2007	end of 2006/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	425,170,424	425,170,424
3	Preferred Stock Issued (204)	250-251	71,519,300	71,519,300
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	0	0
7	Other Paid-In Capital (208-211)	253	40,005,699	40,005,699
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	1,924,169	1,924,168
11	Retained Earnings (215, 215.1, 216)	118-119	639,104,730	620,981,498
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	12,125	12,125
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-9,305,657	-58,169,830
16	Total Proprietary Capital (lines 2 through 15)		1,164,558,202	1,097,570,798
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	574,304,000	574,304,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	225,000,000	225,000,000
21	Other Long-Term Debt (224)	256-257	20,000,000	21,250,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		819,304,000	820,554,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		0	0
29	Accumulated Provision for Pensions and Benefits (228.3)		99,316,147	66,918,941
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		28,430,702	26,549,216
35	Total Other Noncurrent Liabilities (lines 26 through 34)		127,746,849	93,468,157
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		162,796,168	224,824,985
39	Notes Payable to Associated Companies (233)		67,824,000	141,245,000
40	Accounts Payable to Associated Companies (234)		54,907,690	55,733,961
41	Customer Deposits (235)		18,146,501	16,751,799
42	Taxes Accrued (236)	262-263	28,624,485	7,567,131
43	Interest Accrued (237)		2,324,124	2,308,002
44	Dividends Declared (238)		906,340	818,840
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,350,185	2,096,102
48	Miscellaneous Current and Accrued Liabilities (242)		7,075,407	7,040,175
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		119,895	623,771
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		344,074,795	459,009,766
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		16,806,393	9,866,190
57	Accumulated Deferred Investment Tax Credits (255)	266-267	41,070,237	42,091,899
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	51,278,035	41,634,195
60	Other Regulatory Liabilities (254)	278	55,370,571	41,893,418
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		366,773,191	390,926,953
64	Accum. Deferred Income Taxes-Other (283)		21,910,462	22,426,948
65	Total Deferred Credits (lines 56 through 64)		553,208,889	548,839,603
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,008,892,735	3,019,442,324

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

STATEMENT OF INCOME

Quarterly

1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the arter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,337,890,107	1,424,299,536		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	891,529,395	987,426,902		
5	Maintenance Expenses (402)	320-323	79,035,654	63,568,335		
6	Depreciation Expense (403)	336-337	117,779,352	118,023,048		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	202,919	129,151		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	5,867,355	6,116,307		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)		2,260,937	13,108,307		
14	Taxes Other Than Income Taxes (408.1)	262-263	21,708,691	20,094,516		
15	Income Taxes - Federal (409.1)	262-263	62,654,794	77,581,370		
16	- Other (409.1)	262-263	11,361,385	11,022,044		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	52,600,230	33,278,498		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	60,838,114	47,727,815		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,021,662	-4,084,533		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		1,004,606	867,263		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		2,058,041	700,956		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,179,672,497	1,252,153,209		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		158,217,610	172,146,327		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
942,660,529	987,395,634	395,229,578	436,903,902			2
						3
554,827,218	604,354,135	336,702,177	383,072,767			4
67,432,885	53,674,783	11,602,769	9,893,552			5
100,808,567	101,618,558	16,970,785	16,404,490			6
167,062	129,151	35,857				7
4,341,843	4,653,093	1,525,512	1,463,214			8
						9
						10
						11
						12
1,444,567	9,147,123	816,370	3,961,184			13
16,415,982	15,190,375	5,292,709	4,904,141			14
49,730,505	72,210,651	12,924,289	5,370,719			15
8,748,525	9,975,407	2,612,860	1,046,637			16
46,003,190	26,913,222	6,597,040	6,365,276			17
44,641,919	41,742,943	16,196,195	5,984,872			18
-848,553	-3,899,663	-173,109	-184,870			19
						20
						21
1,004,606	867,263					22
						23
1,277,593	700,956	780,448				24
801,813,725	833,763,339	377,858,772	418,389,870			25
140,846,804	153,632,295	17,370,806	18,514,032			26

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		158,217,610	172,146,327		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		129,304	350,490		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		211,758	335,332		
33	Revenues From Nonutility Operations (417)		1,174,684	872,194		
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)		604			
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		1,463,963	700,635		
38	Allowance for Other Funds Used During Construction (419.1)					
39	Miscellaneous Nonoperating Income (421)		-483,038	1,805,252		
40	Gain on Disposition of Property (421.1)			8,082		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		2,073,759	3,401,321		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		690,191			
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	1,570,962	657,551		
46	Life Insurance (426.2)					
47	Penalties (426.3)		486	22,050		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		912,095	430,615		
49	Other Deductions (426.5)		1,833,758	1,536,022		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,007,492	2,646,238		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	21,180	27,792		
53	Income Taxes-Federal (409.2)	262-263	-1,890,908	-355,847		
54	Income Taxes-Other (409.2)	262-263	-410,236	-82,680		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	275,754	149,631		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	207,234	16,060		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-2,211,444	-277,164		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-722,289	1,032,247		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		23,182,203	20,610,316		
63	Amort. of Debt Disc. and Expense (428)		408,648	403,051		
64	Amortization of Loss on Reaquired Debt (428.1)		1,021,632	1,024,421		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340	12,805,158	12,778,215		
68	Other Interest Expense (431)	340	3,249,084	2,005,939		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)					
70	Net Interest Charges (Total of lines 62 thru 69)		40,666,725	36,821,942		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		116,828,596	136,356,632		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)			12,277,207		
75	Net Extraordinary Items (Total of line 73 less line 74)			-12,277,207		
76	Income Taxes-Federal and Other (409.3)	262-263		-4,855,635		
77	Extraordinary Items After Taxes (line 75 less line 76)			-7,421,572		
78	Net Income (Total of line 71 and 77)		116,828,596	128,935,060		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		620,981,498	534,021,804
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		116,828,596	128,935,060
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	$25 Par Value 5% Cumulative - $1.25 per share		-1,075,364	(1,075,366)
25	Without Par Value Auction Rate Cumulative		-2,630,000	(1,900,000)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-3,705,364	(2,975,366)
30	Dividends Declared-Common Stock (Account 438)			
31	Without Par Value		-95,000,000	(39,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-95,000,000	(39,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		639,104,730	620,981,498
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		639,104,730	620,981,498
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements Also provide a reconciliation between "Cash and Cash quivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	116,828,596	128,935,060
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	117,981,910	118,152,199
5	Amortization of Plant	5,867,716	6,116,307
6			
7			
8	Deferred Income Taxes (Net)	10,896,096	-48,870,331
9	Investment Tax Credit Adjustment (Net)	-1,021,662	-4,084,534
10	Net (Increase) Decrease in Receivables	83,007,631	-100,519,919
11	Net (Increase) Decrease in Inventory	40,854,977	-65,817,920
12	Net (Increase) Decrease in Allowances Inventory	6,040	10,798
13	Net Increase (Decrease) in Payables and Accrued Expenses	-49,538,225	80,080,662
14	Net (Increase) Decrease in Other Regulatory Assets	-136,100,208	76,648,635
15	Net Increase (Decrease) in Other Regulatory Liabilities	13,477,153	2,775,295
16	(Less) Allowance for Other Funds Used During Construction		
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	85,172,417	-40,401,739
19	Change in Other Deferred Debits	30,668,917	-7,800,778
20	Change in Other Deferred Credits	9,643,840	5,223,184
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	327,745,198	150,446,919
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-146,347,665	-138,914,181
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-146,347,665	-138,914,181
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Change in Long-Term Investments	118,956	-223,242
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Change in Restricted Cash	-5,788,000	1,125,362
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-152,016,709	-138,012,061
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	-1,821	38,113,823
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		33,025,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	-1,821	71,138,823
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-40,000,000
74	Preferred Stock	-1,250,000	-1,250,000
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)	-73,421,000	
79			
80	Dividends on Preferred Stock	-3,705,364	-2,975,366
81	Dividends on Common Stock	-95,000,000	-39,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-173,378,185	-12,086,543
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	2,350,304	348,315
87			
88	Cash and Cash Equivalents at Beginning of Period	7,098,683	6,750,368
89			
90	Cash and Cash Equivalents at End of period	9,448,987	7,098,683

BLANK

Schedule Page: 120 Line No.: 18 Column: b

Other operating cash flows:

Net salvage and cost of removal	$ (6,535,857)
Depreciation charged to balance sheet accounts	1,247,291
Amortization of Debt Expenses	408,504
Amortization of Loss on Bonds	1,021,632
Net increase in Prepayments	(1,237,248)
Net decrease in Derivative Assets	723,632
Net increase in Preliminary Survey	(69,034)
Net increase in Clearing Accounts	(469,571)
Net increase in Other Comprehensive Income	48,864,173
Net increase in Customer Advances for Construction	6,940,203
Net increase in Asset Retirement Obligations	1,881,486
Net increase in Provision for Post Retirement Benefits	32,397,206
Total	$ 85,172,417

Schedule Page: 120 Line No.: 18 Column:

Other operating cash flows:

Net salvage and cost of removal	$ (6,967,849)
Depreciation charged to balance sheet accounts	(672,021)
Amortization of Debt Expenses	403,050
Amortization of Loss on Bonds	1,024,421
Net increase in Prepayments	(253,866)
Net increase in Derivative Assets	(1,619,259)
Net increase in Clearing Accounts	(287,179)
Net decrease in Other Comprehensive Income	(47,044,731)
Net decrease in Customer Advances for Construction	(818,037)
Net increase in Asset Retirement Obligations	16,282,871
Net decrease in Provision for Post Retirement Benefits	(449,139)
Total	$(40,401,739)

Schedule Page: 120 Line No.: 90 Column: b

Cash and cash equivalents is comprised of the following amounts:

Other Special Funds (Acct 128)	2,840,300
Cash (Acct 131)	6,603,229
Temporary Cash Investments (Acct 136)	5,458
Total Cash and Cash Equivalents at End of Period	9,448,987

Schedule Page: 120 Line No.: 90 Column:

Cash and cash equivalents is comprised of the following amounts:

Other Special Funds (Acct 128)	145
Cash (Acct 131)	7,098,511
Temporary Cash Investments (Acct 136)	27
Total Cash and Cash Equivalents at End of Period	7,098,683

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, roviding a subheading for each statement except where a note is applicable to more than one statement.
.. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
Company	LG&E
DOE	Department of Energy
DSM	Demand Side Management
ECR	Environmental Cost Recovery
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC. (formerly LG&E Energy LLC and LG&E Energy Corp.)
E.ON U.S. Services	E.ON U.S. Services Inc. (formerly LG&E Energy Services Inc.)
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
ESM	Earnings Sharing Mechanism
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelia	Fidelia Corporation (an E.ON affiliate)
FIN	FASB Interpretation No.
FT and FT-A	Firm Transportation
GHG	Greenhouse Gas
GSC	Gas Supply Clause
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IRC	Internal Revenue Code of 1986, as amended
IRP	Integrated Resource Plan
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
Kwh	Kilowatt hours
LG&E	Louisville Gas and Electric Company
LG&E Energy	LG&E Energy LLC (now E.ON U.S. LLC)
Mcf	Thousand Cubic Feet
MGP	Manufactured Gas Plant
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Mva	Megavolt-ampere
Mw	Megawatts

Mwh	Megawatt hours
NNS	No-Notice Service
NOx	Nitrogen Oxide
OVEC	Ohio Valley Electric Corporation
PBR	Performance-Based Ratemaking
Powergen	Powergen Limited (formerly Powergen plc)
PUHCA 1935	Public Utility Holding Company Act of 1935
PUHCA 2005	Public Utility Holding Company Act of 2005
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SO_2	Sulfur Dioxide
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
Tennessee Gas	Tennessee Gas Pipeline Company
Texas Gas	Texas Gas Transmission LLC
VDT	Value Delivery Team Process
WNA	Weather Normalization Adjustment

Louisville Gas and Electric Company
Notes to Financial Statements

Note 1 - Summary of Significant Accounting Policies

LG&E, incorporated in 1913 in Kentucky, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. LG&E supplies natural gas to approximately 324,000 customers and electricity to approximately 398,000 customers in Louisville and adjacent areas in Kentucky. LG&E's coal-fired electric generating stations, all equipped with systems to reduce SO_2 emissions, produce most of LG&E's electricity. The remainder is generated by a hydroelectric power plant and combustion turbines.

LG&E is a wholly-owned subsidiary of E.ON U.S., formerly known as LG&E Energy LLC. E.ON U.S. is a wholly-owned subsidiary of E.ON AG (E.ON), a German corporation, making LG&E a wholly-owned subsidiary of E.ON. LG&E's affiliate, KU, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2006 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows.

Presentation. The accompanying financial statements are prepared on the regulatory basis of accounting in accordance with the requirements of the FERC, which is a comprehensive basis of accounting other than generally accepted accounting principles. The significant differences between Generally Accepted Accounting Principles (GAAP) and FERC reporting are as follows:

- Restricted cash is recorded in cash on the balance sheet for FERC reporting and presented as a separate line item for GAAP statements;
- Certain costs of removal obligations are recorded in accumulated depreciation for FERC reporting and recorded in regulatory liabilities for GAAP reporting;
- Long-term and short-term bonds are recorded in total in the long-term debt section for FERC reporting and are presented separately in current liabilities for the short-term portion and in long-term debt for the long-term portion for GAAP reporting; and
- Deferred taxes are shown gross for FERC reporting in the balance sheet (a deferred asset and a deferred liability are recorded), for GAAP reporting the deferred taxes are netted together and recorded as a liability.

Regulatory Accounting. LG&E is subject to SFAS No. 71, under which costs that would otherwise be charged to expense are deferred as regulatory assets based on expected recovery from customers in future rates.

Likewise, credits that would otherwise be reflected as income are deferred as regulatory liabilities based on expected return to customers in future rates. LG&E's current or expected recovery of deferred costs and expected return of deferred credits is based on specific ratemaking decisions or precedent for each item as prescribed by the FERC or the Kentucky Commission. See Note 2, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Cash and Cash Equivalents. LG&E considers all debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Allowance for Doubtful Accounts. The allowance for doubtful accounts is based on the ratio of the amounts charged-off during the last twelve months to the retail revenues billed over the same period multiplied by the retail revenues billed over the last four months. Accounts with no payment activity are charged-off after four months, although collection efforts continue thereafter. The amounts charged to expense to accrue for estimated bad debts were $4 million, $3 million and $2 million and the net of accounts written off against the reserve were $3 million, $3 million and $5 million in 2006, 2005 and 2004, respectively.

Materials and Supplies. Fuel, natural gas stored underground and other materials and supplies inventories are accounted for using the average-cost method. Emission allowances are included in other materials and supplies at cost and are not currently traded by LG&E. At December 31, 2006 and 2005, the emission allowances inventory was less than $1 million.

Other Property and Investments. Other property and investments on the balance sheet consists of LG&E's investment in OVEC and non-utility plant. LG&E and 11 other electric utilities are participating owners of OVEC, located in Piketon, Ohio. OVEC owns and operates two power plants that burn coal to generate electricity, Kyger Creek Station in Ohio and Clifty Creek Station in Indiana. LG&E's share of OVEC's output is 5.63%, approximately 124 Mw of generation capacity.

As of December 31, 2006 and 2005, LG&E's investment in OVEC totaled less than $1 million. LG&E is not the primary beneficiary of OVEC; therefore, it is not consolidated into the financial statements of LG&E and is accounted for under the cost method of accounting. LG&E's maximum exposure to loss as a result of its involvement with OVEC is limited to the value of its investment. In the event of the inability of OVEC to fulfill its power provision requirements, LG&E anticipates substituting such power supply with either owned generation or market purchases and believes it would generally recover associated incremental costs through regulatory rate mechanisms. See Note 9, Commitments and Contingencies, for further discussion of developments regarding LG&E's ownership interest and power purchase rights.

Utility Plant. LG&E's utility plant is stated at original cost, which includes payroll-related costs such as taxes, fringe benefits and administrative and general costs. Construction work in progress has been included in the rate base for determining retail customer rates. LG&E has not recorded any allowance for funds used during construction, in accordance with Kentucky Commission regulations.

The cost of plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost, plus removal expense less salvage value, is charged to the reserve for depreciation. When complete operating units are disposed of, appropriate adjustments are made to the reserve for depreciation and gains and losses, if any, are recognized.

Depreciation and Amortization. Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided were approximately 3.2% in 2006 (3.0% electric, 2.9% gas, and 7.8% common); 3.2% in 2005 (3.0% electric, 2.4% gas and 8.0% common); and 3.1% for 2004 (2.9% electric, 2.8% gas and 7.6% common), of average depreciable plant. Of the amount provided for depreciation, at December 31, 2006, approximately 0.4% electric, 0.9% gas and 0.4% common were related to the retirement, removal and disposal costs of long lived assets. Of the amount provided for depreciation, at December 31, 2005, approximately 0.4% electric, 0.8% gas and 0.02% common were related to the retirement, removal and disposal costs of long lived assets.

Restricted Cash. A deposit in the amount of $11 million, used as collateral for an $83 million interest rate swap expiring in 2020, is classified as restricted cash on LG&E's balance sheet. An advance deposit of $5 million from the Louisville Arena Authority is also restricted for equipment purchases related to relocating transmission facilities.

Unamortized Debt Expense. Debt expense is capitalized in deferred debits and amortized over the lives of the related bond issues.

Income Taxes. Income taxes are accounted for under SFAS No. 109. In accordance with this statement, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, as measured by enacted tax rates that are expected to be in effect in the periods when the deferred tax assets and liabilities are expected to be settled or realized. Significant judgment is required in determining the provision for income taxes, and there are transactions for which the ultimate tax outcome is uncertain. To provide for these uncertainties or exposures, an allowance is maintained for tax contingencies based on management's best estimate of probable loss. Tax contingencies are analyzed periodically and adjustments are made when events occur to warrant a change. See Note 6, Income Taxes.

Deferred Income Taxes. Deferred income taxes are recognized at currently enacted tax rates for all material temporary differences between the financial reporting and income tax bases of assets and liabilities.

Investment Tax Credits. The EPAct 2005 added Section 48A to the Internal Revenue Code, which provides for an investment tax credit to promote the commercialization of advanced coal technologies that will generate electricity in an environmentally responsible manner. LG&E and KU received an investment tax credit related to TC2, for more details, see Note 6, Income Taxes.

Investment tax credits prior to 2006 resulted from provisions of the tax law that permitted a reduction of LG&E's tax liability based on credits for construction expenditures. Deferred investment tax credits are being amortized to income over the estimated lives of the related property that gave rise to the credits.

Revenue Recognition. Revenues are recorded based on service rendered to customers through month-end. LG&E accrues an estimate for unbilled revenues from each meter reading date to the end of the accounting period based on allocating the daily system net deliveries between billed volumes and unbilled volumes. The allocation is based on a daily ratio of the number of meter reading cycles remaining in the month to the total number of meter reading cycles in each month. Each day's ratio is then multiplied by each day's system net deliveries to determine an estimated billed and unbilled volume for each day of the accounting period. The unbilled revenue estimates included in accounts receivable were approximately $53 million and $82 million at December 31, 2006 and 2005, respectively.

Fuel and Gas Costs. The cost of fuel for electric generation is charged to expense as used, and the cost of natural gas supply is charged to expense as delivered to the distribution system. LG&E implemented a Kentucky Commission-approved performance-based ratemaking mechanism related to natural gas procurement activity. See Note 2, Rates and Regulatory Matters.

Management's Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent items at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accrued liabilities, including legal and environmental, are recorded when they are probable and estimable. Actual results could differ from those estimates.

Recent Accounting Pronouncements. The following are recent accounting pronouncements affecting LG&E:

FIN 48

In July 2006, the FASB issued FIN 48, which clarifies the accounting for the uncertainty of income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109. This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return.

The evaluation of a tax position in accordance with FIN 48 is a two-step process. The first step is recognition based on the determination of whether it is "more likely than not" that a tax position will be sustained upon examination. The second step is to measure a tax position that meets the "more likely than not" threshold. The tax position will be measured as the amount of potential benefit that exceeds 50% likelihood of being realized.

FIN 48 is effective for fiscal years beginning after December 15, 2006. FIN 48 was adopted effective January 1, 2007. The impact of FIN 48 on the statements of operations, financial position, and cash flows is not expected to be material.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, which is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. LG&E is now analyzing the future impacts of SFAS No. 157 on results of operations and financial condition.

SFAS No. 158

In September 2006, the FASB issued SFAS No. 158, which is effective for fiscal years ending after December 15, 2006 for employers with publicly traded equity securities, and for employers controlled by entities with publicly traded equity securities, which is applicable for LG&E. This statement requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or a liability in the balance sheet and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement also requires employers to measure the funded status of a plan as of the date of its year-end balance sheet. This statement amended SFAS No. 87, SFAS No. 88, SFAS No. 106 and SFAS No. 132.

SFAS No. 71 provides guidance to regulated utilities for deferring costs that would otherwise be charged to expense or equity by non-regulated enterprises. In applying the provisions of this statement to the requirements of SFAS No. 158, LG&E recorded a regulatory asset representing the adjustment to the pension liability in recognizing the funded status of the pension liability. This adjustment would have been represented in Accumulated Other Comprehensive Income without the application of SFAS No. 71.

LG&E has adopted SFAS No. 158 effective for fiscal year ending December 31, 2006. The incremental effects of applying SFAS No. 158 are shown in the following table:

(in millions)	Before Adoption of SFAS No. 158*	Adjustments	After Adoption of SFAS No. 158
Accrued pension and postretirement liability-noncurrent	$(102)	$(47)	$(149)
Accrued pension and postretirement liability-current	-	(2)	(2)
Pension and postretirement regulatory asset	77	49	126

* Balances before the application of SFAS No. 158 include the effects of 2006 plan experience and changes in actuarial assumptions on the additional minimum liability, coupled with the regulatory impacts of SFAS No. 71.

Note 2 - Rates and Regulatory Matters

The Kentucky Commission has regulatory jurisdiction over LG&E's retail rates and service, and over the issuance of certain of its securities. The Kentucky Commission has the ability to examine the rates LG&E charges its retail customers at any time.

Electric and Gas Rate Cases

In December 2003, LG&E filed an application with the Kentucky Commission requesting adjustments in LG&E's electric and natural gas rates. LG&E asked for general adjustments in electric and natural gas rates based on the twelve month test period ended September 30, 2003. The revenue increases requested were $64 million for electric and $19 million for natural gas. In June 2004, the Kentucky Commission issued an Order approving increases in LG&E's annual electric base rates of approximately $43 million (8%) and annual natural gas base rates of approximately $12 million (3%). The rate increases took effect on July 1, 2004.

During 2004 and 2005, the AG conducted an investigation of LG&E, as well as of the Kentucky Commission and its staff, requesting information regarding allegedly improper communications between LG&E and the Kentucky Commission, particularly during the period covered by the rate cases. Concurrently, the AG had filed pleadings with the Kentucky Commission requesting rehearing of the rate cases on computational components of the increased rates, including income taxes, cost of removal and depreciation amounts. In August 2004, the Kentucky Commission denied the AG's rehearing request on the cost of removal and depreciation issues and granted rehearing on the income tax component. The Kentucky Commission further agreed to hold in abeyance further proceedings in the rate cases, until the AG filed its investigative report regarding the allegations of improper communication.

In January 2005 and February 2005, the AG filed a motion summarizing its investigative report as containing evidence of improper communications and record-keeping errors by LG&E in its conduct of activities before the Kentucky Commission or other state governmental entities and forwarded such report to the Kentucky Commission under continued confidential treatment to allow it to consider the report, including its impact, if any, on completing its investigation and any remaining steps in the rate cases. To date, LG&E has neither seen nor requested copies of the report or its contents.

In December 2005, the Kentucky Commission issued an Order noting completion of its inquiry, including review of the AG's investigative report. The Order concluded that no improper communications occurred during the rate proceedings. Final proceedings took place during the first quarter of 2006 concerning the sole remaining open issue relating to state income tax rates used in calculating the granted rate increase. On March 31, 2006, the Kentucky Commission issued an Order resolving this issue in LG&E's favor consistent with the original rate increase order.

LG&E believes no improprieties have occurred in its communications with the Kentucky Commission and has cooperated with the proceedings before the AG and the Kentucky Commission. LG&E is currently unable to predict whether there will be any remaining actions or consequences as a result of the AG's report or investigation.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in LG&E's Balance Sheets as of December 31:

(in millions)	2006	2005
ARO	$ 22	$ 20
Gas supply adjustments	21	25
Unamortized loss on bonds	20	21
MISO exit	13	-
ECR	9	2
Merger surcredit	2	3
VDT costs	-	8
Other	6	5
Subtotal	93	84
Pension and postretirement benefits	126	-
Total regulatory assets	$219	$ 84
Accumulated cost of removal of utility plant	$232	$219
Deferred income taxes - net	54	42
Gas supply adjustments	31	18
Other	4	2
Total regulatory liabilities	$321	$281

LG&E does not currently earn a rate of return on the gas supply adjustments, FAC (included in other regulatory assets) and gas performance-based ratemaking regulatory assets, all of which are separate recovery mechanisms with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset which represents the changes in funded status of the plans that the Company will seek recovery of in future proceedings with the Kentucky Commission. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. LG&E expects to seek recovery of this asset in future proceedings with the Kentucky Commission. LG&E currently earns a rate of return on the remaining regulatory assets. Other regulatory liabilities include DSM and MISO Schedule 10. See Note 1, Summary of Significant Accounting Policies.

Pension and Postretirement Benefits. LG&E adopted SFAS No. 158 in 2006. This statement requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability in the balance sheet and to recognize through comprehensive income the changes in the funded status in the year in which the changes occur. Under SFAS No. 71, LG&E can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky is based on SFAS No. 87 and SFAS No. 106, both of which were amended by SFAS No. 158. Regulators have been clear and consistent with their historical treatment of such rate recovery; therefore, LG&E has recorded a regulatory asset representing the probable recovery of the portion of the change in funded status of the postretirement and pension plans that is expected to be recovered. The regulatory asset will be adjusted annually as prior service cost and actuarial losses are recognized in net periodic benefit cost.

ARO. A summary of LG&E's net ARO assets, regulatory assets, liabilities and cost of removal established under FIN 47 and SFAS No. 143, *Accounting for Asset Retirement Obligations* follows:

(in millions)	ARO Net Assets	ARO Liabilities	Regulatory Assets	Accumulated Cost of Removal
As of December 31, 2004	$ 3	$ (11)	$ 7	$ -
FIN 47 net asset additions	1	(15)	12	3
ARO accretion	-	(1)	1	-
As of December 31, 2005	4	(27)	20	3
ARO accretion	-	(1)	2	-
As of December 31, 2006	$ 4	$ (28)	$ 22	$ 3

ARO depreciation, removal cost incurred and cost of removal depreciation during 2005 and 2006 and FIN 47 net asset additions for 2006 were less than $1 million. In addition, regulatory liabilities and cost of removal depreciation as of December 31, 2005 and 2006 were less than $1 million.

Pursuant to regulatory treatment prescribed under SFAS No. 71, an offsetting regulatory credit was recorded in depreciation and amortization in the income statement of $2 million in 2006 and $1 million in 2005 for the ARO accretion and depreciation expense. LG&E AROs are primarily related to the final retirement of assets associated with generating units and natural gas wells. For assets associated with AROs, the removal cost accrued through depreciation under regulatory accounting is established as a regulatory asset or liability pursuant to regulatory treatment prescribed under SFAS No. 71. For the years ended December 31, 2006 and 2005, LG&E recorded less than $1 million of depreciation expense related to the cost of removal of ARO related assets. An offsetting regulatory liability was established pursuant to regulatory treatment prescribed under SFAS No. 71.

LG&E transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under SFAS No. 143, no material asset retirement obligations are recorded for transmission and distribution assets.

Gas Supply Cost Adjustments. LG&E's natural gas rates contain a GSC, whereby increases or decreases in the cost of natural gas supply are reflected in LG&E's rates, subject to approval by the Kentucky Commission. The GSC procedure prescribed by Order of the Kentucky Commission provides for quarterly rate adjustments to reflect the expected cost of natural gas supply in that quarter. In addition, the GSC contains a mechanism whereby any over- or under-recoveries of natural gas supply cost from prior quarters is to be refunded to or recovered from customers through the adjustment factor determined for subsequent quarters. In late 2005, as wholesale natural gas prices began to decrease, a one-time interim adjustment in the GSC was requested by LG&E and approved by the Kentucky Commission to pass the lower natural gas costs to the customers on a more timely basis.

LG&E's GSC was modified in 1997 to incorporate an experimental natural gas procurement incentive mechanism. Since November 1, 1997, LG&E has operated under this experimental PBR mechanism related to its natural gas procurement activities. LG&E's rates are adjusted annually to recover (or refund) its portion of the expense (or savings) incurred during each PBR year (12 months ending October 31). During the PBR year ending in 2006, LG&E achieved $17 million in savings. Of that total savings amount, LG&E's portion was approximately $5 million and the ratepayers' portion was approximately $12 million. Pursuant to the extension of LG&E's natural gas supply cost PBR mechanism effective November 1, 2001, the sharing mechanism under the PBR requires savings (and expenses) to be shared 25% with shareholders and 75% with ratepayers up to 4.5% of the benchmarked natural gas costs. Savings (and expenses) in excess of 4.5% of the benchmarked natural gas costs are shared 50% with shareholders and 50% with ratepayers. The current natural gas supply cost PBR mechanism was extended through 2010 without further modification.

Unamortized Loss on Bonds. The costs of early extinguishment of debt, including call premiums, legal and other expenses, and any unamortized balance of debt expense are amortized over the life of either replacement debt (in the case of refinancing) or the original life of the extinguished debt.

MISO Exit. Following receipt of applicable FERC, Kentucky Commission and other regulatory orders, LG&E withdrew from the MISO effective September 1, 2006. Specific proceedings regarding the costs and benefits of the MISO and exit matters had been underway since July 2003. Since the exit from the MISO, LG&E has been operating under a FERC-approved open access-transmission tariff. LG&E has further contracted with the Tennessee Valley Authority to act as its reliability coordinator and Southwest Power Pool, Inc. to function as its independent transmission operator, pursuant to FERC requirements, with respect to transmission matters.

LG&E and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, LG&E paid approximately $13 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. In December 2006, LG&E provided notice to the MISO of its disagreement with the calculation of the exit fee. LG&E and the MISO continue to discuss the specifics of the exit fee calculation. The outcome of these discussions and the eventual settlement of the disputed amount cannot be estimated at this time. Orders of the Kentucky Commission approving the Company's exit from the MISO have authorized the establishment of a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO Schedule 10 charges, which may continue to be collected via base rates. The treatment of the regulatory asset and liability will be determined in LG&E's next rate case; however, the Company historically has received approval to recover and refund regulatory assets and liabilities.

ECR. Kentucky law permits LG&E to recover the costs of complying with the Federal Clean Air Act, including a return of operating expenses, and a return of and on capital invested, through the ECR mechanism. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism once approved by the Kentucky Commission.

In April 2006, the Kentucky Commission initiated six-month and two-year reviews of LG&E's environmental surcharge. A final order was received in January 2007, approving the changes and credits billed through the

ECR during the review period as well as approving billing adjustments, a roll-in to base rates, revisions to the monthly surcharge filing and a rate of return on capital.

In June 2004, the Kentucky Commission issued an Order approving a settlement agreement that, among other things, revised the rate of return for LG&E's post-1995 plan. The Order also approved the elimination of LG&E's 1995 plan from its ECR billing mechanism, with all remaining costs associated with that plan to be included in their entirety in base rates.

In December 2004, LG&E filed an application with the Kentucky Commission to amend its compliance plan to allow recovery of costs associated with new and additional environmental compliance facilities, including the expansion of the landfill facility at the Mill Creek station. The estimated capital cost of the additional facilities over the next three years is approximately $25 million. A final Order was issued in June 2005, granting approval of the amendments to LG&E's compliance plan.

In June 2006, LG&E filed an application to amend its ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades at the Company's generating facilities. The estimated capital cost of the upgrades for the years 2007 through 2009 is approximately $50 million, of which $40 million is for the Air Quality Control System at TC2. A final Order was issued by the Kentucky Commission in December 2006 approving all expenditures and investments as submitted.

Merger Surcredit. As part of the LG&E Energy merger with KU Energy Corporation in 1998, LG&E estimated non-fuel savings over a ten-year period following the merger. Costs to achieve these savings were deferred and amortized over a five-year period pursuant to regulatory orders. In approving the merger, the Kentucky Commission adopted LG&E's proposal to reduce its retail customers' bills based on one-half of the estimated merger-related savings, net of deferred and amortized amounts, over a five-year period. The surcredit mechanism provides that 50% of the net non-fuel cost savings estimated to be achieved from the merger be provided to ratepayers through a monthly bill credit, and 50% be retained by LG&E and KU, over a five-year period. The surcredit was allocated 47% to LG&E and 53% to KU. In that same order, the Kentucky Commission required LG&E and KU, after the end of the five-year period, to present a plan for sharing with ratepayers the then-projected non-fuel savings associated with the merger. The Companies submitted this filing in January 2003, proposing to continue to share with ratepayers, on a 50%/50% basis, the estimated fifth-year gross level of non-fuel savings associated with the merger. In October 2003, the Kentucky Commission issued an Order approving a settlement agreement reached with the parties in the case. LG&E's merger surcredit will remain in place for another five-year term beginning July 1, 2003 and the merger savings will continue to be shared 50% with ratepayers and 50% with shareholders.

VDT. In December 2001, the Kentucky Commission issued an Order approving a settlement agreement allowing LG&E to set up a regulatory asset of $141 million for workforce reduction costs and begin amortizing it over a five-year period starting in April 2001. Some employees rescinded their participation in the voluntary enhanced severance program, which thereby decreased the charge to the regulatory asset from $144 million to $141 million. The Order reduced revenues by approximately $26 million through a surcredit on bills to ratepayers over the same five-year period, reflecting a sharing (40% to the ratepayers and 60% to LG&E) of savings as stipulated by LG&E, net of amortization costs of the workforce reduction. The five-year VDT amortization period expired in March 2006.

As part of the settlement agreements in the electric and natural gas rate cases, in September 2005, LG&E filed with the Kentucky Commission a plan for the future ratemaking treatment of the VDT surcredit and costs. In February 2006, the AG, KIUC and LG&E reached a settlement agreement on the future ratemaking treatment of the VDT surcredits and costs and subsequently submitted a joint motion to the Kentucky Commission to approve the unanimous settlement agreement. Under the terms of the settlement agreement, the VDT surcredit will continue at the current level until such time as LG&E files for a change in electric or natural gas base rates. The Kentucky Commission issued an Order in March 2006, approving the settlement agreement.

FAC. LG&E's retail electric rates contain an FAC, whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The FAC allows the Company to adjust customers' accounts for the difference between the fuel cost component of base rates and the actual fuel cost, including transportation costs. Refunds to customers occur if the actual costs are below the embedded cost component. Additional charges to customers occur if the actual costs exceed the embedded cost component. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

In January 2003, the Kentucky Commission reviewed KU's FAC and, as part of the Order in that case, required that an independent audit be conducted to examine operational and management aspects of both LG&E's and KU's fuel procurement functions. The final report was issued in February 2004. The report's recommendations related to documentation and process improvements. Management Audit Action Plans were agreed upon by LG&E and the Kentucky Commission Staff in the second quarter of 2004. LG&E filed its first Audit Progress Report with the Kentucky Commission Staff in November 2004. The second Audit Progress Report was filed May 2005. The third Audit Progress Report was filed in December 2005. In January 2006, the Kentucky Commission staff informed LG&E and KU that reporting on all of the original recommendations, but one, has been concluded. LG&E filed another Audit Progress Report on the remaining open recommendation in August 2006.

The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. In July 2006, the Kentucky Commission initiated a six-month review of the FAC for LG&E for the period of November 1, 2005 through April 30, 2006. The Kentucky Commission issued an Order in November 2006 approving the charges and credits billed through the FAC during the review period.

In December 2006, the Kentucky Commission initiated a two-year review of LG&E's past operations of the fuel clause and transfer of fuel costs from the FAC to base rates. LG&E anticipates Kentucky Commission approval of the charges and credits billed and the fuel procurement practices of LG&E during the second quarter of 2007.

DSM. LG&E's rates contain a DSM provision. The provision includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. The provision allows LG&E to recover revenues from lost sales associated with the DSM programs based on program plan engineering estimates and post-implementation evaluations.

Accumulated Cost of Removal of Utility Plant. As of December 31, 2006 and 2005, LG&E has segregated the cost of removal, embedded in accumulated depreciation, of $232 million and $219 million, respectively, in accordance with FERC Order No. 631. This cost of removal component is for assets that do not have a legal ARO under SFAS No. 143. For reporting purposes in the balance sheets, LG&E has presented this cost of removal as a regulatory liability pursuant to SFAS No. 71.

Deferred Income Taxes – Net. Deferred income taxes represent the future income tax effects of recognizing the regulatory assets and liabilities in the income statement. Deferred income taxes are recognized at currently enacted tax rates for all material temporary differences between the financial reporting and income tax bases of assets and liabilities.

Other Regulatory Matters

Regional Reliability Council. LG&E has changed its regional reliability council membership from the Reliability First Corporation to the Southeastern Electric Reliability Council, effective January 1, 2007. Regional reliability councils are industry consortiums that promote, coordinate and ensure the reliability of the bulk electric supply systems in North America.

Arena. In August 2006, LG&E filed an application with the Kentucky Commission requesting approval for sale of the Waterside property to the Louisville Arena Authority. The Kentucky Commission issued an Order in September 2006, approving the proposed transaction. In November 2006, LG&E completed certain agreements pursuant to its August 2006 Memorandum of Understanding with the Louisville Arena Authority regarding the proposed construction of an arena in downtown Louisville. LG&E entered into a relocation agreement with the Louisville Arena Authority providing for the reimbursement to LG&E of the costs to be incurred in moving certain LG&E facilities related to the arena transaction. Those costs are currently estimated to be approximately $63 million. The parties further entered into a property sale contract providing for LG&E's sale of a downtown site to the Louisville Arena Authority for approximately $10 million, which represents the appraised value of the parcel, less certain agreed upon demolition costs. The amounts specified in the contracts are subject to certain adjustments. Depending upon continuing progress of the proposed arena, the transactions contemplated by the contracts will occur between 2006 and 2010.

TC2 CCN Application. A CCN application for TC2 construction was filed with the Kentucky Commission in December 2004, and initial CCN applications for three transmission lines were filed in early 2005, with further applications submitted in December 2005. The proposed air permit was filed with the Kentucky Division for Air Quality in December 2004. In November 2005, the Kentucky Commission approved the application to expand the Trimble County generating station. Kentucky Commission approval for one transmission line CCN was granted in September 2005, and a ruling that a second transmission line was not subject to the CCN process was received in February 2006. The Kentucky Commission granted approval for the remaining transmission line CCN in May 2006. In August 2006, LG&E and KU obtained dismissal of a judicial review of such CCN approval by certain property owners. A further appeal of such dismissal was thereafter filed, which action remains pending. The transmission lines are also subject to routine regulatory filings and the right-of-way acquisition process. In November 2005, the Kentucky Division for Air Quality issued the final air permit, which was challenged via a request for remand in December 2005 by three environmental advocacy groups, including the Sierra Club. Administrative proceedings with respect to the challenge continued throughout 2006. A ruling may occur during the first half of 2007.

Market-Based Rate Authority. Beginning in April 2004, the FERC initiated proceedings to modify its methods used to assess generation market power and has established more stringent interim market screen tests. During 2005, in connection with LG&E's tri-annual market-based rate tariff renewals, the FERC continued to contend that the Company failed such market screens in certain regions. LG&E disputed this contention.

In July 2006, the FERC issued an Order in LG&E's market-based rate proceeding accepting LG&E's further proposal to address certain market power issues the FERC had claimed would arise upon an exit from the MISO. In particular, LG&E received permission to sell power at market-based rates at the interface of control areas in which they may be deemed to have market power, subject to a restriction that such power not be collusively re-sold back into such control areas. However, restrictions exist on sales by LG&E of power at market-based rates in the LG&E/KU and Big River Electric Corporation control areas. Certain general FERC proceedings continue with respect to market-based rate matters, and LG&E's market-based rate authority is subject to such future developments. LG&E cannot predict the ultimate impact of the current or potential mitigation mechanisms on its future wholesale power sales.

FERC Audit Results. In July 2006, the FERC issued a final report under a routine audit that its Office of Enforcement (formerly its Office of Market Oversight and Investigations) had conducted regarding the compliance of E.ON U.S. and subsidiaries, including LG&E, under the FERC's standards of conduct and codes of conduct requirements, as well as other areas. The final report contained certain findings calling for improvements in E.ON U.S. and subsidiaries' structures, policies and procedures relating to transmission, generation dispatch, energy marketing and other practices. E.ON U.S. and affiliates have agreed to certain corrective actions and have submitted procedures related to such corrective actions to the FERC. The corrective actions are in the nature of organizational and operational improvements as described above and are not expected to have a material adverse impact on the Company's results of operations or financial condition.

IRP. Integrated resource planning regulations in Kentucky require major utilities to make triennial IRP filings with the Kentucky Commission. In April 2005, LG&E and KU filed their joint 2005 IRP with the Kentucky Commission. The IRP provides historical and projected demand, resource and financial data, and other operating performance and system information. The AG and the KIUC were granted intervention in the IRP proceeding. The Kentucky Commission issued its staff report, with no substantive issues noted and closed the case by Order in February 2006.

PUHCA 2005. E.ON, LG&E's ultimate parent, is a registered holding company under PUHCA 2005 and was a registered holding company under PUHCA 1935. E.ON, its utility subsidiaries, including LG&E, and certain of its non-utility subsidiaries are subject to extensive regulation by the SEC and the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. LG&E believes that it has adequate authority (including financing authority) under existing FERC orders and regulations to conduct its business and will seek additional authorization when necessary.

EPAct 2005. The EPAct 2005 was enacted in August 2005. Among other matters, this comprehensive legislation contains provisions mandating improved electric reliability standards and performance; providing economic and other incentives relating to transmission, pollution control and renewable generation assets; increasing funding for clean coal generation incentives; repealing PUHCA 1935; enacting PUHCA 2005 and expanding FERC jurisdiction over public utility holding companies and related matters via the Federal Power Act and PUHCA 2005.

The FERC was directed by the EPAct 2005 to adopt rules to address many areas previously regulated by the other agencies under other statutes, including PUHCA 1935. The FERC is in various stages of rulemaking on these issues and LG&E is monitoring these rulemaking activities and actively participating in these and other rulemaking proceedings. LG&E is still evaluating the potential impacts of the EPAct 2005 and the associated rulemakings and cannot predict what impact the EPAct 2005, and any such rulemakings, will have on its operations or financial position.

In February 2006, the Kentucky Commission initiated an administrative proceeding to consider the requirements of the EPAct 2005, Subtitle E Section 1252, Smart Metering, which concerns time-based metering and demand response, and Section 1254, Interconnections. EPAct 2005 requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252, Smart Metering standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254, Interconnection standards within one year after the enactment of EPAct 2005. The Kentucky Commission held a public hearing in July 2006, in this proceeding with all Kentucky jurisdictional electric utilities. In December 2006, the Kentucky Commission issued an Order in this proceeding indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, all five Kentucky Commission jurisdictional utilities are required to file real-time pricing pilot programs for their large commercial and industrial customers. LG&E will develop a real-time pricing pilot for large industrial and commercial customers and file the details of the plan with the Kentucky Commission in April 2007.

As part of the rate case settlement agreements, and as referred to in the EPAct 2005 administrative order, LG&E made its pilot program filing, which addresses real-time pricing for residential and general service customers, in March 2007.

Hydro Upgrade. In October 2005, LG&E received from the FERC a new license to upgrade, operate and maintain the Ohio Falls Hydroelectric Project. The license is for a period of 40 years, effective November 2005. LG&E intends to spend approximately $76 million to refurbish the facility and add approximately 20 Mw of generating capacity over the next six years.

Note 3 - Financial Instruments

The cost and estimated fair values of LG&E's non-trading financial instruments as of December 31 follow:

(in millions)	2006 Carrying Value	2006 Fair Value	2005 Carrying Value	2005 Fair Value
Preferred stock subject to mandatory redemption (including current portion of $1 million)	$ 20	$ 20	$ 21	$ 21
Long-term debt (including current portion)	$574	$574	$574	$574
Long-term debt from affiliate	$225	$222	$225	$225
Interest-rate swaps - liability	$ (15)	$ (15)	$ (19)	$ (19)

All of the above valuations reflect prices quoted by exchanges except for the swaps and intercompany loans. The fair values of the swaps and intercompany loans reflect price quotes from dealers or amounts calculated using accepted pricing models. The fair values of cash and cash equivalents, accounts receivable, accounts payable and notes payable are substantially the same as their carrying values.

Interest Rate Swaps (hedging derivatives). LG&E uses over-the-counter interest rate swaps to hedge exposure to market fluctuations in certain of its debt instruments. Pursuant to Company policy, use of these financial instruments is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature. Management has designated all of the interest rate swaps as hedge instruments. Financial instruments designated as cash flow hedges have resulting gains and losses recorded within other comprehensive income and stockholders' equity. See Note 13, Accumulated Other Comprehensive Income. Financial instruments designated as fair value hedges and the underlying hedged items are periodically marked to market with the resulting net gains and losses recorded directly into net income. Upon termination of any fair value hedge, the resulting gain or loss is recorded into net income.

LG&E was party to various interest rate swap agreements with aggregate notional amounts of $211 million as of December 31, 2006 and 2005. Under these swap agreements, LG&E paid fixed rates averaging 4.38% and received variable rates based on London Interbank Borrowing Offer Rate or the Bond Market Association's municipal swap index averaging 3.75% and 3.15% at December 31, 2006 and 2005, respectively. The swap agreements in effect at December 31, 2006 have been designated as cash flow hedges and mature on dates ranging from 2020 to 2033. The cash flow designation was assigned because the underlying variable rate debt has variable future cash flows. The hedges have been deemed to be fully effective resulting in a pretax gain of $3 million for 2006 and a pre-tax loss of less than $1 million in 2005, recorded in other comprehensive income. Upon expiration of these hedges, the amount recorded in other comprehensive income will be reclassified into earnings. The amount expected to be reclassified from other comprehensive income to earnings in the next twelve months is less than $1 million. A deposit in the amount of $11 million, used as collateral for one of the interest rate swaps, is classified as restricted cash on the balance sheet. The amount of the deposit required is tied to the market value of the swap.

Energy Risk Management Activities (non-hedging derivatives). LG&E conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to hedge price risk and are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended. Prior to the MISO establishing its Day 2 energy market in April 2005, wholesale forward transactions were primarily physically settled and thus were treated as normal sales under SFAS No 133, as amended, and were not marked to market.

The table below summarizes LG&E's energy trading and risk management activities:

(in millions)	2006	2005
Fair value of contracts at beginning of period, net asset	$ 1	$ -
Fair value of contracts when entered into during the period	3	1
Contracts realized or otherwise settled during the period	(6)	-
Changes in fair values due to changes in assumptions	3	-
Fair value of contracts at end if period, net asset	$ 1	$ 1

No changes to valuation techniques for energy trading and risk management activities occurred during 2006 or 2005. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at December 31, 2006 and 2005, have a maturity of less than one year and are valued using prices actively quoted for proposed or executed transactions or quoted by brokers.

LG&E maintains policies intended to minimize credit risk and revalues credit exposures daily to monitor compliance with those policies. At December 31, 2006, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better.

LG&E hedges the price volatility of its forecasted electric off-system sales with the sales of market-traded electric forward contracts for periods of less than one year. These electric forward sales have been designated as cash flow hedges and are not speculative in nature. Gains or losses on these instruments, to the extent that the hedging relationship has been effective, are deferred in other comprehensive income. Gains and losses resulting from ineffectiveness are shown in the statements of income in other expense (income)-net. Upon completion of the underlying hedge transaction, the amount recorded in other comprehensive income is recorded in earnings. No material pre-tax gains and losses resulted from these cash flow hedges in 2006, 2005 and 2004. See Note 13, Accumulated Other Comprehensive Income.

Note 4 - Concentrations of Credit and Other Risk

Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed to perform as contracted. Concentrations of credit risk (whether on- or off-balance sheet) relate to groups of customers or counterparties that have similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

LG&E's customer receivables and natural gas and electric revenues arise from deliveries of natural gas to approximately 324,000 customers and electricity to approximately 398,000 customers in Louisville and adjacent areas in Kentucky. For the year ended December 31, 2006, 70% of total revenue was derived from electric operations and 30% from natural gas operations. For the year ended December 31, 2005, 69% of total revenue was derived from electric operations and 31% from natural gas operations.

In November 2005, LG&E and IBEW Local 2100 employees, that represent approximately 69% of LG&E's workforce at February 28, 2007, entered into a three-year collective bargaining agreement with annual benefits re-openers.

Note 5 - Pension and Other Postretirement Benefit Plans

LG&E has both funded and unfunded non-contributory defined benefit pension plans and other postretirement benefit plans that together cover substantially all of its employees. The healthcare plans are contributory with participants' contributions adjusted annually. LG&E uses December 31 as the measurement date for its plans.

Obligations and Funded Status. The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the three-year period ending December 31, 2006, and a statement of the funded status as of December 31 for LG&E's sponsored defined benefit plans:

(in millions)	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
Change in benefit obligation						
Benefit obligation at beginning of year	$ 427	$ 402	$ 379	$ 106	$ 113	$ 108
Service cost	4	4	3	1	1	1
Interest cost	23	22	23	6	6	7
Plan amendments	4	3	3	-	2	-
Benefits paid	(29)	(30)	(31)	(8)	(8)	(7)
Actuarial (gain) or loss and other	(21)	26	25	-	(8)	4
Benefit obligation at end of year	$ 408	$ 427	$ 402	$ 105	$ 106	$ 113
Change in plan assets						
Fair value of plan assets at beginning of year	$ 333	$ 338	$ 298	$ 3	$ 1	$ 1
Actual return on plan assets	36	27	39	-	-	(2)
Employer contributions	18	-	35	11	10	9
Benefits paid	(29)	(30)	(31)	(8)	(8)	(7)
Administrative expenses and other	(2)	(2)	(3)	-	-	-
Fair value of plan assets at end of year	$ 356	$ 333	$ 338	$ 6	$ 3	$ 1
Funded status at end of year	$ (52)	$ (94)	$ (64)	$ (99)	$ (103)	$ (112)

Amounts Recognized in Statement of Financial Position. The following tables provide the amounts recognized in the balance sheet and information for plans with benefit obligations in excess of plan assets as of December 31:

(in millions)	Pension Benefits 2006	Pension Benefits 2005	Other Postretirement Benefits 2006	Other Postretirement Benefits 2005
Prior to the application of SFAS No. 158:				
Accrued benefit liability	$ (35)	$ (77)	$ (66)	$ (67)
Intangible asset	27	31	-	-
Accumulated other comprehensive income	49	77	-	-
After the application of SFAS No. 158:				
Regulatory assets	93	-	33	-
Accrued benefit liability (current)	-	-	(2)	-
Accrued benefit liability (non-current)	(52)	(77)	(97)	(67)

The following table shows the calculation of the accrued benefit liability at December 31:

(in millions)	Pension Benefits 2006	Pension Benefits 2005	Other Postretirement Benefits 2006	Other Postretirement Benefits 2005
Funded status	$ (52)	$ (94)	$ (99)	$ (103)
Unrecognized prior service costs	N/A	-	N/A	10
Unrecognized actuarial loss	N/A	94	N/A	21
Unrecognized transition obligation	N/A	-	N/A	5
Other comprehensive income	N/A	(77)	N/A	-
Accrued benefit liability	$ (52)	$ (77)	$ (99)	$ (67)

Additional year-end information for plans with accumulated benefit obligations in excess of plan assets:

(in millions)	Pension Benefits 2006	Pension Benefits 2005	Other Postretirement Benefits 2006	Other Postretirement Benefits 2005
Benefit obligation	$ 408	$ 427	$ 105	$ 106
Accumulated benefit obligation	391	410	-	-
Fair value of plan assets	356	333	6	3

Components of Net Periodic Benefit Cost. The following table provides the components of net periodic benefit cost for the plans:

(in millions)	Pension Benefits 2006	Pension Benefits 2005	Pension Benefits 2004	Other Postretirement Benefits 2006	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004
Service cost	$ 4	$ 4	$ 3	$ 1	$ 1	$ 1
Interest cost	23	22	23	6	5	6
Expected return on plan assets	(27)	(26)	(27)	-	-	-
Amortization of prior service costs	4	4	4	2	2	2
Amortization of transitional asset	(1)	(1)	(1)	-	1	1
Amortization of actuarial loss	4	2	2	-	-	1
Amortization of transitional obligation	-	-	-	1	-	-
Benefit cost at end of year	$ 7	$ 5	$ 4	$ 10	$ 9	$ 11

The assumptions used in the measurement of LG&E's pension benefit obligation are shown in the following table:

	2006	2005	2004
Weighted-average assumptions as of December 31:			
Discount rate-Union plan	5.91%	5.50%	5.75%
Discount rate-Non-union plan	5.96%	5.50%	5.75%
Rate of compensation increase	5.25%	5.25%	4.50%

The assumptions used in the measurement of LG&E's net periodic benefit cost are shown in the following table:

	2006	2005	2004
Discount rate	5.50%	5.75%	6.25%
Expected long-term return on plan assets	8.25%	8.25%	8.50%
Rate of compensation increase	5.25%	4.50%	3.50%

To develop the expected long-term rate of return on assets assumption, LG&E considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio.

Assumed Healthcare Cost Trend Rates. For measurement purposes, a 10% annual increase in the per capita cost of covered healthcare benefits was assumed for 2006. The rate was assumed to decrease gradually to 5% by 2015 and remain at that level thereafter.

Assumed healthcare cost trend rates have a significant effect on the amounts reported for the healthcare plans. A 1% change in assumed healthcare cost trend rates would have resulted in an increase or decrease of less than $1 million on the 2006 total of service and interest costs components and an increase or decrease of $3 million in year-end 2006 postretirement benefit obligations.

Expected Future Benefit Payments. The following list provides the amount of expected future benefit payments, which reflect expected future service, as appropriate:

(in millions)	Pension Plans	Other Postretirement Benefits
2007	$ 28	$ 8
2008	$ 28	$ 9
2009	$ 27	$ 9
2010	$ 26	$ 9
2011	$ 25	$ 9
2012-16	$ 124	$ 44

Plan Assets. The following table shows LG&E's weighted-average asset allocation by asset category at December 31:

	Target Range	2006	2005	2004
Pension Plans:				
Equity securities	45% - 75%	61%	57%	66%
Debt securities	30% - 50%	39%	42%	33%
Other	0% - 10%	0%	1%	1%
Totals		100%	100%	100%

The investment policy of the pension plans was developed in conjunction with financial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the fund and maximize investment earnings. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, MSCI-EAFE Index, Lehman Aggregate and Lehman Long Duration Gov/Corporate Bond Index in proportions equal to the targeted asset allocation.

Evaluation of performance focuses on a long-term investment time horizon of at least three to five years or a complete market cycle. The assets of the pension plans are broadly diversified within different asset classes (equities, fixed income securities and cash equivalents).

To minimize the risk of large losses in a single asset class, no more than 5% of the portfolio will be invested in the securities of any one issuer with the exclusion of the U.S. government and its agencies. The equity portion of the fund is diversified among the market's various subsections to diversify risk, maximize returns and avoid undue exposure to any single economic sector, industry group or individual security. The equity subsectors include, but are not limited to, growth, value, small capitalization and international.

In addition, the overall fixed income portfolio may have an average weighted duration, or interest rate sensitivity which is within +/- 20% of the duration of the overall fixed income benchmark. Foreign bonds in the aggregate shall not exceed 10% of the total fund. The portfolio may include a limited investment of up to 20% in below investment grade securities provided that the overall average portfolio quality remains "AA" or better.

The below investment grade securities include, but are not limited to, medium-term notes, corporate debt, non-dollar and emerging market debt and asset backed securities. The cash investments should be in securities that either are of short maturities (not to exceed 180 days) or readily marketable with modest risk. Derivative securities are permitted only to improve the portfolio's risk/return profile, to modify the portfolio's duration or to reduce transaction costs and must be used in conjunction with underlying physical assets in the portfolio. Derivative securities that involve speculation, leverage, interest rate anticipation, or any undue risk whatsoever are not deemed appropriate investments.

The investment objective for the postretirement benefit plan is to provide current income consistent with stability of principal and liquidity while maintaining a stable net asset value of $1.00 per share. The postretirement funds are invested in a prime cash money market fund that invests primarily in a portfolio of short-term, high-quality fixed income securities issued by banks, corporations and the U.S. government.

Contributions. LG&E made discretionary contributions to the pension plan of $18 million in January 2006 and $35 million in January 2004. There were no contributions during 2005. LG&E made an additional discretionary contribution to the pension plan of $56 million in January 2007, which was slightly more than the $52 million accrued benefit liability as of December 31, 2006. LG&E does not expect to make any further contributions in 2007. See Note 15, Subsequent Events.

In addition, LG&E made contributions to other postretirement benefit plans of approximately $11 million, $10 million and $9 million in 2006, 2005 and 2004, respectively. In 2007, LG&E anticipates making voluntary contributions to fund the Voluntary Employee Beneficiary Association (VEBA) trusts to match the annual postretirement expense and funding the 401(h) plan up to certain maximum applicable amounts under law or regulation.

Pension Legislation. The Pension Protection Act of 2006 was enacted in August 2006. The new rules are generally effective for plan years beginning after 2008. Among other matters, this comprehensive legislation contains provisions applicable to defined benefit plans which generally (i) mandate 100% funding of current liabilities within seven years; (ii) increase tax-deduction levels regarding contributions; (iii) revise certain actuarial assumptions, such as mortality tables and discount rates; and (iv) raise federal insurance premiums and other fees for under-funded and distressed plans. The legislation also contains similar provisions relating to defined-contribution plans and qualified and non-qualified executive pension plans and other matters. While LG&E continues to examine the potential impacts of the Pension Protection Act of 2006, its $56 million contribution in January 2007 was slightly more than the accrued benefit liability as of December 31, 2006.

FSP 106-2. FSP 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003*, which provided guidance on accounting for subsidies provided under the Medicare Act, was effective for the first interim or annual period beginning after June 15, 2004. The impact of the subsidy in 2004 was a reduction in the accumulated postretirement benefit obligation of $3 million. The effect of the subsidy on the measurement of the net periodic postretirement benefit cost was less than $1 million.

Thrift Savings Plans. LG&E has a thrift savings plan under section 401(k) of the IRC. Under the plan, eligible employees may defer and contribute to the plan a portion of current compensation in order to provide future retirement benefits. LG&E makes contributions to the plan by matching a portion of the employee contributions. The costs of this matching were approximately $2 million for 2006 and 2005.

Note 6 - Income Taxes

Components of income tax expense are shown in the table below:

(in millions)		2006	2005	2004
Current	- federal	$60	$73	$34
	- state	11	10	13
Deferred	- federal – net	(7)	(12)	11
	- state – net	(1)	(2)	(1)
Investment tax credit-deferred		3	-	-
Amortization of investment tax credit		(4)	(4)	(4)
Total income tax expense		$62	$65	$53

Deferred federal income tax expense during 2004 included significant deductions attributable to federal bonus depreciation which ended after December 2004.

In June 2006, LG&E and KU filed a joint application with the DOE requesting certification to be eligible for investment tax credits applicable to the construction of TC2. The EPAct 2005 added Section 48A to the Internal Revenue Code, which provides for an investment tax credit to promote the commercialization of advanced coal technologies that will generate electricity in an environmentally responsible manner. LG&E's and KU's application requested up to a maximum amount of "advanced coal project" credit allowed per taxpayer, or $125 million, based on an estimate of 15% of projected qualifying TC2 expenditures.

In November 2006, the DOE and Internal Revenue Service announced that LG&E and KU were selected to receive the tax credit. LG&E's portion of the tax credit will be approximately $24 million over the construction period of TC2. This tax credit will be amortized to income over the life of the related property. In 2006, based on eligible construction expenditures incurred in 2006, LG&E recorded a federal investment tax credit, decreasing current federal income taxes in 2006 by $3 million.

H. R. 4520, known as the "American Jobs Creation Act of 2004" allows electric utilities to take a deduction of up to 3% of their qualified production activities income starting in 2005. This deduction reduced LG&E's effective tax rate by less than 1% for 2006.

Components of net deferred tax liabilities included in the balance sheet are shown below:

(in millions)	2006	2005
Deferred tax liabilities:		
Depreciation and other plant-related items	$367	$391
Regulatory assets and other	22	23
Pension and related benefits	6	-
Total deferred tax liabilities	395	414
Deferred tax assets:		
Investment tax credit	15	17
Income taxes due to customers	21	17
Pensions and related benefits	-	39
Liabilities and other	26	19
Total deferred tax assets	62	92
Net deferred income tax liability	$333	$322

A reconciliation of differences between the statutory U.S. federal income tax rate and LG&E's effective income tax rate follows:

	2006	2005	2004
Statutory federal income tax rate	35.0%	35.0%	35.0%
State income taxes, net of federal benefit	3.8	4.3	5.3
Reduction of income tax accruals	(0.4)	(2.0)	(0.7)
Amortization of investment tax credits	(2.2)	(2.1)	(3.6)
Other differences	(1.6)	(1.7)	(0.4)
Effective income tax rate	34.6%	33.5%	35.6%

State income taxes net of federal benefit in 2006 reflect Kentucky Coal Tax Credits earned.

Other differences primarily relate to excess deferred taxes which reflect the benefits of deferred taxes reversing at tax rates that differ from statutory rates and various other permanent differences.

In September 2005, LG&E received notice from the Congressional Joint Committee on Taxation approving the Internal Revenue Service's audit of LG&E's income tax returns for the periods December 1999 through December 2003. As a result of resolving numerous tax matters during these periods, LG&E reduced income tax accruals by $4 million during 2005.

Kentucky House Bill 272, also known as "Kentucky's Tax Modernization Plan", was signed into law in March 2005. This bill contains a number of changes in Kentucky's tax system, including the reduction of the Corporate income tax rate from 8.25% to 7% effective January 1, 2005, and a further reduction to 6% effective January 1, 2007. As a result of the income tax rate change, LG&E's deferred tax reserve amount will exceed its actual deferred tax liability attributable to existing temporary differences, since the new statutory rates are lower than the rates were when the deferred tax liability originated. This excess amount is referred to as excess deferred income taxes. In June 2005 and December 2006, LG&E received approval from the Kentucky Commission to establish and amortize a regulatory liability ($16 million) for its net excess deferred income tax balances. LG&E will amortize its depreciation-related excess deferred income tax balances under the average rate assumption method. The average rate assumption method matches the amortization of the excess deferred income taxes with the life of the timing differences to which they relate. Excess deferred income tax balances related to non-depreciation timing differences were expensed in 2005 and 2006 due to their immaterial amount.

LG&E expects to have adequate levels of taxable income to realize its recorded deferred tax assets.

Note 7 - Long-Term Debt

As of December 31, 2006 and 2005, long-term debt and the current portion of long-term debt consist primarily of pollution control bonds and long-term loans from affiliated companies as summarized below.

(in millions)	Stated Interest Rates	Maturities	Principal Amounts
Outstanding at December 31, 2006:			
Noncurrent portion	Variable - 5.875%	2008-2035	$ 572
Current portion	Variable	2007-2027	248
Outstanding at December 31, 2005:			
Noncurrent portion	Variable - 5.875%	2008-2035	$ 573
Current portion	Variable	2006-2027	248

Under the provisions for LG&E's variable-rate pollution control bonds, Series S, T, U, BB, CC, DD and EE, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events, causing the bonds to be classified as current portion of long-term debt in the balance sheets. The average annualized interest rate for these bonds during 2006 and 2005 was 3.50% and 2.50%, respectively.

Pollution control series bonds are first mortgage bonds that have been issued by LG&E in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates LG&E to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. The county's debt is also secured by LG&E's first mortgage bonds of an equal amount (the pollution control series bonds) that are pledged to the trustee for the pollution control revenue bonds, and that matches the terms and conditions of the county's debt, but require no payment of principal and interest unless LG&E defaults on the loan agreement.

Substantially all of LG&E's utility assets are pledged as collateral for its first mortgage bonds. LG&E's first mortgage bond indenture, as supplemented, provides that portions of retained earnings will not be available for the payment of dividends on common stock, under certain specified conditions. No portion of retained earnings was restricted by this provision as of either December 31, 2006 or 2005.

Interest rate swaps are used to hedge LG&E's underlying variable-rate debt obligations. These swaps hedge specific debt issuances and, consistent with management's designation, are accorded hedge accounting treatment. The swaps exchange floating-rate interest payments for fixed rate interest payments to reduce the impact of interest rate changes on LG&E's pollution control bonds. As of December 31, 2006 and 2005, LG&E had swaps with an aggregate notional value of $211 million. See Note 3, Financial Instruments.

Redemptions and maturities of long-term debt for 2006, 2005 and 2004 are summarized below:

($ in millions) Year	 Description	Principal Amount	 Rate	Secured/ Unsecured	 Maturity
2006	Mandatorily Redeemable Preferred Stock	$ 1	5.875%	Unsecured	Jul 2006
2005	Pollution control bonds	$ 40	5.90%	Secured	Apr 2023
2005	Due to Fidelia	$ 50	1.53%	Secured	Jan 2005
2005	Mandatorily Redeemable Preferred Stock	$ 1	5.875%	Unsecured	Jul 2005
2004	Due to Fidelia	$ 50	1.53%	Secured	Jan 2005
2004	Mandatorily Redeemable Preferred Stock	$ 1	5.875%	Unsecured	Jul 2004

LG&E did not issue any new long-term debt in 2006. Issuances of long-term debt for 2005 and 2004 are summarized below:

($ in millions) Year	 Description	Principal Amount	 Rate	Secured/ Unsecured	 Maturity
2005	Pollution control bonds	$ 40	Variable	Secured	Feb 2035
2004	Due to Fidelia	$ 25	4.33%	Secured	Jan 2012
2004	Due to Fidelia	$100	1.53%	Secured	Jan 2005

LG&E has existing $5.875 series mandatorily redeemable preferred stock outstanding having a current redemption price of $100 per share. The preferred stock has a sinking fund requirement sufficient to retire a minimum of 12,500 shares on July 15 of each year commencing with July 15, 2003, and the remaining 187,500 shares on July 15, 2008 at $100 per share. LG&E redeemed 12,500 shares in accordance with these provisions on July 15, 2006, 2005, 2004 and 2003, leaving 200,000 shares currently outstanding.

Long-term debt maturities for LG&E are shown in the following table:

(in millions)	
2007	$ 1
2008	19
2009-11	-
Thereafter	800 (a)
Total	$820

(a) Includes long-term debt of $246 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. Maturity dates for these bonds range from 2013 to 2027. LG&E does not expect to pay these amounts in 2007.

Note 8 - Notes Payable and Other Short-Term Obligations

LG&E participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds available to LG&E at market-based rates (based on an index of highly rated commercial paper issues) up to $400 million.

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2006	$400	$ 68	$332	5.25%
December 31, 2005	$400	$141	$259	4.21%

At December 31, 2006 and 2005, E.ON U.S. maintained a revolving credit facility totaling $200 million with an affiliated company, E.ON North America, Inc., to ensure funding availability for the money pool. The balance is as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2006	$200	$102	$98	5.49%
December 31, 2005	$200	$105	$95	4.49%

During June 2006, LG&E renewed five revolving lines of credit with banks totaling $185 million. These credit facilities expire in June 2007, and there was no outstanding balance under any of these facilities at December 31, 2006 and 2005.

The covenants under these revolving lines of credit include:

- The debt/total capitalization ratio must be less than 70%;
- E.ON AG must own at least 66.667% of voting stock of LG&E directly or indirectly;
- The corporate credit rating of the Company must be at or above BBB- and Baa3; and
- A limitation on disposing of assets aggregating more than 15% of total assets as of December 31, 2004.

Note 9 - Commitments and Contingencies

Operating Leases. LG&E leases office space, office equipment and vehicles and accounts for these leases as operating leases. Total lease expense for 2006, 2005 and 2004, less amounts contributed by affiliated companies occupying a portion of the office space leased by LG&E, was $5 million for 2006 and $3 million each for 2005 and 2004. The future minimum annual lease payments for operating leases for years subsequent to December 31, 2006, are shown in the following table:

(in millions)	
2007	$2
2008	2
2009	2
2010	2
2011	2
Thereafter	8
Total	$18

Sale and Leaseback Transaction. LG&E is a participant in a sale and leaseback transaction involving its 38% interest in two jointly-owned combustion turbines at KU's E.W. Brown generating station (Units 6 and 7). Commencing in December 1999, LG&E and KU entered into a tax-efficient, 18-year lease of the combustion turbines. LG&E and KU have provided funds to fully defease the lease, and have executed an irrevocable notice to exercise an early purchase option contained in the lease after 15.5 years. The financial statement treatment of this transaction is no different than if LG&E had retained its ownership. The leasing transaction was entered into following receipt of required state and federal regulatory approvals.

In case of default under the lease, LG&E is obligated to pay to the lessor its share of certain fees or amounts. Primary events of default include loss or destruction of the combustion turbines, failure to insure or maintain the combustion turbines and unwinding of the transaction due to governmental actions. No events of default currently exist with respect to the lease. Upon any termination of the lease, whether by default or expiration of its term, title to the combustion turbines reverts jointly to LG&E and KU.

At December 31, 2006, the maximum aggregate amount of default fees or amounts was $9 million, of which LG&E would be responsible for 38% (approximately $3 million). LG&E has made arrangements with E.ON U.S., via guarantee and regulatory commitment, for E.ON U.S. to pay LG&E's full portion of any default fees or amounts.

Letters of Credit. LG&E has provided letters of credit totaling $3 million to support certain obligations related to landfill reclamation and a letter of credit totaling less than $1 million to support certain obligations related to workers' compensation.

Purchased Power. LG&E has a contract for purchased power with OVEC for various Mw capacities. LG&E has an investment of 5.63% ownership in OVEC's common stock, which is accounted for on the cost method of accounting. LG&E's share of OVEC's output is 5.63%, approximately 124 Mw of generation capacity. Future obligations for power purchases are shown in the following table:

(in millions)	
2007	$ 11
2008	13
2009	16
2010	17
2011	17
Thereafter	328
Total	$402

Construction Program. LG&E had approximately $180 million of commitments in connection with its construction program at December 31, 2006.

In June 2006, the LG&E and KU entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights.

Environmental Matters. LG&E's operations are subject to a number of environmental laws and regulations, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to LG&E's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as national ambient air quality standards ("NAAQS"). Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a State Implementation Plan ("SIP") to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85 percent from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, in 2002, Kentucky amended its SIP to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which requires additional SO_2 emission reductions of 70 percent and NOx emission reductions of 65 percent from 2003 levels. The CAIR provides for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. The final rule is currently under challenge in a number of federal court proceedings. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, LG&E's power plants are potentially subject to additional reductions in SO_2 and NOx emissions.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provides for reductions of 70 percent from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets will be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR. The final rule is also currently under challenge in the federal courts. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAMR. In addition, in 2005 and 2006, state and local air agencies in Kentucky have proposed or adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants. To the extent those rules are final, they are not expected to have a material impact on LG&E's power plant operations.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its Clean Air Visibility Rule detailing how the Clean Air Act's best available retrofit technology ("BART") requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR will result in more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. LG&E had previously installed flue gas desulfurization equipment on all of its generating units prior to the effective date of the acid rain program. LG&E's strategy for its Phase II SO_2 requirements, which commenced in 2000, is to use accumulated emissions allowances to defer additional capital expenditures and LG&E will continue to evaluate improvements to further reduce SO_2 emissions. In order to achieve the NOx emission reductions mandated by the NOx SIP Call, LG&E installed additional NOx controls, including selective catalytic reduction technology, during the 2000 to 2006 time period at a cost of $187 million. In 2001, the Kentucky Commission granted recovery in principal of these costs incurred by LG&E under its periodic environmental surcharge review mechanisms.

In order to achieve the emissions reductions mandated by the CAIR and CAMR, LG&E expects to incur additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted recovery in principal of these costs incurred by LG&E under its periodic environmental surcharge review mechanisms. LG&E believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. LG&E's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. LG&E will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are ongoing. In addition, litigation is currently pending before various courts to determine whether the EPA and the states have the authority to regulate GHG emissions under existing law. LG&E is monitoring ongoing efforts to enact GHG reduction requirements at the state and federal level. LG&E is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted or to determine the reduction targets and deadlines that would be applicable under such programs. As a Company with significant coal-fired generating assets, LG&E could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of LG&E cannot be determined prior to the enactment of such programs.

General Environmental Proceedings. From time to time, LG&E appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include remediation obligations for former MGP sites;

liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; ongoing claims regarding alleged particulate emissions from LG&E's Cane Run station; and ongoing claims regarding GHG emissions from LG&E's generating stations. With respect to the former MGP sites, LG&E has estimated that it could incur additional costs of less than $1 million for remaining clean-up activities under existing approved plans or agreements. An accrual for this amount had been recorded in the accompanying financial statements at December 31, 2005, which accrual was reversed as of December 31, 2006 upon the evaluation that the likelihood of such occurrence is remote. Based on analysis to date, the resolution of the other matters is also not expected to have a material impact on the operations of LG&E.

Note 10 - Jointly Owned Electric Utility Plant

LG&E owns a 75% undivided interest in TC1 which the Kentucky Commission has allowed to be reflected in customer rates. Of the remaining 25% of the Unit, IMEA owns a 12.12% undivided interest, and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate ownership share of fuel cost, operation and maintenance expenses and incremental assets. The following data represent shares of the jointly owned property:

	TC1			
	LG&E	IMPA	IMEA	Total
Ownership interest	75%	12.88%	12.12%	100%
Mw capacity	383	66	62	511

(in millions)	
LG&E's 75% ownership:	
Cost	$ 604
Accumulated depreciation	(231)
Net book value	$ 373
Construction work in progress (included in above)	$ 9

LG&E and KU have begun construction of another jointly owned unit at the Trimble County site. LG&E and KU own undivided 14.25% and 60.75% interests, respectively, in TC2. Of the remaining 25% of TC2, IMEA owns a 12.12% undivided interest and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate share of capital cost during construction, and fuel, operation and maintenance cost when TC2 begins operation, which is expected to occur in 2010.

	TC2				
	LG&E	KU	IMPA	IMEA	Total
Ownership interest	14.25%	60.75%	12.88%	12.12%	100%
Mw capacity	107	455	97	91	750

(in millions)	LG&E	KU
Construction work in progress	$25	$96

LG&E and KU jointly own the following combustion turbines and related equipment:

($ in millions)	LG&E				KU				Total			
Ownership Percentage	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value
LG&E 53%, KU 47% (1)	146	58	(10)	48	129	51	(10)	41	275	109	(20)	89
LG&E 38%, KU 62% (2)	118	46	(8)	38	190	72	(12)	60	308	118	(20)	98
LG&E 29%, KU 71% (3)	92	32	(4)	28	228	80	(12)	68	320	112	(16)	96
LG&E 37%, KU 63% (4)	236	79	(8)	71	404	137	(12)	125	640	216	(20)	196
LG&E 29%, KU 71% (5)	n/a	3	(0)	3	n/a	9	(1)	8	n/a	12	(1)	11

(1) Comprised of Paddy's Run 13 and E.W. Brown 5. In addition to the above jointly owned utility plant, there is an inlet air cooling system attributable to Unit 5 and Units 8-11 at the E.W. Brown facility. This inlet air cooling system is not jointly owned, however it is used to increase production on the units to which it relates, resulting in an additional 10Mw of capacity for LG&E.
(2) Comprised of units 6 and 7 at the E.W. Brown facility.
(3) Comprised of units 5 and 6 at the Trimble County facility.
(4) Comprised of CT Substation 7-10 and units 7, 8, 9 and 10 at the Trimble County facility.
(5) Comprised of CT Substation 5 and 6 and CT Pipeline at the Trimble County facility.

Both LG&E's and KU's participating share of direct expenses of the joint fuel plants is included in the corresponding operating expenses on its respective income statement (e.g., fuel, maintenance of plant, other operating expense).

Note 11 - Segments of Business and Related Information

LG&E is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity and the storage, distribution and sale of natural gas. LG&E is regulated by the Kentucky Commission and files electric and natural gas financial information separately with the Kentucky Commission. The Kentucky Commission establishes rates specifically for the electric and natural gas businesses. Therefore, management reports and analyzes financial performance based on the electric and natural gas segments of the business. Financial data for business segments follow:

(in millions)	Electric	Gas	Total
2006			
Operating revenues	$ 943	$395	$1,338
Depreciation and amortization	105	19	124
Income taxes	57	5	62
Interest income	1	-	1
Interest expense	33	8	41
Net income	107	10	117
Total assets	2,520	664	3,184
Construction expenditures	111	35	146

2005			
Operating revenues	$ 987	$437	$1,424
Depreciation and amortization	106	18	124
Income taxes	60	5	65
Interest income	1	-	1
Interest expense	30	7	37
Net income	119	10	129
Total assets	2,475	671	3,146
Construction expenditures	97	42	139
2004			
Operating revenues	$ 816	$357	$1,173
Depreciation and amortization	100	17	117
Income taxes	48	5	53
Interest income	-	-	-
Interest expense	27	6	33
Net income	87	9	96
Total assets	2,417	550	2,967
Construction expenditures	113	35	148

Note 12 - Related Party Transactions

LG&E and other subsidiaries of E.ON engage in related party transactions. Transactions between LG&E and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between LG&E and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

LG&E and KU purchase energy from each other in order to effectively manage the load of their retail and off-system customers. In 2004, LG&E also had sales to LG&E Energy Marketing Inc., another E.ON U.S. subsidiary, of less than $1 million. These sales and purchases are included in the statements of income as electric operating revenues and purchased power operating expense. LG&E intercompany electric revenues and purchased power expense for the years ended December 31, 2006, 2005 and 2004 were as follows:

(in millions)	2006	2005	2004
Electric operating revenues from KU	$99	$92	$59
Purchased power from KU	77	96	62

Interest Charges

See Note 8, Notes Payable and Other Short-Term Obligations, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

LG&E's intercompany interest income and expense for the years ended December 31, 2006, 2005 and 2004 were as follows:

(in millions)	2006	2005	2004
Interest on money pool loans	$ 2	$ 2	$ -
Interest on Fidelia loans	11	11	12

Other Intercompany Billings

E.ON U.S. Services provides LG&E with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. on behalf of LG&E, labor and burdens of E.ON U.S. Services employees performing services for LG&E and vouchers paid by E.ON U.S. Services on behalf of LG&E. The cost of these services are directly charged to LG&E, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, LG&E and KU provide services to each other and to E.ON U.S. Services. Billings between LG&E and KU relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned combustion turbines and other miscellaneous charges. Billings from LG&E to E.ON U.S. Services relate to information technology-related services provided by LG&E employees, cash received by E.ON U.S. Services on behalf of LG&E and services provided by LG&E to other non-regulated businesses which are paid through E.ON U.S. Services.

Intercompany billings to and from LG&E for the years ended December 31, 2006, 2005 and 2004 were as follows:

(in millions)	2006	2005	2004
E.ON U.S. Services billings to LG&E	$230	$208	$191
LG&E billings to KU	53	101	60
KU billings to LG&E	56	29	7
LG&E billings to E.ON U.S. Services	7	8	13

Note 13 – Accumulated Other Comprehensive Income

Accumulated other comprehensive income (loss) consisted of the following:

(in millions)	Minimum Pension Liability Adjustment	Accumulated Derivative Gain or Loss	Pre-Tax	Income Taxes	Net
Balance at December 31, 2003	$(48)	$(16)	$(64)	$27	$(37)
Minimum pension liability adjustment	(10)	-	(10)	4	(6)
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	-	(2)	(2)	-	(2)
Balance at December 31, 2004	(58)	(18)	(76)	31	(45)
Minimum pension liability adjustment	(19)	-	(19)	6	(13)
Balance at December 31, 2005	(77)	(18)	(95)	37	(58)
Minimum pension liability adjustment	77	-	77	(30)	47
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	-	3	3	(1)	2
Balance at December 31, 2006	$ -	$(15)	$(15)	$ 6	$ (9)

Note 14 – Notes to Statement of Cash Flows

Supplemental disclosures of cash flow information

(in millions)	2006	2005
Cash paid during the year for:		
Income Taxes	$ 64	$ 83
Interest on borrowed money	24	21
Interest on affiliated companies on borrowed money	11	13

Note 15 - Notes to Statement of Income for the Year

See page 115, line 6, column (g). Electric Utility Depreciation Expense includes $6.1 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 6, column (i). Gas Utility Depreciation Expense includes $2.1 million applicable to Common Utility Plant apportioned to Gas Operations.

See page 115, line 8, column (g). Electric Utility Amortization and Depletion of Utility Plant includes $4.3 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 8, column (i). Gas Utility Amortization and Depletion of Utility Plant includes $1.5 million applicable to Common Utility Plant apportioned to Gas Operations.

Note 16 - Subsequent Events

On January 16, 2007, LG&E made a discretionary contribution to the pension plan in the amount of $56 million, which was slightly more than the $52 million accrued benefit liability as of December 31, 2006.

On January 31, 2007, LG&E received an Order from the Kentucky Commission approving the charges and credits billed through the ECR during the review period as well as approving billing adjustments, a roll-in to base rates, revisions to the monthly surcharge filing and a rate of return on capital.

On January 31, 2007, the Kentucky Commission issued an Order approving LG&E's application for certain financial transactions, including arrangements which provide a source of funds for the possible redemption of LG&E's preferred stock. In March 2007, a committee of LG&E's board authorized the redemption of the preferred stock, effective on April 16, 2007, pursuant to existing redemption provisions applicable to such series. LG&E will redeem on such redemption date all of its outstanding shares of its series of preferred stock at the following redemption prices, respectively, plus an amount equal to accrued and unpaid dividends to the redemption date:

- 860,287 shares of 5% cumulative preferred stock (par value $25 per share) at $28 per share;
- 200,000 shares of $5.875 cumulative preferred stock (without par value) at $100 per share; and
- 500,000 shares of auction rate, series A, cumulative preferred stock (without par value) at $100 per share.

Dividends on the shares of preferred stock shall cease to accumulate on the redemption date and no further dividends will be paid or will accrue on such preferred stock thereafter.

On February 9, 2007, LG&E filed with the Kentucky Commission an application for approval of a "green energy" rider. This application details LG&E's plans to offer its customers a "green energy" program that contributes funds to the maintenance and growth of renewable energy in Kentucky and contiguous states. An Order is expected during the second quarter of 2007.

On March 21, 2007, LG&E filed a real-time pilot program for residential and general service customers with the Kentucky Commission as agreed to in the Rate Case settlement agreement and in response to additional requirements ordered by the Kentucky Commission resulting from not adopting the Smart-Metering and Interconnection standards included in the EPAct 2005. An order from the Kentucky Commission is anticipated before the end of 2007.

LG&E has commenced a review of certain federal and state permitting, licensing and oversight matters relating to existing natural gas operations at its Doe Run, Kentucky storage field. The review relates, in part, to the applicable jurisdictional status of such operations under the Natural Gas Act and whether additional applications, filings or exemptions are required or advisable, and is planned to be completed during mid-2007. LG&E has had preliminary communications with FERC and relevant regulatory agencies in Kentucky and Indiana and is continuing to coordinate with such entities. LG&E believes that no sanctions are warranted but is unable to estimate the ultimate outcome of the matter, including whether FERC might seek to impose any fines or penalties under the Energy Policy Act of 2005.

In April 2007, LG&E entered into two long-term borrowing arrangements with Fidelia in aggregate principal amount of $138 million. The loan proceeds were used to fund the preferred stock redemption and to repay certain short-term loans incurred to fund the pension contribution made by LG&E during the first quarter of 2007.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(46,923,505)		(3,599,009)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year		(46,923,505)		(3,599,009)
6	Balance of Account 219 at Beginning of Current Year		(46,923,505)		(3,599,009)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		46,923,505		
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)		46,923,505		
10	Balance of Account 219 at End of Current Quarter/Year				(3,599,009)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(7,647,316)		(58,169,830)		
2					
3					
4				128,935,060	128,935,060
5	(7,647,316)		(58,169,830)		
6	(7,647,316)		(58,169,830)		
7			46,923,505		
8	1,940,668		1,940,668		
9	1,940,668		48,864,173	116,828,596	165,692,769
10	(5,706,648)		(9,305,657)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (f) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	3,903,216,364	3,199,114,843
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,903,216,364	3,199,114,843
9	Leased to Others		
10	Held for Future Use	706,274	706,274
11	Construction Work in Progress	217,873,410	154,377,559
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	4,121,796,048	3,354,198,676
14	Accum Prov for Depr, Amort, & Depl	1,766,590,602	1,487,732,250
15	Net Utility Plant (13 less 14)	2,355,205,446	1,866,466,426
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,751,213,044	1,487,732,150
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	15,377,558	100
22	Total In Service (18 thru 21)	1,766,590,602	1,487,732,250
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,766,590,602	1,487,732,250

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/31/2007	End of 2006/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
524,410,592				179,690,929	3
					4
					5
					6
					7
524,410,592				179,690,929	8
					9
					10
54,810,960				8,684,891	11
					12
579,221,552				188,375,820	13
195,902,252				82,956,100	14
383,319,300				105,419,720	15
					16
					17
195,901,452				67,579,442	18
					19
					20
800				15,376,658	21
195,902,252				82,956,100	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
195,902,252				82,956,100	33

Name of Respondent	This Report Is:	Date of Report (Mo,Da,Yr)	Year of Report
Louisville Gas and Electric Company	(1) [x] An Original (2) [ ] A Resubmission	03/31/2007	Dec. 31, 2006

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold; Account 103, ExperimentalGas Plant Unclassified; and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	301 Organization		
3	302 Franchises and Consents	1,187	
4	303 Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	1,187	
6	2. PRODUCTION PLANT		
7	Natural Gas Production and Gathering Plant		
8	325.1 Producing Lands		
9	325.2 Producing Leaseholds		
10	325.3 Gas Rights		
11	325.4 Rights-of-Way		
12	325.5 Other Land and Land Rights		
13	326 Gas Well Structures		
14	327 Field Compressor Station Structures		
15	328 Field Meas. and Reg. Sta. Structures		
16	329 Other Structures		
17	330 Producing Gas Wells - Well Construction		
18	331 Producing Gas Wells - Well Equipment		
19	332 Field Lines		
20	333 Field Compressor Station Equipment		
21	334 Field Meas. and Reg. Sta. Equipment		
22	335 Drilling and Cleaning Equipment		
23	336 Purification Equipment		
24	337 Other Equipment		
25	338 Unsuccessful Exploration & Devel. Costs		
26	TOTAL Production and Gathering Plant		
27	Products Extraction Plant		
28	340 Land and Land Rights		
29	341 Structures and Improvements		
30	342 Extraction and Refining Equipment		
31	343 Pipe Lines		
32	344 Extracted Products Storage Equipment		
33	345 Compressor Equipment		
34	346 Gas Meas. and Reg. Equipment		
35	347 Other Equipment		
36	TOTAL Products Extraction Plant		
37	TOTAL Nat. Gas Production Plant		
38	Mfd. Gas Prod. Plant (Submit Suppl. Statement)		
39	TOTAL Production Plant		

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr) 03/31/2007	Year of Report Dec. 31, 2006

and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.
8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
				301	2
			1,187	302	3
				303	4
			1,187		5
					6
					7
				325.1	8
				325.2	9
				325.3	10
				325.4	11
				325.5	12
				326	13
				327	14
				328	15
				329	16
				330	17
				331	18
				332	19
				333	20
				334	21
				335	22
				336	23
				337	24
				338	25
					26
					27
				340	28
				341	29
				342	30
				343	31
				344	32
				345	33
				346	34
				347	35
					36
					37
					38
					39

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr) 03/31/2007	Year of Report Dec. 31, 2006

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
40	3. NATURAL GAS STORAGE AND PROCESSING PLANT		
41	Underground Storage Plant		
42	350.1 Land	32,865	
43	350.2 Rights-of-Way	63,678	
44	351 Structures and Improvements	2,920,265	28,134
45	352 Wells	8,814,484	
46	352.1 Storage Leaseholds and Rights	548,241	
47	352.2 Reservoirs	400,511	
48	352.3 Non-recoverable Natural Gas	9,648,855	
49	353 Lines	12,257,500	657,685
50	354 Compressor Station Equipment	14,135,898	199,132
51	355 Measuring and Reg. Equipment	383,613	11,340
52	356 Purification Equipment	10,103,108	44,793
53	357 Other Equipment	1,038,704	(681)
54	358 Asset Retire Obligations Gas Plant	504,098	37,034
55	TOTAL Underground Storage Plant	60,851,820	977,437
56	Other Storage Plant		
57	360 Land and Land Rights		
58	361 Structures and Improvements		
59	362 Gas Holders		
60	363 Purification Equipment		
61	363.1 Liquefaction Equipment		
62	363.2 Vaporizing Equipment		
63	363.3 Compressor Equipment		
64	363.4 Meas. and Reg. Equipment		
65	363.5 Other Equipment		
66	TOTAL Other Storage Plant		
67	Base Load Liquefied Natural Gas Terminating and Processing Plant		
68	364.1 Land and Land Rights		
69	364.2 Structures and Improvements		
70	364.3 LNG Processing Terminal Equipment		
71	364.4 LNG Transportation Equipment		
72	364.5 Measuring and Regulating Equipment		
73	364.6 Compressor Station Equipment		
74	364.7 Communications Equipment		
75	364.8 Other Equipment		
76	TOTAL Base Load Liquefied Natural Gas,		
77	Terminating and Processing Plant		
78	TOTAL Nat. Gas Storage and Proc. Plant	60,851,820	977,437
79	4. TRANSMISSION PLANT		
80	365.1 Land and Land Rights		
81	365.2 Rights-of-Way	220,660	
82	366 Structures and Improvements		
83	367 Mains	12,681,769	
84	368 Compressor Station Equipment		
85	369 Measuring and Reg. Sta. Equipment		
86	370 Communication Equipment		
87	371 Other Equipment		
88	TOTAL Transmission Plant	12,902,429	
89			
90			
91			
92			
93			
94			

Name of Respondent	This Report Is:	Date of Report (Mo,Da,Yr)	Year of Report
Louisville Gas and Electric Company	(1) [x] An Original (2) [ ] A Resubmission	03/31/2007	Dec. 31, 2006

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					40
					41
			32,865	350.1	42
			63,678	350.2	43
4,843			2,943,556	351	44
48,825			8,765,659	352	45
			548,241	352.1	46
			400,511	352.2	47
			9,648,855	352.3	48
128,441			12,786,744	353	49
373,259			13,961,771	354	50
7,143			387,810	355	51
213,645			9,934,256	356	52
4,812			1,033,211	357	53
			541,132	358	54
780,968			61,048,289		55
					56
				360	57
				361	58
				362	59
				363	60
				363.1	61
				363.2	62
				363.3	63
				363.4	64
				363.5	65
					66
					67
				364.1	68
				364.2	69
				364.3	70
				364.4	71
				364.5	72
				364.6	73
				364.7	74
				364.8	75
					76
					77
780,968			61,048,289		78
					79
				365.1	80
			220,660	365.2	81
				366	82
8,338			12,673,431	367	83
				368	84
				369	85
				370	86
				371	87
8,338			12,894,091		88
					89
					90
					91
					92
					93
					94

Name of Respondent	This Report Is:	Date of Report	Year of Report
Louisville Gas and Electric Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo,Da,Yr) 03/31/2007	Dec. 31, 2006

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
95	5. DISTRIBUTION PLANT		
96	374 Land and Land Rights	136,061	
97	375 Structures and Improvements	997,057	15,450
98	376 Mains	255,102,583	7,355,027
99	377 Compressor Station Equipment		
100	378 Meas. and Reg. Sta. Equip. - General	8,185,410	295,130
101	379 Meas. and Reg. Sta. Equip. - City Gate	3,804,864	52,151
102	380 Services	124,500,012	866,420
103	381 Meters	20,289,467	2,482,165
104	382 Meter Installations	6,689,545	2,986,356
105	383 House Regulators	3,814,800	1,160,605
106	384 House Reg. Installations	2,152,161	2,637,85[illegible]
107	385 Industrial Meas. and Reg. Sta. Equipment	159,361	
108	386 Other Prop. on Customers' Premises		
109	387 Other Equipment	65,052	
110	388 Asset Retirement Obligations Gas Plant	30,769	
111	TOTAL Distribution Plant	425,927,142	17,851,160
112	6. GENERAL PLANT		
113	389 Land and Land Rights		
114	390 Structures and Improvements		
115	391 Office Furniture and Equipment		
116	392 Transportation Equipment	3,370,224	18,793
117	393 Stores Equipment		
118	394 Tools, Shop, and Garage Equipment	3,202,512	307,243
119	395 Laboratory Equipment	435,068	13,204
120	396 Power Operated Equipment	2,739,306	309,700
121	397 Communication Equipment		
122	398 Miscellaneous Equipment		
123	Subtotal	9,747,110	648,940
124	399 Other Tangible Property		
125	TOTAL General Plant	9,747,110	648,940
126	TOTAL (Accounts 101 and 106)	509,429,688	19,477,537
127	Gas Plant Purchased (See Instr. 8)		
128	(Less) Gas Plant Sold (See Instr. 8)		
129	Experimental Gas Plant Unclassified		
130	TOTAL Gas Plant in Service	509,429,688	19,477,537

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr) 03/31/2007	Year of Report Dec. 31, 2006

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					95
			136,061	374	96
283,133			729,374	375	97
123,038			262,334,572	376	98
				377	99
627,150			7,853,390	378	100
10,470			3,846,545	379	101
340			125,366,092	380	102
1,599,912			21,171,720	381	103
539,557			9,136,344	382	104
377,313			4,598,092	383	105
82,659			4,707,358	384	106
			159,361	385	107
				386	108
13,939			51,113	387	109
			30,769	388	110
3,657,511			440,120,791		111
					112
				389	113
				390	114
				391	115
1,331			3,387,686	392	116
				393	117
34,977			3,474,778	394	118
8,759			439,513	395	119
4,749			3,044,257	396	120
				397	121
				398	122
49,816			10,346,234		123
				399	124
49,816			10,346,234		125
4,496,633			524,410,592		126
					127
					128
					129
4,496,633			524,410,592		130

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo,Da,Yr)	Year of Report
Louisville Gas and Electric Company	(1) [x] An Original (2) [ ] A Resubmission	3/31/2007	Dec. 31, 2006

CONSTRUCTION WORK IN PROGRESS-GAS (ACCOUNT 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform Systems of Accounts).
3. Minor projects (less than $500,000) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1			
2	Underground Storage		
3			
4	Minor Projects	2,812,338	
5	Total - Underground Storage	2,812,338	
6			
7	Transmission		
8			
9	Minor Projects	424,563	
10	Total- Transmission	424,563	
11			
12	Distribution		
13			
14	Large Scale Main Replacements	11,091,524	
15	Replace Co. Gas Service RC419	7,236,515	
16	New Business Connect Service RC419	6,869,771	
17	Gas Main Extension RC406	5,193,235	
18	New Business Subdivision RC341 UG	4,041,754	
19	Priority Main Replacement	2,449,680	
20	Mt. Washington/Lebanon Junction High System Upgrade	2,300,344	
21	New Business Connect Service RC419	2,186,223	
22	Muldraugh Dehydrator #2	1,000,617	
23	Public Works Gas RC406	912,105	
24	New Business Gas Service RC402	824,570	
25	Leak Repair RC419	597,571	
26	Riverport Reinforcement	570,467	
27	Pipeline Integrity Compliance	519,989	
28	Highway Relocations Gas Central	509,451	
29			
30	Minor Projects	4,668,532	
31	Total - Distribution	50,972,348	
32			
33	General Plant		
34			
35	Minor Projects	601,711	
36	Total - General Plant	601,711	
37			
38	Grand Total	54,810,960	
39			
40			

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr) 03/31/2007	Year of Report Dec. 31, 2006

General Description of Contruction Overhead Procedure

1. For each construction overhead explain: (a) the nature and extent of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Gas Plan Instructions 3 (17) of the Uniform System of Accounts.
3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

LOCAL ENGINEERING:

Salaries and expenses of Construction and Services Department, Electric Service and Delivery Department, and Gas Department personnel engaged in construction work, but not assignable to a particular work order, are charged to engineering clearing work orders which have been set up in a clearing account for each respective department. Examples of such charges are as follows: work in connection with the construction budget; cost of estimating prior to the issuance of specific work orders; scheduling and assigning construction work; preparation of field reports; conferences on construction matters; general supervision of construction projects, etc.

At the end of each month the costs accumulated in these clearing work orders are allocated to specific work orders coming under the direct supervision of the respective departments. The work orders are spread on the basis of total direct cost of work orders.

The labor and expenses of engineers and foremen who are directly assigned to a particular work order are charged to that work order.

SERVICE CONTRACT CHARGES:

These expenses are charged direct to construction and other projects as applicable based on the service performed.

EMPLOYEE BENEFITS:

Vacation,holiday,sick and other off-duty payments by respondent,together with payments by the Company for hospitalization, dental, group life insurance and pension costs, are charged to construction on the basis of the ratio of direct labor charged to construction, subject to fringe benefits, to the total direct labor, subject to fringe benefits.

ADMINISTRATIVE AND GENERAL EXPENSES:

The allocation of administrative and general expenses to construction is based on a study of the estimated time engaged in construction activities by persons and departments charging time to FERC Account 920. The administrative and general salaries and expenses (FERC Account 920-921) applicable to construction is allocated to all construction work orders on the basis of total direct costs.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION:

The Company does not capitalize an allowance for funds used during construction of gas utility plant.

General Description of Contruction Overhead Procedure (continued)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

For line (5), column (d) below enter the rate granted in the last rate proceeding. If not available, use the average rate earned during the preceding 3 years.

1. Components fo Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	Amount (b)	Capitalization Ration (percent) (c)	Cost Rate Percentage (d)
		S		
				s
		D		d
		P		p
		C		c
		W		

2. Gross Rate for Borrowed Funds s(S/W)+d[(D/(D+P+C))(1-(S/W))]

3. Rate for Other Funds [1-(S/W)][p(P/(D+P+C))+c(C/(D+P+C))]

4. Weighted Average Trate Actually Used for theYear:
   a. Rate for Borrowed Funds -
   b. Rate for Other Funds -

Name of Respondent	This Report Is:	Date of Report	Year of Report
Louisville Gas and Electric Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo,Da,Yr) 03/31/2007	Dec. 31, 2006

ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service, page 204-209, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant In Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
1	Balance Beginning of Year	186,533,978	186,533,978		
2					
3	Depreciation Provisions for Year, Charged to :				
4	(403) Depreciation Expense	14,911,006	14,911,006		
5	(413) Exp. of Gas Plt. Leas. to Others				
6	Transportation Expenses- Clearing	294,103	294,103		
7	Other Clearing Accounts				
8	Other Accounts (Specify):	(55,100)	(55,100)	(2)	
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 4 thru 8)	15,150,009	15,150,009		
10	Net Changes for Plant Retired:				
11	Book Cost of Plant Retired	4,496,633	4,496,633		
12	Cost of Removal	1,732,351	1,732,351		
13	Salvage (Credit)	1,718	1,718		
14	TOTAL Net Chrgs. for Plant Retired (Enter Total of lines 11 thru 13)	6,227,266	6,227,266		
15	Other Debit or Credit Items (Describe):				
16	Customer Payments	444,731	444,731	(1)	
17	Balance End of Year (Enter Total of lines 1, 9, 14, and 16)	195,901,452	195,901,452		

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant In Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
18	Production- Manufactured Gas				
19	Prod. and Gathering - Natural Gas				
20	Products Extraction - Natural Gas				
21	Underground Gas Storage	31,059,044	31,059,044		
22	Underground Gas Storage - ARO	392,040	392,040		
23	Other Storage Plant				
24	Base Load LNG Term. and Proc. Plt.				
25	Transmission	11,615,044	11,615,044		
26	Distribution	146,027,430	146,027,430		
27	Distribution - ARO	19,102	19,102		
28	General	6,788,792	6,788,792		
29	TOTAL (Enter Total of lines 18 thru 26)	195,901,452	195,901,452		

NOTE:
(1) Customer payments related to construction projects.
(2) Accrual for Cost of Removal on ARO Parent Assets impacting (403) and (254) accounts.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr) 03/31/2007	Year of Report Dec. 31, 2006

GAS STORED (ACCOUNT 117, 164.1, 164.2 AND 164.3)

1. If during the year adjustment was made to the stored gas inventory (such as to correct cumulative inaccuracies of gas measurements), furnish in a footnote an explanation of the reason for the adjustment, the Mcf and dollar amount of adjustment, and account charged or credited.
2. Give in a footnote a concise statement of the facts and the accounting performed with respect to any encroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.
3. If the company uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock" and the inventory basis and the accounting performed with respect to any encroachment of withdrawals upon "base stock," or restoration of previous encroachment, including brief particulars of any such accounting during the year.
4. If the company has provided accumulated provision for stored gas which may not eventually be fully recovered from any storage project, furnish a statement showing: (a) date of Commission authorization of such accumulated provision, (b) explanation of circumstances requiring such provision, (c) basis of provision and factors of calculation, (d) estimated ultimate accumulated provision accumulation, and (e) a summary showing balance of accumulated provision and entries during year.
5. Report pressure base of gas volumes as 14.73 psia at 60° F.

Line No.	Description (a)	Noncurrent (Account 117) (b)	Current (Account 164.1) (c)	LNG (Account 164.2) (d)	LNG (Account 164.3) (e)	Total (f)
1	Balance at Beginning of Year	2,139,990	124,868,861			127,008,851
2	Gas Delivered to Storage (contra Account)		82,024,841			82,024,841
3	Gas Withdrawn from Storage (contra Account)		124,055,801			124,055,801
4	Other Debits or Credits (Net)					
5	Balance at End of Year	2,139,990	82,837,901			84,977,891
6	Mcf	2,930,000	11,555,233			14,485,233
7	Amount Per Mcf	73.04¢	716.89¢			586.65¢
8	State basis of segregation of inventory between current and noncurrent portions:					

NOTE:
Line 3, Column C includes $3,056,047 for 358,849 Mcf of gas lost in storage operations; charged to Account 823, Gas Losses.

Louisville Gas and Electric Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr) 03/31/2007	Year of Report Dec. 31, 2006

INVESTMENTS (Accounts 123, 124, 136)

1. Report below investments in Accounts 123, Investments in Associated Companies, 124, Other Investments, and 136, Temporary Cash Investments.
2. Provide a subheading for each account and list thereunder the information called for:
   (a) Investment in Securities - List and describe each security owned, giving name of issuer, date acquired and date of maturity. For bonds, also give principal amount, date of issue, maturity, and interest rate. For capital stock (including capital stock of respondent) reacquired under a definite plan for resale pursuant to authorization by the Board of Directors, and included in Account 124, Other Investments, state number of shares, class, and series of stock. Minor investments may be grouped by classes. Investments included in Account 136, Temporary Cash Investments, also may be grouped by classes.
   (b) Investment Advances - Report separately for each person or company the amounts of loans or investment advances which are properly includable in Account 123. Advances subject to current repayment should be included in Accounts 145 and 146. With respect to each advance, show whether the advance is a note or open

Line No.	Description of Investment (a)	Book Cost at Beginning of Year (If book cost is different from cost to respondent in a footnote and explain difference.) (b)	Purchase or Additions During Year (c)
1	Account 124		
2	Ohio Valley Electric Corporation Common Stock (1)	594,286	-
3			
4		594,286	-
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20	Notes:		
21	(1) Acquired 1952-53.		
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			

Name of Respondent	This Report Is:	Date of Report (Mo,Da,Yr)	Year of Report
Louisville Gas and Electric Company	(1) [x] An Original (2) [ ] A Resubmission	03/31/2007	Dec. 31, 2006

INVESTMENTS (Accounts 123, 124, 136) (Continued)

account. Each note should be listed giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders, or employees. Exclude amounts reported on page 229.

3. For any securities, notes or accounts that were pledged designate with an asterisk such securities, notes, or accounts and in a footnote state the name of pledgee and purpose of the pledge.

4. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.

5. Report in column (g) interest and dividend revenues from investments including such revenues from securities disposed of during the year.

6. In column (h) report for each investment disposed of during the year the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including any dividend or interest adjustment includible in column (g).

Sales or Other Dispositions During Year (d)	Principal Amount or No. of Shares at End of Year (e)	Book Cost at End of Year (If book cost is different from cost to respondent in a footnote and explain difference.) (f)	Revenues for Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
					1
-	5,630 Shs	594,286	231,941	-	2
		-			3
-		594,286	231,941	-	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38