ANNUAL REPORT

OF

CONSUMERS ENERGY COMPANY

TO THE

MICHIGAN PUBLIC SERVICE COMMISSION

FOR THE YEAR ENDED

DECEMBER 31, 2004

MICHIGAN PUBLIC SERVICE COMMISSION

ANNUAL REPORT OF MAJOR AND NONMAJOR ELECTRIC UTILITIES

1909 PA 106, as amended, authorizes this form being MCL 460.551 et seq.; and 1969 PA 306, as amended, being MCL 21.201 et seq. Filing of this form is mandatory. Failure to complete and submit this form will place you in violation of the Acts.

Report submitted for year ending:

December 31, 2004

Present legal name of respondent:

CONSUMERS ENERGY COMPANY

Address of principal place of business:

One Energy Plaza, Jackson, Michigan 49201

Utility representative to whom inquiries regarding this report may be directed:

Name **Thomas J. Webb** Title **Executive Vice President, and Chief Financial Officer**

Address **One Energy Plaza**

City **Jackson** State **Michigan** Zip Code **49201**

Telephone, Including Area Code **(517) 788-0351**

If the utility name has been changed during the past year:

Prior Name

Date of Change

Two copies of the published annual report to stockholders:

[x] were forwarded to the Commission
[ ] will be forwarded to the Commission on or about _____, 20__.

Annual reports to stockholders:

[x] are published. [ ] are not published.

FOR ASSISTANCE IN COMPLETION OF THIS FORM:

Contact the Michigan Public Service Commission at (517) 241-6175 or forward correspondence to:

Commission Operation Division
Market Monitoring & Enforcement Section
6545 Mercantile Way
P.O. Box 30221
Lansing, MI 48909

GENERAL INFORMATION

I. Purpose:

By authority conferred upon the Michigan Public Service Commission by 1909 PA 106, as amended, being MCL 460.556 et seq. and 1969 PA 306, as amended, being MCL 24.201 et seq., this form is a regulatory support requirement. It is designed to collect financial and operational information from public utilities, licensees and others subject to the jurisdiction of the Michigan Public Service Commission. This report is a nonconfidential public use form.

II. Who Must Submit:

Each major and nonmajor pubic utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees must submit this form.

NOTE: Major utilities means utilities that had, in each of the last three consecutive years, sales or transmission service that exceeded any one or more of the following:

(a) one million megawatt-hours of total sales;
(b) 100 megawatt-hours of sales for resale;
(c) 500 megawatt-hours of gross interchange out; or
(d) 500 megawatt-hours of wheeling for others (deliveries plus losses).

III. What and Where to Submit:

(a) Submit an original copy of this form to:

Michigan Public Service Commission
Market Monitoring &Enforcement Section
6545 Mercantile Way
P.O. Box30221
Lansing, MI 48909

Retain one copy of this report for your files.

(b) Submit immediately upon publication, one (1) copy of the latest annual report to stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analyst, or industry association. (Do not include monthly and quarterly reports. If reports to stockholders are not prepared, enter "NA" in column (c) on Page 4, the List of Schedules.) Mail these reports to:

Michigan Public Service Commission
Market Monitoring &Enforcement Section
6545 Mercantile Way
P.O. Box30221
Lansing, MI 48909

(c) For the CPA certification, submit with the original submission, or within 30 days after the filing date for this form, a letter or report:

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

(ii) Signed by independent certified public accountants or an independent licensed public accountant, certified or licensed by a regulatory authority or a state or other political subdivision of the U.S. (See 18 CFR 41.10-41.12 for specific qualifications).

Schedules	Reference Page
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

When accompanying this form, insert the letter or report immediately following the cover sheet. Use the following form for the letter or report unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

> In connection with our regular examination of the financial statements of_____ for the year ended on which we have reported separately under date of_____ we have also reviewed schedules _____ of Form P-521 for the year filed with the Michigan Public Service Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of accounting records and such other auditing procedures as we considered necessary in the circumstances.
>
> Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Michigan Public Service Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

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

(d) Federal, state and local governments and other authorized users may obtain additional blank copies to meet their requirements for a charge from:

Michigan Public Service Commission
Market Monitoring &Enforcement Section
6545 Mercantile Way
P.O. Box30221
Lansing, MI 48909

IV. When to Submit

Submit this report form on or before April 30 of the year following the year covered by this report.

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (USOA). Interpret all accounting words and phrases in accordance with the USOA.

II. Enter in whole number (dollars or MWH) 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 year, and use for statement of income accounts the current year's amounts.

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

IV. For any page(s) that is not applicable to respondent, either

(a) Enter the words "NOT APPLICABLE" on the particular page(s), or

(b) Omit the page(s) and enter "NA", "NONE", or "NOT APPLICABLE" in column (c) on the List of Schedules, pages 2, 3, 4 and 5.

V. Complete this report by means which result in a permanent record. Complete the original copy in permanent black ink or typewriter print, if practical. Additional copies must be clear and readable.

VI. 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 VIII. below). The date of the resubmission must be reported in the header for all form pages, whether or not they are changed from the previous filing.

VII. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ( ).

VIII. When making revisions, resubmit only those pages that have been changed from the original submission. Submit the same number of copies as required for filing the form. Include with the resubmission the identification and Attestation page, page 1. Mail dated resubmissions to:

Michigan Public Service Commission
Market Monitoring &Enforcement Section
6545 Mercantile Way
P.O. Box30221
Lansing, MI 48909

IX. Provide a supplemental statement further explaining accounts or pages as necessary. Attach the supplemental statement (8 1/2 x 11 inch size) to the page being supplemented. Provide the appropriate identification information, including the title(s) of the page and page number supplemented.

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

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

XII. Respondents may submit computer printed schedules (reduced to 8 1/2 x 11 inch size) instead of the preprinted schedules if they are in substantially the same format.

XIII. A copy of the FERC Annual Report Form is acceptable to substitute for the same schedules of this report.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) - The authorization of the Michigan Public Service Commission, or any other Commission. Name the Commission whose authorization was obtained and give the date of the authorization.

II. Respondent - The person, corporation, licensee, agency, authority, or other legal entity or instrumentality in whose behalf the report is made.

MPSC FORM P-521
ANNUAL REPORT OF ELECTRIC UTILITIES, LICENSEES AND OTHERS (Major and Nonmajor)

IDENTIFICATION	
01 Exact Legal Name of Respondent CONSUMERS ENERGY COMPANY	02 Year of Report Dec. 31, 2004
03 Previous Name and Date of Change (If name changed during year)	
04 Address at Principal Business Office at End of Year (Street, City, State, Zip Code) One Energy Plaza Jackson, MI 49201	
05 Name of Contact Person Thomas J. Webb	06 Title of Contact Person Executive Vice President and Chief Financial Officer
07 Address of Contact Person (Street, City, State, Zip Code) One Energy Plaza Jackson, MI 49201	
08 Telephone of Contact Person, Including Area Code (517) 788-0351	09 This Report is (1) [X] An Original (2) [ ] A Resubmission
	10 Date of Report (Mo, Da, Yr)

ATTESTATION

The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 and including December 31 of the year of the report.

01 Name	03 Signature	04 Date Signed (Mo, Da, Yr)
Thomas J. Webb		
02 Title Executive Vice President and Chief Financial Officer	Thomas J. Webb (signed)	

LIST OF SCHEDULES (Electric Utility)

1. Enter in column (c) 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".
2. The "M" prefix below denotes those pages where the information requested by the MPSC differs from that requested by FERC. Each of these pages also contains the "M" designation on the page itself.

Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
GENERAL CORPORATE INFORMATION AND FINANCIAL STATEMENTS		
General Information	101	
Control Over Respondent and Other Associated Companies	102	
Corporations Controlled by Respondent	103	
Officers	M 104	
Directors	M 105	
Security Holders and Voting Powers	M 106-107	
Important Changes During the Year	108-109	
Comparative Balance Sheet	M 110-113	
Statement of Income for the Year	M 114-117	
Statement of Retained Earnings for the Year	118-119	
Statement of Cash Flows	120-121	
Notes to Financial Statements	122-123	
BALANCE SHEET SUPPORTING SCHEDULES (Assets & Other Debits)		
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization, and Depletion	200-201	
Nuclear Fuel Materials	202-203	
Electric Plant in Service	M 204-211	
Electric Plant Leased to Others	213	None
Electric Plant Held for Future Use	214	
Construction Work in Progress - Electric	M 216	
Construction Overheads - Electric	217	
General Description of Construction Overhead Procedure	M 218	
Accumulated Provision for Depreciation of Electric Utility Plant	M 219	
Nonutility Property	M 221	
Investment in Subsidiary Companies	224-225	
Materials and Supply	227	
Allowances	228-229	
Extraordinary Property Losses	230	None
Unrecovered Plant and Regulatory Study Costs	230	
Other Regulatory Assets	M 232	
Miscellaneous Deferred Debits	M 233	
Accumulated Deferred Income Taxes (Account 190)	234	
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)		
Capital Stock	250-251	
Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Received on Capital Stock	252	
Other Paid-in Capital	253	
Discount on Capital Stock	254A	
Capital Stock Expenses	254B	
Long-Term Debt	256-257	

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)		Remarks (c)
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits) (Continued)			
Reconciliation of Reported Net Income With Taxable Income for Federal Income Taxes	M	261	
Taxes Accrued, Prepaid and Charged During Year		262-263	
Distribuiton of Taxes Charged	M	262-263	
Accumulated Deferred Investment Tax Credits	M	266-267	
Other Deferred Credits	M	269	
Accumulated Deferred Income Taxes - Accelerated Amortization Property	M	272-273	None
Accumulated Deferred Income Taxes - Other Property	M	274-275	
Accumulated Deferred Income Taxes - Other		276-277	
Other Regulatory Liabilities	M	278	
INCOME ACCOUNT SUPPORTING SCHEDULES			
Electric Operating Revenues		300-301	
Sales of Electricity by Rate Schedules		304	
Sales for Resale		310-311	
Electric Operation and Maintenance Expenses	M	320-323	
Number of Electric Department Employees		323	
Purchased Power		326-327	
Transmission of Electricity for Others		328-330	None
Transmission of Electricity by Others		332	
Miscellaneous General Expenses - Electric	M	335	
Depreciation and Amortization of Electric Plant	M	336-338	
Particulars Concerning Certain Income Deduction and Interest Charges Accounts		340	
COMMON SECTION			
Regulatory Commission Expenses		350-351	
Research, Development and Demonstration Activities		352-353	None
Distribution of Salaries and Wages		354-355	
Common Utility Plant and Expenses		356	
ELECTRIC PLANT STATISTICAL DATA			
Electric Energy Account		401A	
Monthly Peaks and Output		401B	
Steam-Electric Generating Plant Statistics (Large Plants)		402-403	
Hydroelectric Generating Plant Statistics (Large Plants)		406-407	
Pumped Storage Generating Plant Statistics (Large Plants)		408-409	
Generating Plant Statistics (Small Plants)		410-411	
Transmission Line Statistics		422-423	None
Transmission Lines Added During Year		424-425	None
Substations		426-427	
Electric Distribution Meters and Line Transformers		429	
Environmental Protection Facilities		430	
Environmental Protection Expenses		431	
Footnote Data		450	
Stockholders' Reports		-	

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
MPSC SCHEDULES		
Reconciliation of Deferred Income Tax Expense	117A-B	
Operating Loss Carryforward	117C	
Plant Acquisition Adjustments and Accumulated Provision for Amortization of Plant Acquisition Adjustments	215	None
Investments	222-223	
Notes and Accounts Receivable Summary for Balance Sheet	226A	
Accumulated Provision for Uncollectible Accounts - Credit	226A	
Receivables From Associated Companies	226B	
Miscellaneous Current and Accrued Assets	230A	
Preliminary Survey and Investigation Charges	231A	None
Deferred Losses From Disposition of Utility Plant	235A-B	None
Unamortized Loss and Gain on Reacquired Debt	237A-B	
Securities Issued or Assumed and Securities Refunded or Retired During the Year	255	
Notes Payable	260A	
Payables to Associated Companies	260B	
Miscellaneous Current and Accrued Liabilities	268	
Customer Advances for Construction	268	
Other Deferred Credits	269	
Deferred Gains From Disposition of Utility Plant	270A-B	None
Gain or Loss on Disposition of Property	280A-B	
Income From Utility Plant Leased to Others	281	None
Particulars Concerning Certain Other Income Accounts	282	
Electric Operation and Maintenance Expenses (Nonmajor)	320N-323N	Not Applicable
Number of Electric Department Employees	324N	Not Applicable
Sales to Railroads and Railways and Interdepartmental Sales	331A	
Rent From Electric Property and Interdepartmental Rents	331A	
Sales of Water and Water Power	331B	
Miscellaneous Service Revenues and Other Electric Revenues	331B	
Lease Rentals Charged	333A-D	
Expenditures for Certain Civic, Political and Related Activities	341	
Extraordinary Items	342	
Charges for Outside Professional and Other Consultative Services	357	
Summary of Costs Billed to Associated Companies	358-359	
Summary of Costs Billed from Associated Companies	360-361	
Changes Made or Scheduled To Be Made in Generating Plant Capacities	412	
Steam-Electric Generating Plants	413A-C	
Hydroelectric Generating Plants	414-415	
Pumped Storage Generating Plants	416-418	
Internal-Combustion Engine and Gas Turbine Generating Plants	420-421	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.

Thomas J. Webb, Executive Vice President, and Chief Financial Officer
One Energy Plaza
Jackson, Michigan 49201

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.

Incorporated in Michigan, January 22, 1968

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.

None

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

Electric
Gas

All within the State of Michigan

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
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.

CMS Energy Corporation owns 100% of Consumers Energy Company's outstanding common stock.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	CMS Energy Corporation	Holding company for energy	NA	(A)(B)
2		related businesses		
3	Consumers Energy Company	Energy related utility	NA	
4	Has 12 subsidiaries and 6 trusts:			
5	Consumers Power Company Financing I	Financing-prefd securities	100%	
6	Consumers Energy Company Financing II	Financing-prefd securities	100%	
7	Consumers Energy Company Financing III	Financing-prefd securities	100%	
8	Consumers Energy Company Financing IV	Financing-prefd securities	100%	
9	Consumers Energy Company Financing V	Financing-prefd securities	100%	
10	Consumers Energy Company Financing VI	Financing-prefd securities	100%	
11	CMS Engineering Co	Project engineering mgmt	100%	
12	CMS Midland, Inc	General Partner in the MCV	100%	
13		Partnership		
14	CMS Midland Holdings Company	Leases assets to the MCV	100%	
15		Partnership		
16	Consumers Campus Holdings LLC	Lessee in financing of the	100%	
17		CECo office building		
18	Consumers EnergyGuard Services, Inc.	Dissolved 2/13/04	100%	
19	Consumers Funding, LLC	Assignee of property transfer	100%	
20		and issuer of securiti		
21		zation bonds		
22	Consumers Nuclear Services LLC	To hold 20% member interest	100%	
23		in Nuclear Mgmt LLC		
24	Consumers Receivables Funding LLC	Buy account receivables from	NA	
25		Ceco and sell to third party		
26	Consumers Receivables Funding LLC II	To buy certain account re-	NA	
27		ceivables from Consumers		

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1		and sell to a third party		
2	Consumers Saginaw Investemnts L.L.C.			
3	ES Services Company	Energy related services	100%	
4	MEC Development Corp	Held bonds issued in connec-	100%	
5		tion with MCV Partnership		
6	CMS Enterprises Company	Energy-related projects	NA	(A)(B)
7	Has 9 subsidiaries:	world-wide		
8	CMS Capital LLC	Financial services	NA	(C)
9	CMS Comercializadora de Energia SA (COMESA)	Gas & electric marketing	NA	(B)(C)
10	(99% Owner)	operation in Argentina		
11	CMS Distributed Power, LLC	Aggregating generation	NA	(C)
12	CMS Energy Asia Private Limited		NA	(C)
13	CMS Energy Resource Management Co	Provide marketing and risk/	NA	(C)
14		energy management services		
15	CMS ERM Michigan LLC			
16	CMS Viron Corporation			
17	Dorman Energy, L.L.C			
18	CMS Energy South America Company		NA	(C)
19	CMS Enterprises Development Co S.A.			
20	CMS Energy UK Limited	Energy related projects in	NA	(C)
21		Europe, Africa, Middle East		
22	CMS Enterprises Development, LLC		NA	(C)
23	CMS Enterprises Holdings Company, SA	Argentina holding company	NA	(B)(C)
24	Dearborn Industrial Energy, L.L.C.			
25	Dearborn Industrial Generation, L.L.C.			
26	CMS Generation Co	Development engineering,	NA	(B)(C)
27	Has 36 subsidiaries:	management & operations for		

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	CMS Centrales Termicas S.A.	independent power plants		
2	CMS Generation Altoona Company	Dissolved 07/22/2004		
3	CMS Generation Chateaugay Company	Dissolved 10/21/2004		
4	CMS Generation Filer City Operating Co			
5	CMS Generation Filer City, Inc			
6	CMS Generation Genesee Company			
7	CMS Generation Grayling Company			
8	CMS Generation Grayling Holdings Company			
9	CMS Generation Holdings Company			
10	CMS Generation Honey Lake Company			
11	Honey Lake Energy I L.P.			
12	Honey Lake Energy II L.P.			
13	CMS Generation Investment Company I	Dissolved 12/31/2004		
14	CMS Generation Investment Company VI			
15	CMS Takoradi Investment Company			
16	CMS Generation Investment Company VII			
17	CMS Generation Taweelah Limited			
18	CMS Jubail Investment Company I			
19	CMS Generation Lyonsdale Company	Dissolved 12/21/2004		
20	CMS Generation Michigan Power LLC			
21	CMS Generation Mon Valley Company	Dissolved 7/19/2004		
22	CMS Generation Montreal Company	Dissolved 11/23/2004		
23	CMS Generation Operating Company			
24	CMS Generation Recycling Company			
25	CMS International Operating Company			
26	CMS (India) Operatons and Maintenance Co			
27	Jorf Lasfar Operations Handelsbolag (99%)			

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	CMS Rio Grande do Sul Ltda	Inactive		
2	Dearborn Generation Operating, LLC			
3	Exeter Management Company (50% Owner)			
4	Exeter Energy Limited Partnership			
5	Hydra-Co Enterprises, Inc			
6	McCook Cogeneration Sta. LLC (50% Owner)	Dissolved 11/04/2004		
7	McCook Waste Wood Recovery Fac. LLC (50%)	Dissolved 11/18/2004		
8	Metro East LLC (50% Owner)	Dissolved 10/22/2004		
9	MCV2 Development Company Partnership			
10	Midland Cogeneration Venture Exp LLC			
11	Notera Holding B.V.			
12	Oxford Tire Recycling, Inc			
13	Oxford Tire Supply, Inc			
14	Oxford/CMS Development LP			
15	Scudder Latin American Power I-C LDC (25%)			
16	Servicios de Aguas de Chile CMS y Compania			
17	Taweelah A2 Operating Company			
18	CMS Land Company	Purchase & develop property	NA	(C)
19	Bay Harbor Properties, LLC	Inactive		
20	CMS International Ventures, LLC			(B)(C)
21	CMS Electric & Gas, LLC			
22	CMS Gas Transmission del Sur Company			
23	CMS Generation Investment Company III			
24	CMS Generation Investment Company V			
25	CMS Generation, S.R.L.			
26	CMS Luxembourg S.A.R.L.			
27	CMS Operating S.R.L. (99%)		NA	(B)(C)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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	CMS Ensenada SA (99%)			
2	Cuyana SA de Inversiones (99%)			
3	Transportadora de Gas del Mercosur (20%)			
4	CMS Gas Transmission Company			
5	Has 14 subsidiaries:			
6	Atlantic Methanol Capital Company (50%)			
7	CMS Energy Investment LLC			
8	CMS Antrim Gas Company			
9	CMS Gas Argentina Company			
10	CMS Bay Area Pipeline LLC			
11	CMS Gas Offshore Investment Ltd	Dissolved 12/31/2004		
12	CMS Grands Lacs LLC			
13	CMS Jackson LLC			
14	Jackson Pipeline Company (75%)			
15	CMS Litchfield LLC			
16	CMS Saginaw Bay Lateral Company	Dissolved 11/01/2004		
17	CMS TriState Canada General Company	Dissolved 11/23/2004		
18	Nitrotec Corporation			
19	Otsego EOR LLC			
20	Western Austrailia Gas Transmission I	Sold 08/17/2004		
21	Explotaciones CMS Oil and Gas Company			(C)
22	CMS Resource Development Company	Pursue and develop power	NA	(C)
23		sources outside US		
24	CMS MicroPower Systems LLC	Dissolved 04/01/2004	NA	(C)
25	CMS North American Development LLC	Development in America	NA	(C)
26	CMS Texas LLC	To do business in Texas	NA	(C)
27	CMS Special Member Company			

FOOTNOTE DATA

Schedule Page: 103 Line No.: 1 Column: d

(A) CMS Energy Corporation is the parent holding company of Respondent and CMS Enterprises Company. They may have some common directors and officers.

(B) Under common control

(C) Wholly owned subsidsiary of CMS Enterprises Company

OFFICERS

1. Report below the name, title and salary for the top five executive officers.
2. Report in column (b) salaries and wages accrued during the year including deferred compensation.
3. In column (c) report any other compensation provided, such as bonuses, car allowance, stock options and rights, savings contribution, etc., and explain in a footnote what the amounts represent.
4. If a change was made during the year in the incumbent of any position, show name and total renumeration of the previous incumbent, and the date the change in incumbency occurred.
5. Upon request, the Company will provide the Commission with supplemental information on officers and other employee's salaries.

Line No.	Name and Title (a)		Base Wages (b)	Other Compensation (2) (c)	Total 2004 Compensation (d)	Portion of compensation charged to Consumers Energy
1	KWhipple (1)	Chairman of the Board (3)	937,500	973,100	1,910,600	1,772,389
2	DWJoos (1)	Chief Executive Officer (3)	841,250	672,987	1,514,237	1,175,737
3	SKSmith (1)	Vice Chariman of the Board	650,000	525,667	1,175,667	850,667
4	TJWebb (1)	Executive Vice President and Chief Financial Officer	555,000	400,933	955,933	731,933
5	JGRussell	President and Chief Operating Officer	364,583	252,727	617,310	617,310
6						
7						
8						
9						
10						
11						
12						
13	The above listed officers are those officers that are included in CMS Energy Corporation's					
14	annual Proxy Statement filed with the Securities and Exchange Commission					
15						
16						
17	(1) These employees are also employees of CMS Energy Corp. or its subsidiaries and accordingly					
18	the appropriate portion of their compensation is charged to these companies					
19						
20	(2) Other compensation includes executive incentive compensation, insurance benefits, and other reimbursements					
21						
22	(3) Effective October 1, 2004 Kenneth Whipple was appointed Chairman of the Board and David W. Joos					
23	was appointed Chief Executive Officer					
24						
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DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a) abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Name (and Title) of Director (a)	Principal Business Address (b)	Number of Directors' Meetings Attended During Year (c)	Fees During Year(1) (d)
Merribel S. Ayres (2)	Lighthouse Energy Group, LLC, Washington D.C.	5	28,000
James J. Duderstadt (3)	University of Michigan, Ann Arbor, Michigan	6	43,500
Kathleen R. Flaherty (3)	Round Hill, Virginia	5	42,750
Earl D. Holton***	Grand Rapids, Michigan	10	53,750
David W. Joos (4) Chief Executive Officer	One Energy Plaza, Jackson, Michigan	11	0
Michael T. Monahan	Monahan Enterprises, LLC, Bloomfield Hills, Michigan	11	62,750
Joseph F. Paquette, Jr.	Gladwyne, Pennsylvania	10	64,000
William U. Parfet***	MPI Research, Inc., Mattawan, Michigan	8	63,000
Percy A. Pierre	Michigan State University, East Lansing, Michigan	10	51,750
S. Kinnie Smith, Jr. Vice Chairman of the Board	One Energy Plaza, Jackson, Michigan	11	0
Kenneth L. Way***	Bloomfield Hills, Michigan	9	56,250
Kenneth Whipple** (5) Chairman of the Board and CEO	One Energy Plaza, Jackson, Michigan	11	40,500
John B. Yasinsky***	Pittsburgh, Pennsylvania	10	58,833

(1) Represents fees paid for both CMS Energy Corporation and Consumers Energy Company Board activities. Fees are prorated to each company on the Massachusetts formula.

(2) Elected May 28, 2004.

(3) Retired effective May 28, 2004.

(4) Resigned as President and Chief Operating Officer and elected Chief Executive Officer effective October 1, 2004.

(5) Resigned as Chief Executive Officer effective October 1, 2004.

SECURITY HOLDERS AND VOTING POWERS

1. (A) Give the names and addresses fo the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compliation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.
(B) Give also the name and indicate the voting powers resulting form ownership of securities of the respondent of each officer and director not included in the list of 10 largest security holders.

2. If any security other than stock carries voting rights, explain in a footnote the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent; if contigent, describe the contingency.

3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.

4. Furnish particulars (details) concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten larger security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:

Books not closed prior to end of the year.

2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy:

Total:	84,108,789
By Proxy:	84,108,789

3. Give the date and place of such meeting:

May 28, 2004
Jackson, Michigan

SECURITY HOLDERS AND VOTING POWERS (CONTINUED)

Line No.	Name (Title) and Address of Security Holder (a)	Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
	TOTAL votes of all voting securities	84,550,388	84,108,789	441,599	0
	TOTAL number of security holders	1,932	1	1,931	0
	TOTAL votes of security holders listed below	84,439,554	84,108,789	330,765	0
	1. (A) Largest Security Holders				
	CMS Energy Corporation One Energy Plaza Jackson, MI 49201	84,108,789	84,108,789		
	Cede & Co* Box 222, Bowling Green Station New York, NY 10274	316,613		316,613	
	Jane Pettee TOD Charles M. Pettee & Roger F. Pettee 831 Lakeshore Drive Rice Lake, MI 54868	3,680		3,680	
16 17 18	Mary I. Kohler & Raymond Hetterick Ttee of the Arnold Kohler Trust UA Dtd 6/9/89 2049 Kansas Avenue, NE St Petersburg, FL 33703	2,000		2,000	
	Ralph Zemke and Agnes M. Zemke Joint Tenants PO Box 364 Belmont, MI 49306	2,000		2,000	
19 20 21	Walter M. Jones 215 Rumsey Lansing, MI 48912	1,470		1,470	
	William R. Houghton and Elizabeth P. Houghton, Joint Tenants 310 N. Rolling Oaks San Antonio, TX 78253	1,410		1,410	
33 34 35	Alan L. Johns 1254 Fountain Drive Columbus, OH 43221	1,340		1,340	
	William R. Barnes & Judy K. Barnes TRS UA DTD 9/7/93 9530 Moscow Rd Horton, MI 49246	1,247		1,247	
	Quentin G. Hanson, Jr 6352 FM 2611 Brazoria, TX 77422	1,005		1,005	
44	Total Votes - 10 Largest Stockholders	84,439,554	84,108,789	330,765	
45	* Nominee--Represents various brokers and banks				
46					
47	1. (B) Security Holdings of Officers and Directors				
48	K. Whipple Chairman of the Board	0		0	
49	D W Joos Chief Executive Officer	0		0	
50	S. K. Smith, Jr., Vice Chairman of the Board	10		10	
51	M J Ayres Director	0		0	
52	E D Holton Director	0		0	
53	M. T. Monahan Director	0		0	
54	J. F. Paquette, Jr., Director	0		0	
55	W U Parfet Director	10		10	
56	P A Pierre Director	0		0	
57	K L Way Director	10		10	
58	J B Yasinsky Director	10		10	
59	Total Votes - Officers and Directors	40		40	
60					

RESPONSE TO INSTRUCTION 2
No security, other than stock, carries voting rights.

RESPONSE TO INSTRUCTION 3
No special voting privileges in the election of directors except that whenever four quarterly dividends payable on the Preferred Stock of any class shall be in default in whole or in part, the holders of the Preferred Stock shall have the exclusive right to elect the majority of the Company's directors.

RESPONSE TO INSTRUCTION 4
Not applicable.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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.

1. CHANGES IN AND IMPORTANT ADDITIONS TO FRANCHISE RIGHTS:
There were no significant changes in franchise rights and no important additions thereto. All franchise rights that were acquired or renewed in 2004 were done so without the payment of consideration.

2. AQUISITION OF OWNERSHIP IN OTHER COMPANIES BY REORGANIZATION, MERGER OR CONSOLIDATION WITH OTHER COMPANIES:

None

3. PURCHASE OR SALE OF AN OPERATING UNIT OR SYSTEM:

None

4. IMPORTANT LEASEHOLDS (OTHER THAN LEASHOLDS FROM NATURAL GAS LANDS) THAT HAVE BEEN AQUIRED OR GIVEN, ASSIGNED OR SURRENDERED:

At December 31, 2003, the coal car lease between Consumers Energy and Wells Fargo Bank Northwest, NA expired. All but 210 of the coal cars were returned to the lessor. The remaining cars were purchased by GATX Financial Corporation and leased to Consumers Energy for a two year term, with automatic renewal for successive 24-month terms until written notice is given by either party to terminate the lease. The first payment was due on June 1, 2004. The lease payment for 2004 was $0.7 million and the annual lease payment thereafter is $1.3 million.

In March 2004, Consumers Energy entered into a lease agreement with Babcock & Brown Rail Funding for 451 Coal Cars. The lease term is five years with the first payment due May 1, 2004. The lease payment for 2004 was $1.5 million and the annual lease payment thereafter is $2.2 million.

5. IMPORTANT EXTENTIONS OR REDUCTIONS OF TRANSMISSION OR DISTRIBUTION SYSTEM:

2004 GAS SUPPLY ARRANGEMENTS

Supplier	DTH/D	Term
Anadarko	10,000	02/01/04 - 02/29/04
Anadarko	20,000	04/01/04 - 03/31/05
BP Energy	21,000	04/01/04 - 04/30/04
BP Energy	20,890	05/01/04 - 10/31/04
BP Energy	50,000	05/01/04 - 05/31/04
BP Energy	20,000	08/18/04 - 08/31/04
BP Energy	30,000	04/01/04 - 03/31/05
Chevron/Texaco	30,000	04/01/04 - 03/31/05
Cinergy	50,000	04/01/04 - 12/31/04
Cinergy	32,000	02/01/04 - 02/29/04
Cinergy	34,000	02/01/04 - 02/29/04
ConocoPhillips	32,877	04/01/04 - 03/31/05
Eagle Energy	10,000	04/01/04 - 10/31/04
JAron	22,300	05/01/04 - 10/31/04
Morgan Stanley	25,000	02/01/04 - 02/29/04
Morgan Stanley	30,000	04/01/04 - 03/31/05
Morgan Stanley	5,000	04/01/04 - 03/31/05
Morgan Stanley	9,200	5,7,8,10 & 12/04
Morgan Stanley	8,184	6,9 &11/04
MX Energy	209,881	04/28/04 - 04/28/04
Nexen	20,000	04/01/04 - 03/31/06
Nexen	20,500	04/01/04 - 03/31/05
Noble	50,000	04/01/04 - 03/31/05
Oxy	22,300	04/01/04 - 04/30/04
Sequent	10,000	04/01/04 - 04/30/04

Sequent	10,000	04/01/04 - 04/30/04
Sequent	9,400	05/01/04 - 10/31/04
Tenaska	20,000	04/01/04 - 10/31/04
Tenaska	32,000	04/01/04 - 10/31/04
Tenaska	30,000	11/01/04 - 03/31/05
Tenaska	10,000	11/01/04 - 03/31/05
Tenaska	10,000	11/01/04 - 03/31/05
Tenaska	10,000	11/01/04 - 03/31/05
Total/Fina/Elf	50,000	04/01/04 - 04/30/04
Total/Fina/Elf	50,000	05/01/04 - 05/31/04
Total/Fina/Elf	50,000	06/01/04 - 03/31/05
WPS	80,000	04/01/04 - 04/30/04
WPS	80,000	05/01/04 - 05/31/04
WPS	47,333	06/01/04 - 06/30/04
WPS	57,193	07/01/04 - 07/31/04
WPS	25,000	08/01/04 - 08/31/04
WPS	25,000	09/01/04 - 09/30/03

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:

Consumers' current authorization to issue short-term "securities" (used herein as that term is defined by FERC) was granted by FERC on June 15, 2004 in Docket No. ES04-31-000 and its current authorization to issue long-term securities was granted on June 16, 2004 in Docket No. ES04-32-000. Orders in those dockets authorized Consumers to have outstanding at any one time up to $1.1 billion of short-term securities for general corporate purposes and up to $1.1 billion of First Mortgage Bonds to be issued solely as security for other short-term securities and authorized Consumers to issue up to the following amounts of long-term securities: (1) $1.5 billion for general corporate purposes, (2) $1 billion for refinancing or refunding existing long-term securities, and (3) $2.5 billion to be issued solely as security for other long-term securities. Those authorizations were in effect for all of the fourth quarter of 2004.

A waiver of FERC's competitive bid/negotiated placement requirements was in place for all of the fourth quarter of 2004 for all long-term securities issuances.

Consumers Energy secures its First Mortgage Bonds by a mortgage and lien on substantially all of its property. Consumers' ability to issue and sell securities is restricted by certain provisions in its First Mortgage Bond Indenture, its Articles of Incorporation and the need for regulatory approvals to meet appropriate federal law.

At December 31, 2004 Consumers had a $500 million working capital facility, expiring on August 2, 2005, which it uses to finance its seasonal working capital requirements. As of December 31, 2004, no borrowing was outstanding under the facility, although $24.7 million of letters of credit were outstanding. As of December 31, 2004, Consumers also had a $60 million term loan outstanding at a weighted average interest rate of 2.85 percent. Both facilities were secured by First Mortgage Bonds.

On December 12, 2004, Consumers Energy issued $225 million of 5.0% First Mortgage Bonds with a maturity date of March 15, 2015. Proceeds from the sale of the bonds were used to retire Consumers Energy's 7.375% First Mortgage Bonds of 2023.

In addition to the securities listed above, Consumers Energy has an agreement for an ongoing sale of its accounts receivables in an amount not to exceed $325 million, unless increased by mutual consent. As of December 31, 2004, $304 million of receivables were sold under this agreement.

7. CHANGES IN ARTICLES OF INCORPORATION OR AMENDMENTS TO CHARTER:

None

8. STATE THE ESTIMATED ANNUAL EFFECT AND NATURE OF ANY IMPORTANT WAGE SCALE CHANGES DURING THE YEAR:

Consumers' wage scale adjustments in the last quarter of 2004, were as follows: Total general increase was $662,226 of which $543,025 was chargeable to operations. Total cost-of-living allowances was $219,150 of which $179,703 was chargeable to operations.

9. STATE BRIEFLY THE STATUS OF ANY MATERIALLY IMPORTANT LEGAL PROCEDINGS PENDING AT THE END OF THE YEAR, AND THE RESULTS OF ANY SUCH PROCEEDINGS CULMINATED DURING THE YEAR:

Consumers and some of its subsidiaries and affiliates are parties to certain routine lawsuits and administrative proceedings incidental to their businesses involving, for example, claims for personal injury and property damage, contractual matters, various taxes, and rates and licensing. Reference is made to the Notes to Consolidated Financial Statements, included herein, for additional information regarding various pending administrative and judicial proceedings involving regulatory, operating and environmental matters.

Securities Class Action Lawsuits: Beginning on May 17, 2002, a number of securities class action complaints were filed against CMS Energy, Consumers, and certain officers and directors of CMS Energy and its affiliates. The complaints were filed as purported class actions in the United States District Court for the Eastern District of Michigan, by shareholders who allege that they purchased CMS Energy's securities during a purported class period. These cases were later consolidated by the court. The plaintiffs generally seek unspecified damages based on allegations that the defendants violated United States securities laws and regulations by making allegedly false and misleading statements about CMS Energy's business and financial condition, particularly with respect to revenues and expenses recorded in connection with round trip trading by CMS MST. CMS Energy, Consumers, and the individual defendants filed motions to dismiss on June 21, 2004. The judge issued an opinion and order dated January 7, 2005, granting the motion to dismiss for Consumers and three of the individual defendants, but denying the motions to dismiss for CMS Energy and the 13 remaining individual defendants. CMS Energy and the individual defendants will defend themselves vigorously but cannot predict the outcome of this litigation.

ERISA Lawsuits: CMS Energy is a named defendant, along with Consumers, CMS MST, and certain named and unnamed officers and directors, in two lawsuits brought as purported class actions on behalf of participants and beneficiaries of the CMS Employees' Savings and Incentive Plan (the "Plan"). The two cases were filed in July 2002 in United States District Court for the Eastern District of Michigan and were later consolidated by the court. Plaintiffs allege breaches of fiduciary duties under ERISA and seek restitution on behalf of the Plan with respect to a decline in value of the shares of CMS Energy Common Stock held in the Plan. Plaintiffs also seek other equitable relief and legal fees. The judge issued an opinion and order dated December 27, 2004, conditionally granting plaintiffs' motion for class certification. A trial date has not been set, but is expected to be no earlier than late in 2005. CMS Energy and Consumers will defend themselves vigorously but cannot predict the outcome of this litigation.

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:

See Notes 1, 2, and 3 of Notes to Consolidated Financial Statements.

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Michigan Transmission Holdings, LLP, is a non-affiliated limited partnership whose general partner is a subsidiary of Trans-Elect, Inc. A Trans-Elect, Inc. subsidiary provides interstate electric transmission service to Consumers. The Federal Energy Regulatory Commission approves the rates and other terms of service and they remain subject to the Commission's jurisdiction. Consumers' Vice Chairman and director served as Vice Chairman of Trans-Elect, Inc. from May 15, 2002 until June 30, 2002; he resigned as Vice Chairman and director of Trans-Elect, Inc. upon becoming Vice Chairman and director of Consumers in July of 2002. The Vice Chairman and director currently owns 20,000 shares of Convertible Preferred A Stock of Trans-Elect, Inc., or approximately 10% of the outstanding voting securities of Trans-Elect, Inc. and also has an option to acquire an additional 250 shares of this security.

13. DESCRIBE FULLY ANY CHANGES IN OFFICERS, DIRECTORS, MAJOR SECURITY HOLDERS AND VOTING POWERS OF THE RESPONDENT THAT MAY HAVE OCCURRED DURING THE PERIOD:

Ken Whipple (previously Chairman of the Board and Chief Executive Officer of Consumers Energy Company) appointed Chairman of the Board - October 1, 2004

David W. Joos (previously President and Chief Operating Officer of Consumers Energy Company) appointed Chief Executive Officer - October 1, 2004

John G. Russell (previously Executive Vice President and President-Electric and Gas) appointed President and Chief Operating Officer - October 1, 2004

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, SUBSIDARY, OR AFFILIATED COMPANIES THROUGH A CASH MANAGEMENT PROGRAM(S). ADDITIONALLY, PLEASE DESCRIBE PLANS, IF ANY TO REGAIN AT LEAST A 30 PERCENT PROPRIETARY RATIO.

NA

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account	Ref. Page No.	Balance at Beginning of Yr	Balance at End of Year
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	$10,132,293,560	$10,577,759,885
3	Construction Work in Progress (107)	200-201	374,984,455	340,580,582
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		$10,507,278,015	$10,918,340,467
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	5,085,719,106	5,303,941,597
6	Net Utility Plant (Enter Total of line 4 less 5)		$5,421,558,909	$5,614,398,870
7	Nuclear Fuel (120.1-102.4, 120.0)	202-203	316,081,624	350,143,089
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	325,469,620	340,595,962
9	Net Nuclear Fuel (Enter Total of line 7 less 8)		($9,387,996)	$9,547,127
10	Net Utility Plant (Enter Total of lines 6 and 9)		$5,412,170,913	$5,623,945,997
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored Underground-Noncurrent (117)	220-Gas	0	0
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	221	$15,067,221	$15,007,071
15	(Less) Accum. Prov. for Depr. and Amort. (122)	221	917,308	1,620,352
16	Investments in Associated Companies (123)	222-223	20,113,070	24,669,200
17	Investment in Subsidiary Companies (123.1)	224-225	668,037,531	761,190,933
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
19	Noncurrent Portion of Allowances	228-229	0	0
20	Other Investments (124)	222-223	6,686,897	6,652,188
21	Special Funds (125-128)		597,686,545	605,410,963
22	TOTAL Other Property and Investments (Total of lines 14 thru 17, 19 thru 21)		$1,306,673,956	$1,411,310,003
23	CURRENT AND ACCRUED ASSETS			
24	Cash (131)		$43,336,745	$13,865,089
25	Special Deposits (132-134)		0	5,319,313
26	Working Funds (135)		2,680,151	112,044
27	Temporary Cash Investments (136)	222-223	1,442,238	32,074,158
28	Notes Receivable (141)	226A	0	5,942,160
29	Customer Accounts Receivable (142)	226A	14,158,341	9,529,496
30	Other Accounts Receivable (143)	226A	29,806,056	36,451,751
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	226A	8,451,343	9,909,700
32	Notes Receivable from Associated Companies (145)	226B	0	0
33	Accounts Receivable from Assoc. Companies (146)	226B	4,880,776	14,571,739
34	Fuel Stock (151)	227	41,031,275	48,732,160
35	Fuel Stock Expense Undistributed (152)	227	0	0
36	Residuals (Elec) and Extracted Products (Gas) (153)	227	0	0
37	Plant Material and Operating Supplies (154)	227	70,252,911	66,993,127
38	Merchandise (155)	227	0	0
39	Other Material and Supplies (156)	227	0	0
40	Nuclear Materials Held for Sale (157)	202,227	0	20

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

Line No.	Title of Account	Ref. Page No.	Balance at Beginning of Yr	Balance at End of Year
41	Allowances	228-229	22,269,745	15,594,075
42	(Less) Noncurrent Portion of Allowances		0	0
43	Stores Expenses Undistributed (163)	227	(560,136)	0
44	Gas Stored Underground - Current (164.1)	220-Gas	739,123,655	854,841,552
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	220-Gas	0	0
46	Prepayments (165)		428,695,180	424,148,076
47	Advances for Gas (166-167)		0	0
48	Interest and Dividends Receivable (171)		6,967	16,134
49	Rents Receivable (172)		1,596,471	1,400,688
50	Accrued Utility Revenues (173)		0	117,567
51	Miscellaneous Current and Accrued Assets (174)	229	214,526,039	218,152,130
52	TOTAL Current and Accrued Assets (Enter Total of lines 23 thru 51)		$1,604,795,071	$1,737,951,579
53	DEFERRED DEBITS			
54	Unamortized Debt Expense (181)		$39,597,074	$40,859,776
55	Extraordinary Property Losses (182.1)	230B	0	0
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230B	10,354,377	9,835,861
57	Other Regulatory Assets	232	1,073,523,034	1,643,359,877
58	Prelim. Survey and Investigation Charges (Electric) (183)	231	0	0
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)	231	0	0
60	Clearing Accounts (184)		(6,916,929)	559,640
61	Temporary Facilities (185)		0	0
62	Miscellaneous Deferred Debits (186)	233	30,782,731	42,494,243
63	Def. Losses from Disposition of Utility Plt. (187)	236	0	0
64	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
65	Unamortized Loss on Reacquired Debt (189)	237	51,048,225	71,384,788
66	Accumulated Deferred Income Taxes (190-192)	234-235	758,404,139	809,287,809
67	Unrecovered Purchased Gas Costs (191)		0	0
68	TOTAL Deferred Debits (Enter Total of lines 53 thru 67)		$1,956,792,651	$2,617,781,994
69	TOTAL Assets and other Debits (Enter Total of lines 10, 11, 12, 22, 52, and 68)		$10,280,432,591	$11,390,989,573

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account	Ref. Page No.	Balance at Beginning of Yr	Balance at End of Year
1	PROPRIETARY CAPTIAL			
2	Common Stock Issued (201)	250-251	$841,087,890	$841,087,890
3	Preferred Stock Issued (204)	250-251	44,159,900	44,159,900
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	386,028,613	386,028,613
7	Other Paid-In Capital (208-211)	253	336,732,838	600,860,948
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	23,718,573	23,718,573
11	Retained Earnings (215, 215.1, 216)	118-119	299,689,261	383,259,128
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	220,948,792	224,488,555
13	(Less) Reacquired Capital Stock (217)	250-251	0	0
14	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)		$2,104,928,721	$2,456,166,461
15	LONG-TERM DEBT			
16	Bonds (221)	256-257	$1,482,700,000	$2,300,000,000
17	(Less) Reacquired Bonds (222)	256-257	0	0
18	Advances from Associated Companies (223)	256-257	894,541,239	865,895,379
19	Other Long-Term Debt (224)	256-257	1,679,052,149	1,095,436,983
20	Unamortized Premium on Long-Term Debt (225)		2,982,906	2,656,078
21	(Less) Unamortized Discount on Long-Term Debt-Dr. (226)		24,146,482	18,450,135
22	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)		$4,035,129,812	$4,245,538,305
23	OTHER NONCURRENT LIABILITIES			
24	Obligations Under Capital Leases - Noncurrent (227)		$57,703,424	$47,906,111
25	Accumulated Provision for Property Insurance (228.1)		0	0
26	Accumulated Provision for Injuries and Damages (228.2)		21,467,900	33,382,996
27	Accumulated Provision for Pensions and Benefits (228.3)		190,106,327	560,810,943
28	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
29	Accumulated Provision for Rate Refunds (229)		15,026,070	23,308,031
30	TOTAL Other Noncurrent Liabilities (Total of lines 24 thru 29)		$284,303,721	$665,408,081
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)	260A	$0	$0
33	Accounts Payable (232)		186,049,674	240,279,436
34	Notes Payable to Associated Companies (233)	260B	237,361,641	38,218,389
35	Accounts Payable to Associated Companies (234)	260B	74,543,876	64,125,373
36	Customer Deposits (235)		23,329,595	29,580,152
37	Taxes Accrued (236)	262-263	202,338,954	267,907,444
38	Interest Accrued (237)		54,518,570	55,103,798
39	Dividends Declared (238)		0	0
40	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account	Ref. Page No	Balance at Beginning of Yr	Balance at End of Year
41	Matured Interest (240)		0	0
42	Tax Collections Payable (241)		554,113	3,112,110
43	Miscellaneous Current and Accrued Liabilities (242)	268	124,914,680	106,257,888
44	Obligations Under Capital Leases-Current (243)		10,175,510	10,389,983
45	Fed. Inc. Tax Accrued - Prior Year (244)		0	0
46	Michigan Single Business Taxes Accrued for Prior Years (244.1)		0	0
47	Fed. Inc. Tax Accrued - Prior Year Adj (245)		0	0
48	Michigan Single Business Taxes Accrued for Prior Years-Adj. (245.1)		0	0
49	TOTAL Current and Accrued Liabilities (Total of lines 32 thru 48)		$913,786,613	$814,974,573
50	DEFERRED CREDITS			
51	Customer Advances for Construction (252)	268	$27,442,562	$33,503,806
52	Accumulated Deferred Investment Tax Credits (255)	266-267	73,057,767	69,229,339
53	Deferred Gains from Disposition of Utility Plant (256)	270	0	0
54	Other Deferred Credits (253)	269	505,802,112	577,565,519
55	Other Regulatory Liabilities	278	514,192,326	559,110,940
56	Unamortized Gain on Reacquired Debt (257)	237	0	0
57	Accumulated Deferred Income Taxes (281-284)	272-277	1,821,788,957	1,969,492,549
58	TOTAL Deferred Credits (Enter Total of lines 51 thru 57)		$2,942,283,724	$3,208,902,153
59	TOTAL Liabilities and Other Credits (Enter Total of lines 14, 22, 30, 49 and 58)		$10,280,432,591	$11,390,989,573

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (l, k, m, o) in a similar manner to a utility department. Spread the amount(s) over lines 02 thru 24 as appropriate. Include thses amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.
4. Use pages 122-123 for important notes regarding the statement of income or any account therof.
5. Give concise explanations concerning unsettled rate proceedings where a contigency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenue or costs to which the contigency 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

Line No.	Account	Ref. Page No.	TOTAL Current Year	TOTAL Previous Year
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	$4,632,102,099	$4,380,900,514
3	Operating Expenses			
4	Operation Expenses (401)	320-323	$3,309,484,576	$3,065,541,648
5	Maintenance Expenses (402)	320-323	$207,914,744	191,944,340
6	Depreciation Expense (403)	336-337	$285,083,864	316,200,884
7	Amort. & Depl. of Utility Plant (404-405)*	336-337	$18,960,791	18,588,748
8	Amort. of Utility Plant Acq. Adj. (406)	336-337	$6,158	6,158
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)		$518,516	612,648
10	Amort. of Conversion Expenses (407)		$0	0
11	Regulatory Debits		$53,917,936	41,709,000
12	(Less) Regulatory Credits		$56,673,000	0
13	Taxes Other Than Income Taxes (408.1)	262-263	$192,730,731	180,642,257
14	Income Taxes - Federal (409.1)	262-263	(13,242,647)	(69,085,400)
15	- Other (409.1)	262-263	0	(402,839)
16	Provision for Deferred Inc. Taxes (410.1)	234,272-276	$318,269,093	402,223,442
17	(Less) Provision for Deferred Income Taxes - Cr.(411.1)	234,272-276	$178,530,658	197,807,849
18	Investment Tax Credit Adj. - Net (411.4)	266-267	(3,828,428)	(4,114,717)
19	(Less) Gains from Disp. of Utility Plant (411.7)	270A-B	$29,583	0
20	Losses from Disp. of Utility Plant (411.7)	235A-B	$172,591	0
21	(Less) Gains from Disposition of Allowances			9,549,027
22	Losses from Disposition of Allowances		$20,764	0
23	TOTAL Utility Operating Expenses (Total of lines 4 thru 22)		$4,134,775,448	$3,936,509,293
24	Net Utility Operating Income (Enter total of line 2 less 23) (Carry forward to page 117, line 25)		$497,326,651	$444,391,221

* Current year amount includes $549,030, last year includes $1,267,095 of ARO accretion expense.

STATEMENT OF INCOME FOR THE YEAR (CONTINUED)

amounts paid with respect to power and gas purchases.

6. 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 purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such as notes may be included on pages 122-123.

8. Enter on pages 122-123 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 approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior years.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on pages 122-123 or in a footnote.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year	No.
						1
$2,542,779,074	$2,543,909,804	$2,089,323,025	$1,836,990,710	$0	$0	2
						3
$1,604,259,577	$1,576,524,671	$1,705,224,999	$1,489,016,977	$0	$0	4
165,494,317	151,907,048	42,420,427	40,037,292	0	0	5
182,859,584	197,309,806	102,224,280	118,891,078	0	0	6
8,829,569	9,242,802	10,131,222	9,345,946	0	0	7
0	0	6,158	6,158	0	0	8
						9
518,516	555,801	0	56,847	0	0	
0	0	0	0	0	0	10
53,861,090	41,709,000	56,847	0	0	0	11
56,673,000	0	0	0	0	0	12
139,164,730	130,999,557	53,566,001	49,642,700	0	0	13
(20,432,643)	(25,889,074)	7,189,996	(43,196,326)	0	0	14
0	(293,879)	0	(108,960)	0	0	15
224,447,615	265,199,058	93,821,478	137,024,384	0	0	16
117,679,248	142,101,872	60,851,410	55,705,977	0	0	17
(2,964,770)	(3,032,223)	(863,658)	(1,082,494)	0	0	18
29,583	0	0	0			19
166,606	0	5,985	0			20
0	9,549,027		0			21
20,764	0		0			22
$2,181,843,123	$2,192,581,668	$1,952,932,325	$1,743,927,625	$0	$0	23
$360,935,951	$351,328,136	$136,390,700	$93,063,085	$0	$0	24

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STATEMENT OF INCOME FOR THE YEAR (Continued)				
Line No.	Account	Ref. Page No.	TOTAL Current Year	TOTAL Previous Year
25	Net Utility Operating Income (Carried forward from page 114)		$497,326,651	$444,391,221
26	Other Income and Deductions			
27	Other Income			
28	Nonutility Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)	282	$44,803,444	$47,514,704
30	(Less) Costs & Exp. of Merchandising,Job & Contr. Work (416)	282	36,761,677	41,326,173
31	Revenues From Nonutility Operations (417)	282	1,854,296	5,542,723
32	(Less)Expenses of Nonutility Operations (417.1)	282	1,708,413	1,826,153
33	Nonoperating Rental Income (418)	282	497,946	638,895
34	Equity in Earnings of Subsidiary Companies (418.1)	119,282	2,128,290	19,999,799
35	Interest and Dividend Income (419)	282	5,723,645	6,755,013
36	Allowance for Other Funds Used During Construction (419.1)	282	(143,197)	3,034,218
37	Miscellaneous Nonoperating Income (421)	282	126,662,061	15,684,658
38	Gain on Disposition of Property (421.1)	280	1,554,447	2,791,010
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		$144,610,842	$58,808,694
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)	280	$793,696	$1,196,123
42	Miscellaneous Amortization (425)	340	0	0
43	Miscellaneous Income Deductions (426.1-426.5)	340,341	37,206,265	75,340,876
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		$37,999,961	$76,536,999
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	$370,568	$787,320
47	Income Taxes - Federal (409.2)	262-263	27,336,288	(19,071,645)
48	Income Taxes - Other (409.2)	262-263	0	
49	Provision for Deferred Inc. Taxes (410.2)	234,272-276	13,476,850	12,427,085
50	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234,272-276	12,626,755	8,099,558
51	Investment Tax Credit Adj.- Net (411.5)	264-265	0	0
52	(Less) Investment Tax Credits (420)	264-265	0	0
53	TOTAL Taxes on Other Inc. & Ded. (Total of lines 46 thru 52)		$28,556,951	($13,956,798)
54	Net Other Income and Deductions (Total of lines 39, 44, & 53)		$78,053,930	($3,771,507)
55	Interest Charges			
56	Interest on Long-Term Debt (427)	257	$196,096,207	$154,634,127
57	Amortization of Debt Disc. and Expense (428)	256-257	8,884,323	18,643,930
58	Amortization of Loss on Reacquired Debt (428.1)		8,032,964	1,617,841
59	(Less) Amort. of Premium on Debt - Credit (429)	256-257	326,828	678,213
60	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)		0	0
61	Interest on Debt to Assoc. Companies (430)	257-340	68,229,491	66,623,601
62	Other Interest Expense (431)	340	10,474,488	12,523,728
63	(Less)Allow. for Borrowed Funds Used During Constr.-Cr. (432)		(4,916,369)	8,711,477
64	Net Interest Charges (Total of lines 56 thru 63)		$296,307,014	$244,653,537
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		$279,073,567	$195,966,177
66	Extraordinary Items			
67	Extraordinary Income (434)	342	$0	$0
68	(Less) Extraordinary Deductions (435)	342	0	0
69	Net Extraordinary Items (Enter Total of line 67 less line 68)		$0	$0
70	Income Taxes - Federal and Other (409.3)	262-263	0	0
71	Extraordinary Items After Taxes (Total of line 69 less line 70)		$0	$0
72	Net Income (Enter Total of lines 65 and 71)		$279,073,567	$195,966,177

RECONCILIATION OF DEFERRED INCOME TAX EXPENSE

1. Report on this page the charges to accounts 410, 411 and 420 reported in the contra accounts 190, 281, 282, 283 and 284.
2. The charges to the subaccounts of 410 and 411 found on pages 114-117 should agree with the subaccount totals reported on this page. In the event the deferred income tax expenses reported on pages 114-117 do not directly reconcile with the amounts found on this page, then provide the additional information requested in instruction #3, on a separate page.

Line No.		Electric Utility	Gas Utility
1	Debits to Account 410 from:		
2			
3	Account 190	29,979,669	17,950,975
4	Account 281	0	0
5	Account 282	74,521,885	33,562,236
6	Account 283	119,946,061	42,308,267
7	Account 284	0	0
8			
9	Reconciling Adjustments	0	0
10	Total Account 410.1 (on pages 114-15 line 16)	224,447,615	93,821,478
11	Total Account 410.2 (on page 117 line 49)		
12			
13			
14	Credits to Account 411 from:		
15			
16	Account 190	35,658,597	34,337,525
17	Account 281	0	
18	Account 282	30,669,814	12,023,386
19	Account 283	51,350,837	14,490,499
20	Account 284	0	0
21	Reconciling Adjustments	0	0
22	Total Account 411.1 (on pages 114-15 line 17)	117,679,248	60,851,410
23	Total Account 411.2 (on page 117 line 50)		
24			
25	Net ITC Adjustment - Account 255		
26	ITC Utilized for the Year DR	0	0
27	ITC Amortized for the Year CR	(2,964,770)	(863,658)
28	ITC Adjustments:		
29	Adjust last year's estimate		
30	to actual per filed return	0	0
31			
32	Other (specify)	0	0
33	Net Reconciling Adjustments Account 411.4*	(2,964,770)	(863,658)
34	Net Reconciling Adjustments Account 411.5**		
35	Net Reconciling Adjustments Account 420***		

* on pages 114-115 line 18
** on page 117 line 51
*** on page 117 line 52

RECONCILIATION OF DEFERRED INCOME TAX EXPENSE (Continued)

3. (a) Provide a detailed reconciliation of the applicable deferred income tax expense subaccount(s) reported on pages 114-117 with the amount reported on this page.
(b) Identify all contra accounts (other than accounts 190 and 281-284).
(c) Identify the company's regulatory authority to utilize a contra account other than accounts 190 or 281-284 for the recording of deferred income tax expense(s).

Other Utility	Total Utility	Other Income	Total Company	Line No.
				1
				2
0	47,930,644	12,474,426	60,405,070	3
0	0	0	0	4
0	108,084,121	4,594	108,088,715	5
0	162,254,328	997,830	163,252,158	6
0	0	0	0	7
				8
0	0	0	0	9
0	318,269,093			10
		13,476,850		11
				12
				13
				14
				15
0	69,996,122	11,689,422	81,685,544	16
0	0	0	0	17
0	42,693,200	5,709	42,698,909	18
0	65,841,336	931,624	66,772,960	19
0	0	0	0	20
0	0	0	0	21
0	178,530,658			22
		12,626,755		23
				24
				25
0	0	0	0	26
0	(3,828,428)	0	(3,828,428)	27
				28
				29
0	0	0	0	30
				31
0	0	0	0	32
0	(3,828,428)	0		33
		0		34
		0		35

OPERATING LOSS CARRYFORWARD

Fill in below when the company sustains an operating loss, loss carryback or carryforward whenever or wherever applicable.

Line No.	Year (a)	Operating Loss (b)	Loss or Carryforward (F) or Carryback (B) (c)	Loss Utilized		Balance Remaining (f)
				Amount (d)	Year (e)	
1	2001	674,397,536	F	634,387,239	various	40,010,297
2	2003	142,656,967	F	130,791,795	various	11,865,172
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
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18						
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21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35	Total					51,875,469

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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		154,183,046	102,038,144
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)		276,945,277	175,966,378
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess Hydro Earnings		-3,416,411	(4,167,831)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-3,416,411	(4,167,831)
23	Dividends Declared-Preferred Stock (Account 437)			
24	4.50 Preferred		-1,679,180	(1,679,180)
25	4.16 Preferred		-284,756	(284,756)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,963,936	(1,963,936)
30	Dividends Declared-Common Stock (Account 438)			
31			-190,000,000	(218,115,783)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-190,000,000	(218,115,783)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		1,411,474	100,426,074
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		237,159,450	154,183,046

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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)
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39			100,000,000	100,000,000
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		100,000,000	100,000,000
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		47,511,152	44,094,741
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		147,511,152	144,094,741
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		384,670,602	298,277,787
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		222,360,266	302,786,541
50	Equity in Earnings for Year (Credit) (Account 418.1)		2,128,290	19,999,799
51	(Less) Dividends Received (Debit)		1,411,475	30,450,000
52	Dissolved Subsidiaries - transferred to 216 (MGS, METCO, PARNALL HLDS)			(69,976,074)
53	Balance-End of Year (Total lines 49 thru 52)		223,077,081	222,360,266

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	279,073,567	195,966,177
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	301,265,236	375,850,343
5	Amortization of Capital Lease and Debt	25,765,240	28,223,851
6	Gain on Disposition of Property	-760,751	-1,594,887
7	Regulatory Return on Capital Expenditures	-112,935,000	
8	Deferred Income Taxes (Net)	86,032,939	192,544,906
9	Investment Tax Credit Adjustment (Net)	-3,828,428	-4,114,717
10	Net (Increase) Decrease in Receivables	-104,973,302	-30,622,953
11	Net (Increase) Decrease in Inventory	-128,719,154	-255,273,074
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	118,246,938	-68,365,239
14	Net (Increase) Decrease in Other Regulatory Assets	-12,873,447	-36,298,930
15	Net Increase (Decrease) in Other Regulatory Liabilities	44,974,480	56,060,009
16	(Less) Allowance for Other Funds Used During Construction	-143,197	3,034,218
17	(Less) Undistributed Earnings from Subsidiary Companies	716,816	-24,868,201
18	Bad Debt Expense	20,260,237	20,748,682
19	Cumulative Effect of Change in Accounting	739,887	
20	Prepayments	4,547,104	-385,592,858
21	Change in Other Assets and Liabilities	22,040,386	-86,862,200
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	538,282,313	22,503,093
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-429,747,385	-375,753,234
27	Gross Additions to Nuclear Fuel	-34,587,697	-24,160,227
28	Gross Additions to Common Utility Plant	-23,109,542	-84,244,375
29	Gross Additions to Nonutility Plant	-2,339	
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)	-487,446,963	-484,157,836
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	1,939,430	2,454,458
38	Cost to Retire Property	-73,250,302	-71,919,431
39	Investments in and Advances to Assoc. and Subsidiary Companies	-41,380,079	-34,622,413
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Miscellaneous Investments	15,667,253	20,507,345
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
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/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			
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			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-584,470,661	-567,737,877
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,038,767,087	1,602,644,617
62	Preferred Stock		
63	Common Stock		
64	Contribution from Stockholder	250,000,000	
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,288,767,087	1,602,644,617
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-837,158,417	-760,520,000
74	Preferred Stock		
75	Common Stock		
76	Payment of Capital Leases	-9,918,822	-13,453,981
77			
78	Net Decrease in Short-Term Debt (c)	-199,143,252	-256,040,144
79			
80	Dividends on Preferred Stock	-2,446,778	-1,972,078
81	Dividends on Common Stock	-190,000,000	-218,115,783
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	50,099,818	352,542,631
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	3,911,470	-192,692,153
87			
88	Cash and Cash Equivalents at Beginning of Period	47,459,134	240,151,287
89			
90	Cash and Cash Equivalents at End of period	51,370,604	47,459,134

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

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, providing a subheading for each statement except where a note is applicable to more than one statement.
2. 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 Commmission 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.

Consumers Energy Company
Notes to Consolidated Financial Statements

The footnotes included herein are from Consumers Energy's annual report as of December 31, 2004, which are prepared on a consolidated basis as permitted by instruction 6 on page 122 of this report. These include the consolidated balances of the Midland Cogeneration Venture Limited Partnership and First Midland Limited Partnership (FMLP) as of December 31, 2004, in accordance with Revised FASB Interpretation 46. The financial statements on pages 110-121 of this report are prepared utilizing the equity method of accounting for the subsidiaries of Consumers Energy and reflect the line item classifications utilized in regulatory accounting. Accordingly, the footnotes have been presented on a consolidated basis as allowed by regulatory guidance. The FMLP's earnings for 2004 was $33 million. Summarized financial information of the MCV Partnership for 2004 follows:

Statements of Income

	In Millions
Years Ended December 31	2004
Operating revenue	$650
Operating expenses	574
Operating income	76
Other expense, net	99
Net Income	(23)

Balance Sheet

			In Millions
December 31	2004		2004
Assets		**Liabilities and Equity**	
Current assets	$ 367	Current liabilities	$ 226
Plant, net	1,425	Non-current liabilities	944
Other assets	188	Partners' equity	810
	$ 1,980		$ 1,980

1: Corporate Structure and Accounting Policies

Corporate Structure: Consumers, a subsidiary of CMS Energy, a holding company, is a combination electric and gas utility company that provides service to customers in Michigan's Lower Peninsula. Our customer base includes a mix of residential, commercial, and diversified industrial customers, the largest segment of which is the automotive industry.

Principles of Consolidation: The consolidated financial statements include Consumers, and all other entities in which we have a controlling financial interest or are the primary beneficiary, in accordance with Revised FASB Interpretation No. 46. The primary beneficiary of a variable interest entity is the party that absorbs or receives a majority of the entity's expected losses or expected residual returns or both as a result of holding variable interests, which are ownership, contractual, or other economic interests. In 2004, we consolidated the MCV Partnership and the FMLP in accordance with Revised FASB Interpretation No. 46. For additional details, see Note 13, Implementation of New Accounting Standards. These entities are reported as equity method investments in our consolidated financial statements for all periods prior to January 1, 2004. We use the equity method of accounting for investments in companies and partnerships that are not consolidated, where we have significant influence over operations and financial policies, but are not the primary beneficiary. Intercompany transactions and balances have been eliminated.

Use of Estimates: We prepare our consolidated financial statements in conformity with U.S. generally accepted accounting principles. We are required to make estimates using assumptions that may affect the reported amounts and disclosures. Actual results could differ from those estimates.

We are required to record estimated liabilities in the consolidated financial statements when it is probable that a loss will be incurred in the future as a result of a current event, and when the amount can be reasonably estimated. We have used this accounting principle to record estimated liabilities as discussed in Note 2, Contingencies.

Revenue Recognition Policy: We recognize revenues from deliveries of electricity and natural gas, and the storage of natural gas when services are provided. Sales taxes are recorded as liabilities and are not included in revenues.

Capitalized Interest: We are required to capitalize interest on certain qualifying assets that are undergoing activities to prepare them for their intended use. Capitalization of interest for the period is limited to the actual interest cost that is incurred. Our regulated businesses are permitted to capitalize an allowance for funds used during construction on regulated construction projects and to include such amounts in plant in service.

Cash Equivalents and Restricted Cash: All highly liquid investments with an original maturity of three months or less are considered cash equivalents.

At December 31, 2004, our restricted cash on hand was $21 million. Restricted cash dedicated for repayment of Securitization bonds is classified as a current asset as the payments on the related Securitization bonds occur within one year.

Financial Instruments: We account for investments in debt and equity securities using SFAS No. 115. Debt and equity securities classified as available-for-sale are reported at fair value determined from quoted market prices. Debt and equity securities classified as held-to-maturity are reported at cost. Unrealized gains or losses resulting from changes in fair value of certain available-for-sale debt and equity securities are reported, net of tax, in equity as part of accumulated other comprehensive income. Unrealized gains or losses are excluded from earnings unless the related changes in fair value are determined to be other than temporary.

Unrealized gains or losses on our nuclear decommissioning investments are reflected as regulatory liabilities on our Consolidated Balance Sheets. Realized gains or losses would not affect our earnings or cash flows.

For additional details regarding financial instruments, see Note 4, Financial and Derivative Instruments.

Gas Inventory: We use the weighted average cost method for valuing working gas and recoverable cushion gas in underground storage facilities

Generating Plant Fuel Stock Inventory: We use the weighted average cost method for valuing coal inventory and classify these costs as generating plant fuel stock on our Consolidated Balance Sheets. The MCV Partnership's natural gas inventory is also included in this category, stated at the lower of cost or market and valued using the last-in, first-out ("LIFO") method.

Impairment of Investments and Long-Lived Assets: We evaluate the potential impairment of our investments in projects and other long-lived assets, other than goodwill, based on various analyses, including the projection of undiscounted cash flows, whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. If the carrying amount of the investment or asset exceeds its estimated undiscounted future cash flows, an impairment loss is recognized, and the investment or asset is written down to its estimated fair value.

Maintenance and Depreciation: We charge property repairs and minor property replacements to maintenance expense. We also charge planned major maintenance activities to operating expense unless the cost represents the acquisition of additional components or the replacement of an existing component. We capitalize the cost of plant additions and replacements. We depreciate utility property using straight-line rates approved by the MPSC. The composite depreciation rates for our properties are:

Years Ended December 31	2004	2003	2002
Electric utility property	3.2%	3.1%	3.1%
Gas utility property	3.7%	4.6%	4.5%
Other property	8.4%	8.1%	7.2%

Nuclear Fuel Cost: We amortize nuclear fuel cost to fuel expense based on the quantity of heat produced for electric generation. For nuclear fuel used after April 6, 1983, we charge certain disposal costs to nuclear fuel expense, recover these costs through electric rates, and remit them to the DOE quarterly. We elected to defer payment for disposal of spent nuclear fuel burned before April 7, 1983. As of December 31, 2004, we have recorded a liability to the DOE of $141 million, including interest, which is payable upon the first delivery of spent nuclear fuel to the DOE. The amount of this liability, excluding a portion of interest, was recovered through electric rates. For additional details on disposal of spent nuclear fuel, see Note 2, Contingencies, "Other Electric Contingencies – Nuclear Matters."

Other Income and Other Expense: The following tables show the components of Other income and Other expense:

			In Millions
Years Ended December 31	2004	2003	2002
Other income			
Electric restructuring return	$ 6	$ 8	$ 4
Return on stranded costs	7	-	-
Return on security costs	2	-	-
All other	1	2	2
Total other income	$ 16	$ 10	$ 6

			In Millions
Years Ended December 31	2004	2003	2002
Other expense			
Loss on SERP investment	$ (1)	$ (1)	$ (3)

Loss on CMS Energy stock	-	(12)	(12)
Civic and political expenditures	(2)	(2)	(3)
Donations	(1)	-	-
All other	(3)	(4)	(7)
Total other expense	$ (7)	$ (19)	$ (25)

Property, Plant, and Equipment: We record property, plant, and equipment at original cost when placed into service. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost is charged to accumulated depreciation. The cost of removal, less salvage, is recorded as a regulatory liability. For additional details, see Note 6, Asset Retirement Obligations. An allowance for funds used during construction is capitalized on regulated construction projects. With respect to the retirement or disposal of non-regulated assets, the resulting gains or losses are recognized in income.

Property, plant, and equipment at December 31, 2004 and 2003, was as follows:

In Millions

Years Ended December 31		Estimated Depreciable Life in Years (e)	2004	2003
Electric:				
	Generation	13-105	$ 3,433	$ 3,332
	Distribution	12-75	4,069	3,799
	Other	7-50	384	388
	Capital leases (a)		81	81
Gas:				
	Underground storage facilities (b)	30-65	255	232
	Transmission	15-75	367	342
	Distribution	40-75	2,057	1,976
	Other	7-50	290	300
	Capital leases (a)		26	25
Other:	MCV Facility	5-35	2,481	-
	Non-utility property	7-71	15	15
	Construction work-in-progress		353	375
	Other		27	-
Less accumulated depreciation, depletion, and amortization (c)			5,665	4,417
Net property, plant, and equipment (d)			$ 8,173	$ 6,448

(a) Capital leases presented in this table are gross amounts. Accumulated amortization of capital leases was $49 million at December 31, 2004 and $38 million at December 31, 2003.

(b) Includes unrecoverable base natural gas in underground storage of $26 million at December 31, 2004 and $23 million

at December 31, 2003, which is not subject to depreciation.

(c) As of December 31, 2004, accumulated depreciation, depletion, and amortization is comprised of $4.601 billion from public utility plant, $1.063 billion related to the consolidation of the MCV Facility, and $1 million from our non-utility plant assets. As of December 31, 2003, accumulated depreciation, depletion, and amortization included $4.416 billion from our public utility plant and $1 million related to non-utility plant assets.

(d) Included in net property, plant and equipment are intangible assets primarily related to software development costs, consents, leasehold improvements, and rights of way. The estimated amortization life for software development costs is seven years. The estimated amortization life for leasehold improvements is over the life of the lease. Other intangible amortization lives range from 50 to 105 years. Intangible assets at December 31, 2004 and 2003 were as follows:

			In Millions
Year Ended December 31, 2004	Gross Cost	Accumulated Amortization	Intangible Asset, Net
Software development	$ 179	$ 117	$ 62
Rights of way	93	28	65
Leasehold improvements	20	13	7
Franchises and consents	19	9	10
Other intangibles	18	14	4
Totals	$ 329	$ 181	$ 148

			In Millions
Year Ended December 31, 2003	Gross Cost	Accumulated Amortization	Intangible Asset, Net
Software development	$ 178	$ 107	$ 71
Rights of way	89	25	64
Leasehold improvements	32	30	2
Franchises and consents	19	8	11
Other intangibles	18	14	4
Totals	$ 336	$ 184	$ 152

Pre-tax amortization expense related to these intangible assets was $19 million for the year ended December 31, 2004, $19 million for the year ended December 31, 2003, and $17 million for the year ended December 31, 2002. Intangible assets amortization is forecasted to range from $8 million to $19 million per year over the next five years.

(e) The following table illustrates the depreciable life for electric and gas structures and improvements:

Electric	Estimated Depreciable Life in Years	Gas	Estimated Depreciable Life in Years
Generation:		Underground storage facilities	45-50
Coal	39-43	Transmission	60
Nuclear	17-25	Distribution	50
Hydroelectric	55-71	Other	50

Other	32
Distribution	50-60
Other	40-42

Reclassifications: Certain prior year amounts have been reclassified for comparative purposes. These reclassifications did not affect consolidated net income for the years presented.

Related Party Transactions: We received income from related parties as follows:

		In Millions		
Type of Income	Related Party	2004	2003	2002
Gas sales, storage, transportation and other services (a)	MCV Partnership	$ -	$ 17	$ 27
Income from our investments in related party trusts (b)	Consumers' affiliated Trust Preferred Securities companies	1	2	-
Dividend income (b)	CMS Energy parent company	-	-	3

We recorded expense from related parties as follows:

		In Millions		
Type of Cost	Related Party	2004	2003	2002
Electric generating capacity and energy (a)	MCV Partnership	$ -	$455	$497
Electric generating capacity and energy	Affiliates of Enterprises	67	64	67
Interest expense on long-term debt (b)	Consumers' affiliated Trust Preferred Securities companies	44	45	-
Gas purchases	CMS ERM	1	27	127
Overhead expense (c)	CMS Energy parent company	-	8	18
Gas transportation (d)	Panhandle/Trunkline	-	1	22
Gas transportation	CMS Bay Area Pipeline, L.L.C.	4	4	4

(a) In 2004, we consolidated the MCV Partnership and the FMLP into our consolidated financial statements in accordance with Revised FASB Interpretation No. 46. For additional details, see Note 13, Implementation of New Accounting Standards.

(b) We issued Trust Preferred Securities through several Consumers' affiliated companies. As of December 31, 2003, we deconsolidated the trusts that hold the mandatorily redeemable Trust Preferred Securities. As a result of the deconsolidation, we now record on the Consolidated Statements of Income, Interest on Long-term debt – related parties to the trusts holding the Trust Preferred Securities. For additional information on Consumers' affiliated Trust Preferred Securities companies, see Note 13, Implementation of New Accounting Standards.

(c) We base our related party transactions on regulated prices, market prices, or competitive bidding.
In 2003, we paid overhead costs to CMS Energy based on an industry allocation methodology, such as the Massachusetts Formula. In 2004, we paid no overhead costs to CMS Energy.

(d) Panhandle was sold in June 2003.

We own 2.4 million shares of CMS Energy Common Stock with a fair value of $25 million at December 31, 2004. For additional details on our investment in CMS Energy Common Stock, see Note 4, Financial and Derivative Instruments.

Trade Receivables: We record our accounts receivable at fair value. Accounts deemed uncollectible are charged to operating expense.

Unamortized Debt Premium, Discount, and Expense: We capitalize premiums, discounts, and expenses incurred in connection with the issuance of long-term debt and amortize those costs ratably over the terms of the debt issues. Any refinancing costs are charged to expenses as incurred. For the regulated portions of our businesses, if we refinance debt, we capitalize any remaining unamortized premiums, discounts, and expenses and amortize them ratably over the terms of the newly issued debt.

Utility Regulation: We account for the effects of regulation based on the regulated utility accounting standard SFAS No. 71. As a result, the actions of regulators affect when we recognize revenues, expenses, assets, and liabilities.

We reflect the following regulatory assets and liabilities, which include both current and non-current amounts, on our Consolidated Balance Sheets. We expect to recover these costs through rates over periods of up to 14 years. We recognized an OPEB transition obligation in accordance with SFAS No. 106 and established a regulatory asset for the amount that we expect to recover in rates over the next eight years.

	In Millions	
December 31	2004	2003
Securitized costs (Note 3)	$ 604	$ 648
Postretirement benefits (Note 5)	530	181
Electric Restructuring Implementation Plan (Note 2)	88	91
Manufactured gas plant sites (Note 2)	65	67
Abandoned Midland project	10	10
Unamortized debt costs	71	51
Asset retirement obligation (Note 6)	83	49
Stranded costs (Note 2)	63	-
Section 10d(4) regulatory asset (Note 2)	141	-
Other	41	8
Total regulatory assets (a)	$ 1,696	$ 1,105
Cost of removal (Note 6)	$ 1,044	$ 983
Income taxes (Note 7)	357	312
Asset retirement obligation (Note 6)	168	168
Other	5	4
Total regulatory liabilities (a)	$ 1,574	$ 1,467

(a) At December 31, 2004, we classified $19 million of regulatory assets as current regulatory assets and we classified

$1.677 billion of regulatory assets as non-current regulatory assets. At December 31, 2003, we classified $19 million of regulatory assets as current regulatory assets and we classified $1.086 billion of regulatory assets as non-current regulatory assets. At December 31, 2004 and December 31, 2003, all of our regulatory liabilities represented non-current regulatory liabilities.

2: Contingencies

SEC and Other Investigations: As a result of round-trip trading transactions by CMS MST, CMS Energy's Board of Directors established a Special Committee to investigate matters surrounding the transactions and retained outside counsel to assist in the investigation. The Special Committee completed its investigation and reported its findings to the Board of Directors in October 2002. The Special Committee concluded, based on an extensive investigation, that the round-trip trades were undertaken to raise CMS MST's profile as an energy marketer with the goal of enhancing its ability to promote its services to new customers. The Special Committee found no effort to manipulate the price of CMS Energy Common Stock or affect energy prices. The Special Committee also made recommendations designed to prevent any recurrence of this practice. Previously, CMS Energy terminated its speculative trading business and revised its risk management policy. The Board of Directors adopted, and CMS Energy implemented the recommendations of the Special Committee.

CMS Energy is cooperating with an investigation by the DOJ concerning round-trip trading. CMS Energy is unable to predict the outcome of this matter and what effect, if any, this investigation will have on its business. In March 2004, the SEC approved a cease-and-desist order settling an administrative action against CMS Energy related to round-trip trading. The order did not assess a fine and CMS Energy neither admitted nor denied the order's findings. The settlement resolved the SEC investigation involving CMS Energy and CMS MST.

Securities Class Action Lawsuits: Beginning on May 17, 2002, a number of securities class action complaints were filed against CMS Energy, Consumers, and certain officers and directors of CMS Energy and its affiliates. The complaints were filed as purported class actions in the United States District Court for the Eastern District of Michigan, by shareholders who allege that they purchased CMS Energy's securities during a purported class period. These cases were later consolidated by the court. The plaintiffs generally seek unspecified damages based on allegations that the defendants violated United States securities laws and regulations by making allegedly false and misleading statements about CMS Energy's business and financial condition, particularly with respect to revenues and expenses recorded in connection with round trip trading by CMS MST. CMS Energy, Consumers, and the individual defendants filed motions to dismiss on June 21, 2004. The judge issued an opinion and order dated January 7, 2005, granting the motion to dismiss for Consumers and three of the individual defendants, but denying the motions to dismiss for CMS Energy and the 13 remaining individual defendants. CMS Energy and the individual defendants will defend themselves vigorously but cannot predict the outcome of this litigation.

ERISA Lawsuits: CMS Energy is a named defendant, along with Consumers, CMS MST, and certain named and unnamed officers and directors, in two lawsuits brought as purported class actions on behalf of participants and beneficiaries of the CMS Employees' Savings and Incentive Plan (the "Plan"). The two cases were filed in July 2002 in United States District Court for the Eastern District of Michigan and were later consolidated by the court. Plaintiffs allege breaches of fiduciary duties under ERISA and seek restitution on behalf of the Plan with respect to a decline in value of the shares of CMS Energy Common Stock held in the Plan. Plaintiffs also seek other equitable relief and legal fees. The judge issued an opinion and order dated December 27, 2004, conditionally granting plaintiffs' motion for class certification. A trial date has not been set, but is expected to be no earlier than late in 2005. CMS Energy and Consumers will defend themselves vigorously but cannot predict the outcome of this litigation.

ELECTRIC CONTINGENCIES

Electric Environmental Matters: Our operations are subject to environmental laws and regulations. Costs to operate our facilities in compliance with these laws and regulations generally have been recovered in customer rates.

Clean Air: The EPA and the state regulations require us to make significant capital expenditures estimated to be $802 million. As of December 31, 2004, we have incurred $525 million in capital expenditures to comply with the EPA regulations and anticipate that the remaining $277 million of capital expenditures will be made between 2005 and 2011.

The EPA has alleged that some utilities have incorrectly classified plant modifications as "routine maintenance" rather than seek modification permits from the EPA. We have received and responded to information requests from the EPA on this subject. We believe that we have properly interpreted the requirements of "routine maintenance." If our interpretation is found to be incorrect, we may be required to install additional pollution controls at some or all of our coal-fired electric plants and potentially pay fines. Additionally, the viability of certain plants remaining in operation could be called into question.

In addition to modifying the coal-fired electric plants, we expect to utilize nitrogen oxide emissions allowances for years 2005 through 2009, most of which have been purchased. The cost of the allowances is estimated to average $8 million per year for 2005-2006. The need for allowances will decrease after year 2006 with the installation of emissions control technology.

Cleanup and Solid Waste: Under the Michigan Natural Resources and Environmental Protection Act, we expect that we will ultimately incur investigation and remedial action costs at a number of sites. We believe that these costs will be recoverable in rates under current ratemaking policies.

We are a potentially responsible party at several contaminated sites administered under Superfund. Superfund liability is joint and several, meaning that many other creditworthy parties with substantial assets are potentially responsible with respect to the individual sites. Based on past experience, we estimate that our share of the total liability for the known Superfund sites will be between $1 million and $9 million. As of December 31, 2004, we have recorded a liability for the minimum amount of our estimated Superfund liability.

In October 1998, during routine maintenance activities, we identified PCB as a component in certain paint, grout, and sealant materials at the Ludington Pumped Storage facility. We removed and replaced part of the PCB material. We have proposed a plan to deal with the remaining materials and are awaiting a response from the EPA.

Litigation: In October 2003, a group of eight PURPA qualifying facilities selling power to us filed a lawsuit in Ingham County Circuit Court. The lawsuit alleges that we incorrectly calculated the energy charge payments made pursuant to power purchase agreements with qualifying facilities. In February 2004, the Ingham County Circuit Court judge deferred to the primary jurisdiction of the MPSC, dismissing the circuit court case without prejudice. In February 2005, the MPSC issued an order in the 2004 PSCR plan case concluding that we have been correctly administering the energy charge calculation methodology. The eight plaintiff qualifying facilities have appealed the dismissal of the circuit court case to the Michigan Court of Appeals. We cannot predict the outcome of this appeal.

ELECTRIC RESTRUCTURING MATTERS

Electric ROA: The MPSC approved revised tariffs that establish the rates, terms, and conditions under which retail customers are permitted to choose an electric supplier. These revised tariffs allow ROA customers, upon as little as 30 days notice to us, to return to our generation service at current tariff rates. If any class of customers' (residential, commercial, or industrial) ROA load reaches ten percent of our total load for that class of customers, then returning ROA customers for that class must give 60 days notice to return to our generation service at current tariff rates. However, we may not have capacity available to serve returning ROA customers that is sufficient or reasonably priced. As a result, we may be forced to purchase electricity on the spot market at higher prices than we can recover from our customers during the rate cap periods. We cannot predict the total amount of electric supply load that may be lost to alternative electric suppliers. As of March 2005, alternative electric suppliers are providing 900 MW of generation supply to ROA customers. This amount represents 12 percent of our distribution load and an increase of 23 percent compared to March 2004.

Electric Restructuring Proceedings: Below is a discussion of our electric restructuring proceedings.

The following chart summarizes our electric restructuring filings with the MPSC:

Proceeding	Year(s) Filed	Years Covered	Requested Amount	Status
Stranded Costs	2002-2004	2000-2003	$137 million (a)	The MPSC ruled that we experienced zero Stranded Costs for 2000 through 2001. The MPSC approved recovery of $63 million in Stranded Costs for 2002 through 2003.
Implementation Costs	1999-2004	1997-2003	$91 million (b)	The MPSC allowed $68 million for the years 1997-2001, plus $20 million for the cost of money through 2003. Implementation cost filings for 2002 and 2003 in the amount of $8 million, which includes the cost of money through 2003, are pending MPSC approval.
Section 10d(4) Regulatory Assets	2004	2000-2005	$628 million	Filed with the MPSC in October 2004.

(a) Amount includes the cost of money through the year in which we expected to receive recovery from the MPSC and assumes recovery of Clean Air Act costs through the Section 10d(4) Regulatory Asset case.

(b) Amount includes the cost of money through the year prior to the year filed.

Section 10d(4) Regulatory Assets: Section 10d(4) of the Customer Choice Act allows us to recover certain regulatory assets through deferred recovery of annual capital expenditures in excess of depreciation levels and certain other expenses incurred prior to and throughout the rate freeze and rate cap periods, including the cost of money. The section also allows deferred recovery of expenses incurred during the rate freeze and rate cap periods that result from changes in taxes, laws, or other state or federal governmental actions. In October 2004, we filed an application with the MPSC seeking recovery of $628 million of Section 10d(4) Regulatory Assets for the period June 2000 through December 2005 consisting of:

- capital expenditures in excess of depreciation,
- Clean Air Act costs,
- other expenses related to changes in law or governmental action incurred during the rate freeze and rate cap periods, and
- the associated cost of money through the period of collection.

Of the $628 million, $152 million relates to the cost of money.

As allowed by the Customer Choice Act, in January 2004, we began accruing and deferring for recovery the 2004 portion of our Section 10d(4) Regulatory Assets. In November 2004, the MPSC issued an order in Detroit Edison's general electric rate case which concluded that Detroit Edison's return of and on Clean Air Act costs incurred from June 2000 through December 2003 are recoverable under Section 10d(4). Based on the precedent set by this order, we recorded an additional regulatory asset in November 2004 for our return of and on Clean Air Act expenditures incurred from 2000 through 2003. Unless we receive an order from the MPSC to the contrary, we will continue to record additional accruals. However, certain aspects of Detroit Edison's electric rate case are different from our Section 10d(4) Regulatory Asset filing. In March 2005, the MPSC Staff filed testimony recommending the MPSC approve recovery of approximately $323 million. We cannot predict the amount, if any, the MPSC will approve as recoverable. At December 31, 2004, total Section 10d(4) Regulatory Assets totaled $141 million.

Transmission Sale: In May 2002, we sold our electric transmission system to MTH, a non-affiliated limited partnership whose general partner is a subsidiary of Trans-Elect, Inc. We are in arbitration with MTH regarding property tax items used in establishing the selling price of our electric transmission system. An unfavorable outcome could result in a reduction of sale proceeds previously recognized of approximately $2 million to $3 million.

ELECTRIC RATE MATTERS

Electric Rate Case: In December 2004, we filed an application with the MPSC to increase our retail electric base rates. The electric rate case filing requests an annual increase in revenues of approximately $320 million. The primary reasons for the request are increased system maintenance and improvement costs, Clean Air Act related expenditures, and employee pension costs. A final order from the MPSC on our electric rate case is expected in late 2005. If approved as requested, the rate increase would go into effect in January 2006 and would apply to all retail electric customers. We cannot predict the amount or timing of the rate increase, if any, which the MPSC will approve.

Power Supply Costs: To reduce the risk of high electric prices during peak demand periods and to achieve our reserve margin target, we employ a strategy of purchasing electric capacity and energy contracts for the physical delivery of electricity primarily in the summer months and to a lesser degree in the winter months. We have purchased capacity and energy contracts partially covering the estimated reserve margin requirements for 2005 through 2007. As a result, we have recognized an asset of $12 million for unexpired capacity and energy contracts as of December 31, 2004. The total premium costs of electric capacity and energy contracts for 2004 were approximately $12 million.

PSCR: The PSCR process assures recovery of all reasonable and prudent power supply costs actually incurred by us. In September 2004, we submitted our 2005 PSCR filing to the MPSC. The proposed PSCR charge would allow us to recover a portion of our increased power supply costs from commercial and industrial customers and, subject to the overall rate caps, from other customers. We self-implemented the proposed 2005 PSCR charge in January 2005. We estimate the increased recovery of power supply costs from commercial and industrial customers to be approximately $49 million in 2005. The revenues from the PSCR charges are subject to reconciliation at the end of the year after actual costs have been reviewed for reasonableness and prudence. We cannot predict the outcome of these PSCR proceedings.

OTHER ELECTRIC CONTINGENCIES

The Midland Cogeneration Venture: The MCV Partnership, which leases and operates the MCV Facility, contracted to sell electricity to Consumers for a 35-year period beginning in 1990 and to supply electricity and steam to Dow. We hold a 49 percent partnership interest in the MCV Partnership, and a 35 percent lessor interest in the MCV Facility.

In 2004, we consolidated the MCV Partnership and the FMLP into our consolidated financial statements in accordance with Revised FASB Interpretation No. 46. For additional details, see Note 13, Implementation of New Accounting Standards. Our consolidated retained earnings include undistributed earnings from the MCV Partnership of $237 million at December 31, 2004 and $245 million at December 31, 2003.

The cost that we incur under the MCV Partnership PPA exceeds the recovery amount allowed by the MPSC. We expense all cash underrecoveries directly to income. We estimate cash underrecoveries of capacity and fixed energy payments as follows:

	2005	2006	2007
Estimated cash underrecoveries	$56	$55	$39

After September 15, 2007, we expect to claim relief under the regulatory out provision in the PPA, limiting our capacity and fixed energy payments to the MCV Partnership to the amount collected from our customers. The MCV Partnership has indicated that it may take issue with our exercise of the regulatory out clause after September 15, 2007. We believe that the clause is valid and fully effective, but cannot assure that it will prevail in the event of a dispute. The MPSC's future actions on the capacity and fixed energy payments recoverable from customers subsequent to September 2007 may affect negatively the earnings of the MCV Partnership and the value of our investment in the MCV Partnership.

Further, under the PPA, variable energy payments to the MCV Partnership are based on the cost of coal burned at our coal plants and our operation and maintenance expenses. However, the MCV Partnership's costs of producing electricity are tied to the cost of natural gas. Because natural gas prices have increased substantially in recent years and the price the MCV Partnership can charge us for energy has not, the MCV Partnership's financial performance has been impacted negatively. Even with the approved RCP, if gas prices continue at present levels or increase, the economics of operating the MCV Facility may be adverse enough to require us to recognize an impairment.

In January 2005, the MPSC issued an order approving the RCP, with modifications. The RCP allows us to recover the same amount of capacity and fixed energy charges from customers as approved in prior MPSC orders. However, we are able to dispatch the MCV Facility on the basis of natural gas market prices, which will reduce the MCV Facility's annual production of electricity and, as a result, reduce the MCV Facility's consumption of natural gas by an estimated 30 to 40 bcf annually. This decrease in the quantity of high-priced natural gas consumed by the MCV Facility will benefit our ownership interest in the MCV Partnership.

The substantial MCV Facility fuel cost savings will be used first to offset fully the cost of replacement power. Second, $5 million annually will be used to fund a renewable energy program. Remaining savings will be split between the MCV Partnership and Consumers. Consumers' direct savings will be shared 50 percent with its customers in 2005 and 70 percent in 2006 and beyond. Consumers' direct savings from the RCP, after a portion is allocated to customers, will be used to offset our capacity and fixed energy underrecoveries expense. Since the MPSC has excluded these underrecoveries from the rate making process, we anticipate that our savings from the RCP will not affect our return on equity used in our base rate filings.

In January 2005, Consumers and the MCV Partnership's general partners accepted the terms of the order and implemented the RCP. The underlying agreement for the RCP between Consumers and the MCV Partnership extends through the term of the PPA. However, either party may terminate that agreement under certain conditions. In February 2005, a group of intervenors in the RCP case filed an application for rehearing of the MPSC order. The Attorney General also filed a claim of appeal with the Michigan Court of Appeals. We cannot predict the outcome of these appeals.

MCV Partnership Property Taxes: In January 2004, the Michigan Tax Tribunal issued its decision in the MCV Partnership's tax appeal against the City of Midland for tax years 1997 through 2000. The MCV Partnership estimates that the decision will result in a refund to the MCV Partnership of approximately $35 million in taxes plus $10 million of interest. The Michigan Tax Tribunal decision has been appealed to the Michigan Court of Appeals by the City of Midland and the MCV Partnership has filed a cross-appeal at the Michigan Court of Appeals. The MCV Partnership also has a pending case with the Michigan Tax Tribunal for tax years 2001 through 2004. The MCV Partnership cannot predict the outcome of these proceedings; therefore, the above refund (net of approximately $16 million of deferred expenses) has not been recognized in 2004 earnings.

Nuclear Plant Decommissioning: Decommissioning funding practices approved by the MPSC require us to file a report on the adequacy of funds for decommissioning at three-year intervals. We prepared and filed updated cost estimates for Big Rock and Palisades on March 31, 2004. Excluding additional costs for spent nuclear fuel storage, due to the DOE's failure to accept this spent nuclear fuel on schedule, these reports show a decommissioning cost of $361 million for Big Rock and $868 million for Palisades. Since Big Rock is currently in the process of being decommissioned, the estimated cost includes historical expenditures in nominal dollars and future costs in 2003 dollars, with all Palisades costs given in 2003 dollars.

In 1999, the MPSC orders for Big Rock and Palisades provided for fully funding the decommissioning trust funds for both sites. In December 2000, funding of the Big Rock trust fund stopped because the MPSC-authorized decommissioning surcharge collection period expired. The MPSC order set the annual decommissioning surcharge for Palisades at $6 million through 2007. Amounts collected from electric retail customers and deposited in trusts, including trust earnings, are credited to a regulatory liability and asset retirement obligation.

Big Rock: Excluding the additional nuclear fuel storage costs due to the DOE's failure to accept this spent fuel on schedule, we are currently projecting that the level of funds provided by the trust for Big Rock will fall short of the amount needed to complete the decommissioning by $26 million. At this time, we plan to provide the additional amounts needed from our corporate funds and, subsequent to the completion of radiological decommissioning work, seek recovery of such expenditures at the MPSC. We cannot predict how the MPSC will rule on our request. The following table shows our Big Rock decommissioning activities:

	In Millions	
	Year-to-Date December 31, 2004	Cumulative Total-to-Date
Decommissioning expenditures (a)	$35	$298

Withdrawals from trust funds	36	279

(a) Includes site restoration expenditures.

These activities had no material impact on net income. At December 31, 2004, we have an investment in nuclear decommissioning trust funds of $52 million for Big Rock. In addition, at December 31, 2004, we have charged $8 million to our FERC jurisdictional depreciation reserve for the decommissioning of Big Rock.

Palisades: Excluding additional nuclear fuel storage costs due to the DOE's failure to accept this spent fuel on schedule, we concluded that the existing surcharge for Palisades needed to be increased to $25 million annually, beginning January 1, 2006, and continue through 2011, our current license expiration date. In June 2004, we filed an application with the MPSC seeking approval to increase the surcharge for recovery of decommissioning costs related to Palisades beginning in 2006. In September 2004, we announced that we will seek a 20-year license renewal for Palisades. In January 2005, we filed a settlement agreement with the MPSC that was agreed to by four of the six parties. The settlement agreement provides for the continuation of the existing $6 million annual decommissioning surcharge through 2011 and for the next periodic review to be filed in March 2007. We are seeking MPSC approval of the settlement, under a contested settlement proceeding, but cannot predict the outcome.

At December 31, 2004, we have an investment in the MPSC nuclear decommissioning trust funds of $513 million for Palisades. In addition, at December 31, 2004, we have a FERC decommissioning trust fund with a balance of $10 million. For additional details on decommissioning costs accounted for as asset retirement obligations, see Note 6, Asset Retirement Obligations.

Nuclear Matters: *DOE Litigation:* In 1997, a U.S. Court of Appeals decision confirmed that the DOE was to begin accepting deliveries of spent nuclear fuel for disposal by January 1998. Subsequent U.S. Court of Appeals litigation, in which we and other utilities participated, has not been successful in producing more specific relief for the DOE's failure to accept the spent nuclear fuel.

There are two court decisions that support the right of utilities to pursue damage claims in the United States Court of Claims against the DOE for failure to take delivery of spent nuclear fuel. Over 60 utilities have initiated litigation in the United States Court of Claims; we filed our complaint in December 2002. In July 2004, the DOE filed an amended answer and motion to dismiss the complaint. In October 2004, we filed a response to the DOE's motion and our motion for summary judgment on liability. Oral argument has been held, and the motions are now before the Court for a decision. If our litigation against the DOE is successful, we anticipate future recoveries from the DOE. We plan to use recoveries to pay the cost of spent nuclear fuel storage until the DOE takes possession as required by law. We can make no assurance that the litigation against the DOE will be successful.

In July 2002, Congress approved and the President signed a bill designating the site at Yucca Mountain, Nevada, for the development of a repository for the disposal of high-level radioactive waste and spent nuclear fuel. We expect that the DOE will submit an application to the NRC sometime in 2005 for a license to begin construction of the repository. The application and review process is estimated to take several years.

Insurance: We maintain nuclear insurance coverage on our nuclear plants. At Palisades, we maintain nuclear property insurance from NEIL totaling $2.750 billion and insurance that would partially cover the cost of replacement power during certain prolonged accidental outages. Because NEIL is a mutual insurance company, we could be subject to assessments of up to $27 million in any policy year if insured losses in excess of NEIL's maximum policyholders surplus occur at our, or any other member's, nuclear facility. NEIL's policies include coverage for acts of terrorism.

At Palisades, we maintain nuclear liability insurance for third-party bodily injury and off-site property damage resulting from a nuclear hazard for up to approximately $10.761 billion, the maximum insurance liability limits established by the Price-Anderson Act. The United States Congress enacted the Price-Anderson Act to provide financial liability protection for those parties who may be liable for a nuclear accident or incident. Part of the Price-Anderson Act's financial protection is a mandatory industry-wide program under which owners of nuclear generating facilities could be assessed if a nuclear incident occurs at any nuclear generating facility. The maximum assessment against us could be $101 million per occurrence, limited to maximum annual installment payments of $10 million.

We also maintain insurance under a program that covers tort claims for bodily injury to nuclear workers caused by nuclear hazards. The policy contains a $300 million nuclear industry aggregate limit. Under a previous insurance program providing coverage for claims brought by nuclear workers, we remain responsible for a maximum assessment of up to $6 million.

Big Rock remains insured for nuclear liability by a combination of insurance and a NRC indemnity totaling $544 million, and a nuclear property insurance policy from NEIL.

Insurance policy terms, limits, and conditions are subject to change during the year as we renew our policies.

GAS CONTINGENCIES

Gas Environmental Matters: We expect to incur investigation and remedial costs at a number of sites under the Michigan Natural Resources and Environmental Protection Act, a Michigan statute that covers environmental activities including remediation. These sites include 23 former manufactured gas plant facilities. We operated the facilities on these sites for some part of their operating lives. For some of these sites, we have no current ownership or may own only a portion of the original site. We have completed initial investigations at the 23 sites. We will continue to implement remediation plans for sites where we have received MDEQ remediation plan approval. We will also work toward resolving environmental issues at sites as studies are completed.

We have estimated our costs for investigation and remedial action at all 23 sites using the Gas Research Institute-Manufactured Gas Plant Probabilistic Cost Model. We expect our remaining costs to be between $37 million and $90 million. The range reflects multiple alternatives with various assumptions for resolving the environmental issues at each site. We base the estimates on discounted 2003 costs using a discount rate of three percent. The discount rate represents a 10-year average of U.S. Treasury bond rates reduced for increases in the consumer price index. We expect to fund most of these costs through insurance proceeds and MPSC-approved rates. As of December 31, 2004, we have recorded a liability of $38 million, net of $44 million of expenditures incurred to date, and a regulatory asset of $65 million. Any significant change in assumptions, such as an increase in the number of sites, different remediation techniques, nature and extent of contamination, and legal and regulatory requirements, could affect our estimate of remedial action costs.

In its November 2002 gas distribution rate order, the MPSC authorized us to continue to recover approximately $1 million of manufactured gas plant facilities environmental clean-up costs annually. This amount will continue to be offset by $2 million to reflect amounts recovered from all other sources. We defer and amortize, over a period of 10 years, manufactured gas plant facilities environmental clean-up costs above the amount currently included in rates. Additional amortization of the expense in our rates cannot begin until after a prudency review in a gas rate case.

GAS RATE MATTERS

Gas Cost Recovery: The GCR process is designed to allow us to recover all of our purchased natural gas costs if incurred under reasonable and prudent policies and practices. The MPSC reviews these costs for prudency in an annual reconciliation proceeding.

The following table summarizes our GCR reconciliation filings with the MPSC. Additional details related to these proceedings follow the table.

Gas Cost Recovery Reconciliation

GCR Year	Date Filed	Order Date	Net Over Recovery	Status
2001-2002	June 2002	May 2004	$3 million	$2 million has been refunded, $1 million is included in our 2003-2004 GCR reconciliation filing
2002-2003	June 2003	March 2004	$5 million	Net over-recovery includes interest accrued through March 2003, and an $11 million disallowance settlement agreement
2003-2004	June 2004	February 2005	$31 million	Filing includes the $1 million and the $5 million GCR net over-recovery above

Net over-recovery amounts included in the table above include refunds that we received from our suppliers which are required to be refunded to our customers.

GCR year 2003-2004: In February 2005, the MPSC approved a settlement agreement that resulted in a credit to our GCR customers for a $28 million over-recovery, plus $3 million interest, using a roll-in refund methodology. The roll-in methodology incorporates a GCR over/under-recovery in the next GCR plan year.

GCR plan for year 2004-2005: In December 2003, we filed an application with the MPSC seeking approval of a GCR plan for the 12-month period of April 2004 through March 2005. In June 2004, the MPSC issued a final Order in our GCR plan approving a settlement. The settlement included a quarterly mechanism for setting a GCR ceiling price. The current ceiling price is $6.57 per mcf. Actual gas costs and revenues will be subject to an annual reconciliation proceeding.

GCR plan for year 2005-2006: In December 2004, we filed an application with the MPSC seeking approval of a GCR plan for the 12-month period of April 2005 through March 2006. Our request proposes using a GCR factor consisting of:

- a base GCR factor of $6.98 per mcf, plus

a quarterly GCR ceiling price adjustment contingent upon future events.

The GCR factor can be adjusted monthly, provided it remains at or below the current ceiling price. The quarterly adjustment mechanism allows an increase in the GCR ceiling price to reflect a portion of cost increases if the average NYMEX price for a specified period is greater than that used in calculating the base GCR factor. Actual gas costs and revenues will be subject to an annual reconciliation proceeding.

2003 Gas Rate Case: In March 2003, we filed an application with the MPSC for a gas rate increase in the annual

amount of $156 million. In December 2003, the MPSC granted an interim rate increase in the amount of $19 million annually. The MPSC also ordered an annual $34 million reduction in our annual depreciation expense and related taxes.

On October 14, 2004, the MPSC issued its Opinion and Order on final rate relief. In the order, the MPSC authorized us to place into effect surcharges that would increase annual gas revenues by $58 million. Further, the MPSC rescinded the $19 million annual interim rate increase. The final rate relief was contingent upon our agreement to:

- achieve a common equity level of at least $2.3 billion by year-end 2005 and propose a plan to improve the common equity level thereafter until our target capital structure is reached,
- make certain safety-related operation and maintenance, pension, retiree health-care, employee health-care, and storage working capital expenditures for which the surcharge is granted,
- refund surcharge revenues when our rate of return on common equity exceeds its authorized 11.4 percent rate,
- prepare and file annual reports that address certain issues identified in the order, and
- file a general rate case on or before the date that the surcharge expires (which is two years after the surcharge goes into effect).

On October 15, 2004, we agreed to these commitments.

2001 Gas Depreciation Case: In December 2003, we filed an update to our gas utility plant depreciation case originally filed in June 2001. On December 18, 2003, the MPSC ordered an annual $34 million reduction in our depreciation expense and related taxes in an interim rate order issued in our 2003 gas rate case.

In October and December 2004, the MPSC issued Opinions and Orders in our gas depreciation case. The October 2004 order requires us to file an application for new depreciation accrual rates for our natural gas utility plant on, or no earlier than three months prior to, the date we file our next natural gas general rate case. The MPSC also directed us to undertake a study to determine why our removal costs are in excess of those of other regulated Michigan natural gas utilities and file a report with the MPSC Staff on or before December 31, 2005.

In February 2005, we requested a delay in the filing date for the next depreciation case until after the MPSC considers the removal cost study, and after the MPSC issues an order in a pending case relating to asset retirement obligation accounting.

OTHER MATTERS

Collective Bargaining Agreements: Approximately 46 percent of our employees are represented by the Utility Workers of America Union. The Union represents Consumers' operating, maintenance, and construction employees and our call center employees. The collective bargaining agreement with the Union for our operating, maintenance, and construction employees will expire on June 1, 2005 and negotiations for a new agreement is underway currently. The collective bargaining agreement with the Union for our call center employees will expire on August l, 2005.

OTHER CONTINGENCIES

In addition to the matters disclosed within this Note, we are party to certain lawsuits and administrative proceedings before various courts and governmental agencies arising from the ordinary course of business. These lawsuits and proceedings may involve personal injury, property damage, contractual matters, environmental issues, federal and state taxes, rates, licensing, and other matters.

We have accrued estimated losses for certain contingencies discussed within this Note. Resolution of these contingencies

is not expected to have a material adverse impact on our financial position, liquidity, or results of operations.

3: Financings and Capitalization

Long-term debt as of December 31 follows:

In Millions

	Interest Rate (%)	Maturity	2004	2003
			$	$
First mortgage bonds	4.250	2008	250	250
	4.800	2009	200	200
	4.400	2009	150	-
	4.000	2010	250	250
	5.000	2012	300	-
	5.375	2013	375	375
	6.000	2014	200	200
	5.000	2015	225	-
	5.500	2016	350	-
	7.375	2023	-	208
			2,300	1,483
Senior notes	6.000	2005	-	300
	6.500	2005	-	141
	6.250	2006	332	332
	6.375	2008	159	159
	6.875	2018	180	180
	6.500	2028	141	142
			812	1,254
Securitization bonds	5.188 (a)	2005-2015	398	426
FMLP Debt (b):				
Subordinated secured notes	11.750	2005	70	-
Subordinated secured notes	13.250	2006	75	-
Tax-exempt subordinated secured notes	6.875	2009	137	-
Tax-exempt subordinated secured notes	6.750	2009	14	-
			296	-
Nuclear fuel disposal liability		(c)	141	139
Tax-exempt pollution control revenue bonds	Various	2010-2018	126	126
Long-term bank debt (d)	Variable	2006	60	200
Other			1	4
			328	469

Total principal amounts outstanding	4,134	3,632
Current amounts	(118)	(28)
Net unamortized discount	(16)	(21)
	$	$
Total Long-term debt	4,000	3,583

(a) Represents the weighted average interest rate at December 31, 2004 (5.097 percent at December 31, 2003).

(b) We consolidate the FMLP in accordance with Revised FASB Interpretation No. 46. The FMLP debt is essentially project debt secured by certain assets of the MCV Partnership and the FMLP. The debt is non-recourse to other assets of Consumers.

(c) Maturity date uncertain.

(d) Paid off in January 2005.

Financings: The following is a summary of significant long-term debt issuances and retirements during 2004:

	Principal (In millions)	Interest Rate (%)	Issue/Retirement Date	Maturity Date
Debt Issuances				
	$			
FMB	150	4.400	August 2004	August 2009
FMB		5.000	August 2004	February 2012
	300			
FMB		5.500	August 2004	August 2016
	350			
FMB		5.000	December 2004	March 2015
	225			
	$			
Total debt issuances	1,025			
Debt Retirements				
	$			
FMLP debt	115	11.750	July 2004	July 2004
Long-term bank debt		Variable	August 2004	March 2009
	140			
Senior notes		6.500	September 2004	June 2018
	141			
Senior notes		6.000	September 2004	March 2005
	300			
FMB		7.375	December 2004	September 2023
	208			
	$			
Total debt retirements	904			

Issuance costs associated with the issuances of FMBs totaled $7 million and are being amortized ratably over the lives of the related debt. Call premiums associated with the debt retirements totaled $20 million and are being amortized ratably over the lives of the newly issued debt.

Subsequent Financing Activities:

In January 2005, we issued $250 million of 5.15 percent FMBs due 2017. We used the net proceeds of $247 million to pay off our $60 million long-term bank loan, to redeem our $73 million 8.36 percent subordinated deferrable interest notes, and to redeem our $124 million 8.20 percent subordinated deferrable interest notes. The subordinated deferrable interest notes are classified as Long-term debt – related parties on our accompanying Consolidated Balance Sheets.

First Mortgage Bonds: We secure our FMBs by a mortgage and lien on substantially all of our property. Our ability to issue and sell securities is restricted by certain provisions in the first mortgage bond indenture, our articles of incorporation, and the need for regulatory approvals under federal law.

Securitization Bonds: Securitization bonds are collateralized by certain regulatory assets. The bondholders have no recourse to our other assets.. Through our rate structure, we bill customers for securitization surcharges to fund the payment of principal, interest, and other related expenses on the Securitization bonds. Securitization surcharges totaled $50 million annually in 2003 and 2004.

Long-Term Debt – Related Parties: We formed various statutory wholly-owned business trusts for the sole purpose of issuing preferred securities and lending the gross proceeds to ourselves. The sole assets of the trusts consist of the debentures described below. These debentures have terms similar to those of the mandatorily redeemable preferred securities the trusts issued. We determined that we do not hold the controlling financial interest in our trust preferred security structures. Accordingly, those entities were deconsolidated as of December 31, 2003 and are reflected in Long-term debt – related parties. The trust preferred securities were previously included in mezzanine equity.

The following is a summary of Long-term debt – related parties as of December 31:

			In Millions	
Debenture and related party	Interest Rate (%)	Maturity	2004	2003
Subordinated deferrable interest notes, Consumers Power Company Financing I (a)	8.36	2015	$ 73	$ 73
Subordinated deferrable interest notes, Consumers Energy Company Financing II (a)	8.20	2027	124	124
Subordinated debentures, Consumers Energy Company Financing III (b)	9.25	2029	180	180
Subordinated debentures, Consumers Energy Company Financing IV	9.00	2031	129	129
Total principal amounts outstanding			506	506
Current amounts			(180)	-
Total Long-term debt – related parties			$ 326	$ 506

(a) Redeemed in February 2005.
(b) Redeemed in January 2005 with available cash.

In the event of default, holders of the trust preferred securities would be entitled to exercise and enforce the trusts' creditor rights against us, which may include acceleration of the principal amount due on the debentures. We have issued certain guarantees with respect to payments on the preferred securities. These guarantees, when taken together with our obligations under the debentures, related indenture and trust documents, provide full and unconditional guarantees for the

trusts' obligations under the preferred securities.

Debt Maturities: At December 31, 2004, the aggregate annual maturities for long-term debt for the next five years are:

In Millions

	Payments Due				
	2005	2006	2007	2008	2009
Long-term debt	$ 118	$ 478	$ 59	$ 504	$ 443

Regulatory Authorization for Financings: We have FERC authorization to issue or guarantee up to $1.1 billion of short-term securities and up to $1.1 billion of short-term FMBs as collateral for such short-term securities. We have FERC authorization to issue up to $1 billion of long-term securities for refinancing or refunding purposes, $1.5 billion of long-term securities for general corporate purposes, and $2.5 billion of long-term FMBs to be issued solely as collateral for other long-term securities.

Revolving Credit Facilities: The following secured revolving credit facilities with banks are available as of December 31, 2004:

In Millions

Company	Expiration Date	Amount of Facility	Amount Borrowed	Outstanding Letters-of-Credit	Amount Available
Consumers (a)		$ 500	$ -	$ 25	$ 475
The MCV Partnership	August 27, 2005	50	-	2	48

(a) This facility expires in August 2005 and may be extended annually at Consumers' option to July 31, 2007. The interest rate on borrowings under this facility is LIBOR plus 125 basis points. Annual fees for letters-of-credit are 125 basis points on the amount outstanding. A quarterly fee of 22.5 basis points is payable on the average daily unused balance.

Sale of Accounts Receivable: Under a revolving accounts receivable sales program, we currently sell certain accounts receivable to a wholly owned, consolidated, bankruptcy remote special purpose entity. In turn, the special purpose entity may sell an undivided interest in up to $325 million of the receivables. We sold $304 million of receivables at December 31, 2004 and we sold $297 million of receivables at December 31, 2003. These sold amounts are excluded from accounts receivable on our Consolidated Balance Sheets. We continue to service the receivables sold to the special purpose entity. The purchaser of the receivables has no recourse against our other assets for failure of a debtor to pay when due and the purchaser has no right to any receivables not sold. No gain or loss has been recorded on the receivables sold and we retain no interest in the receivables sold.

Certain cash flows under our accounts receivable sales program are shown in the following table:

In Millions

Years Ended December 31	2004	2003
Net cash flow as a result of accounts receivable financing	$ 7	$ (28)
Collections from customers	$ 4,541	$ 4,361

Dividend Restrictions: Under the provisions of our articles of incorporation, at December 31, 2004, we had $456 million of unrestricted retained earnings available to pay common stock dividends. However, covenants in our debt facilities cap common stock dividend payments at $300 million in a calendar year. In October 2004, the MPSC rescinded

its December 2003 interim gas rate order, which included a $190 million annual dividend cap. For the year ended December 31, 2004, we paid $190 million in common stock dividends to CMS Energy.

Preferred Stock: Our Preferred Stock outstanding follows:

December 31	Series	Optional Redemption Price	Number of Shares 2004	Number of Shares 2003	In Millions 2004	In Millions 2003
Preferred Stock						
Cumulative $100 par value,						
Authorized 7,500,000 shares,						
with no mandatory redemption	$4.16	$103.25	68,451	68,451	$ 7	$ 7
	$4.50	$110.00	373,148	373,148	37	37
Total Preferred Stock					$ 44	$ 44

FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others:* This Interpretation became effective January 2003. It describes the disclosure to be made by a guarantor about its obligations under certain guarantees that it has issued. At the inception of a guarantee, it requires a guarantor to recognize a liability for the fair value of the obligation undertaken in issuing the guarantee. The initial recognition and measurement provision of this Interpretation does not apply to some guarantee contracts, such as warranties, derivatives, or guarantees between either parent and subsidiaries or corporations under common control, although disclosure of these guarantees is required. For contracts that are within the recognition and measurement provision of this Interpretation, the provisions were to be applied to guarantees issued or modified after December 31, 2002.

The following table describes our guarantees at December 31, 2004:

Guarantee Description	Issue Date	Expiration Date	Maximum Obligation	Carrying Amount	In Millions Recourse Provision (a)
Standby letters of credit	Various	Various	$ 25	$ -	$ -
Surety bonds	Various	Various	6	-	-
Nuclear insurance retrospective premiums	Various	Various	134	-	-

(a) Recourse provision indicates the approximate recovery from third parties including assets held as collateral.

The following table provides additional information regarding our guarantees:

Guarantee Description	How Guarantee Arose	Events That Would Require Performance
Standby letters of credit	Normal operations of coal power plants	Noncompliance with environmental regulations and non-responsive to demands for corrective action
	Natural gas transportation	Nonperformance
	Self-insurance requirement	Nonperformance
	Nuclear plant closure	Nonperformance

Surety bonds	Normal operating activity, permits and license	Nonperformance
Nuclear insurance retrospective premiums	Normal operations of nuclear plants	Call by NEIL and Price-Anderson Act for nuclear incident

4: Financial and Derivative Instruments

Financial Instruments: The carrying amounts of cash, short-term investments, and current liabilities approximate their fair values because of their short-term nature. We estimate the fair values of long-term financial instruments based on quoted market prices or, in the absence of specific market prices, on quoted market prices of similar instruments or other valuation techniques.

The cost and fair value of our long-term financial instruments are as follows:

In Millions

December 31	2004			2003		
	Cost	Fair Value	Unrealized Gain (Loss)	Cost	Fair Value	Unrealized Gain (Loss)
Long-term debt (a)	$ 4,118	$ 4,232	$ (114)	$ 3,611	$ 3,711	$ (100)
Long-term debt - related parties (b)	506	518	(12)	506	518	(12)
Available-for-sale securities:						
Common stock of CMS Energy (c)	10	25	15	10	20	10
SERP:						
Equity securities	15	21	6	10	14	4
Debt securities (e)	9	9	-	7	7	-
Nuclear decommissioning investments (d):						
Equity securities	136	262	126	143	260	117
Debt securities (e)	291	302	11	288	304	16

(a) Includes current maturities of $118 million at December 31, 2004 and $28 million at December 31, 2003. Settlement of long-term debt is generally not expected until maturity.

(b) Includes current maturities of $180 million at December 31, 2004.

(c) At December 31, 2004, we held 2.4 million shares of CMS Energy Common Stock.

(d) Nuclear decommissioning investments include cash and equivalents and accrued income totaling $11 million at December 31, 2004 and $11 million at December 31, 2003. Unrealized gains and losses on nuclear decommissioning investments are reflected as regulatory liabilities.

(e) The fair value of available-for-sale debt securities by contractual maturity as of December 31, 2004 is as follows:

	In Millions
Due in one year or less	$ 31
Due after one year through five years	122
Due after five years through ten years	120
Due after ten years	38
Total	$311

Our held-to-maturity investments consist of debt securities held by the MCV Partnership totaling $139 million as of December 31, 2004. These securities represent funds restricted primarily for future lease payments and are classified as Other assets on our Consolidated Balance Sheets. These investments have original maturity dates of approximately one year or less and, because of their short maturities, their carrying amounts approximate their fair values.

Derivative Instruments: We are exposed to market risks including, but not limited to, changes in interest rates, commodity prices, and equity security prices. We manage these risks using established policies and procedures, under the direction of both an executive oversight committee consisting of senior management representatives and a risk committee consisting of business-unit managers. We may use various contracts to manage these risks including swaps, options, futures, and forward contracts.

We intend that any gains or losses on these contracts will be offset by an opposite movement in the value of the item at risk. We enter into all risk management contracts for purposes other than trading. These contracts contain credit risk if the counterparties, including financial institutions and energy marketers, fail to perform under the agreements. We minimize such risk through established credit policies that include performing financial credit reviews of our counterparties. Determination of our counterparties' credit quality is based upon a number of factors, including credit ratings, disclosed financial condition, and collateral requirements. Where contractual terms permit, we employ standard agreements that allow for netting of positive and negative exposures associated with a single counterparty. Based on these policies and our current exposures, we do not anticipate a material adverse effect on our financial position or earnings as a result of counterparty nonperformance.

Contracts used to manage market risks may be considered derivative instruments that are subject to derivative and hedge accounting pursuant to SFAS No. 133. If a contract is accounted for as a derivative instrument, it is recorded in the financial statements as an asset or a liability, at the fair value of the contract. The recorded fair value is then adjusted quarterly to reflect any change in the market value of the contract, a practice known as marking the contract to market. Changes in fair value (that is, gains or losses) are reported either in earnings or accumulated other comprehensive income, depending on whether the derivative qualifies for cash flow hedge accounting treatment.

For derivative instruments to qualify for hedge accounting, the hedging relationship must be formally documented at inception and be highly effective in achieving offsetting cash flows or offsetting changes in fair value attributable to the risk being hedged. If hedging a forecasted transaction, the forecasted transaction must be probable. If a derivative instrument, used as a cash flow hedge, is terminated early because it is probable that a forecasted transaction will not occur, any gain or loss as of such date is recognized immediately in earnings. If a derivative instrument, used as a cash flow hedge, is terminated early for other economic reasons, any gain or loss as of the termination date is deferred and recorded when the forecasted transaction affects earnings. The ineffective portion, if any, of all hedges is recognized in earnings.

We use a combination of quoted market prices, prices obtained from external sources, such as brokers, and mathematical valuation models to determine the fair value of those contracts requiring derivative accounting. In certain contracts, long-term commitments may extend beyond the period in which market quotations for such contracts are available. Mathematical models are developed to determine various inputs into the fair value calculation including price and other variables that may be required to calculate fair value. Realized cash returns on these commitments may vary, either positively or negatively, from the results estimated through application of the mathematical model. In connection with the market valuation of our derivative contracts, we maintain reserves, if necessary, for credit risks based on the financial condition of counterparties.

The majority of our contracts are not subject to derivative accounting under SFAS No. 133 because they qualify for the

normal purchases and sales exception, or because there is not an active market for the commodity. Our electric capacity and energy contracts are not accounted for as derivatives due to the lack of an active energy market in the state of Michigan and the significant transportation costs that would be incurred to deliver the power under the contracts to the closest active energy market at the Cinergy hub in Ohio. Similarly, our coal purchase contracts are not accounted for as derivatives due to the lack of an active market for the coal that we purchase. If active markets for these commodities develop in the future, we may be required to account for these contracts as derivatives, and the resulting mark-to-market impact on earnings could be material to our financial statements..

The MISO is scheduled to begin the Midwest Energy Market on April 1, 2005, which will include day-ahead and real-time energy market information and centralized dispatch for market participants. At this time, we believe that the commencement of this market will not constitute the development of an active energy market in the state of Michigan. However, after having adequate experience with the Midwest Energy Market, we will reevaluate whether or not the activity level within this market leads to the conclusion that an active energy market exists.

Derivative accounting is required for certain contracts used to limit our exposure to commodity price risk. The following table reflects the fair value of all contracts requiring derivative accounting:

In Millions

December 31	2004			2003		
Derivative Instruments	Cost	Fair Value	Unrealized Gain (Loss)	Cost	Fair Value	Unrealized Gain (Loss)
Gas contracts	$ 2	$ -	$ (2)	$ 3	$ 2	$ (1)
Derivative contracts associated with Consumers' investment in the MCV Partnership:						
Prior to consolidation (a)	-	-	-	-	15	15
After consolidation:						
Gas fuel contracts	-	56	56	-	-	-
Gas fuel futures and swaps	-	64	64	-	-	-

(a) The amount associated with derivative contracts held by the MCV Partnership as of December 31, 2003 represents our proportionate share of the unrealized gain on those contracts accounted for as cash flow hedges included in Accumulated other comprehensive income. Our proportionate share of the total fair value of all derivative instruments held by the MCV Partnership as of December 31, 2003 was $51 million, and is included in Investments – Midland Cogeneration Venture Limited Partnership on our Consolidated Balance Sheets.

The fair value of our derivative contracts is included in Derivative instruments, Other assets, or Other liabilities on our Consolidated Balance Sheets.

Gas Contracts: Our gas utility business uses fixed-priced weather-based gas supply call options and fixed-priced gas supply call and put options to meet our regulatory obligation to provide gas to our customers at a reasonable and prudent cost. Unrealized gains and losses associated with these options are reported directly in earnings as part of Other income, and then directly offset in earnings and recorded on the balance sheet as a regulatory asset or liability as part of the GCR process. At December 31, 2004, we held fixed-priced weather-based gas supply call options and had sold fixed-priced gas supply put options.

Derivative Contracts Associated with Consumers' Investment in the MCV Partnership:

Gas Fuel Contracts: The MCV Partnership uses natural gas fuel contracts to buy gas as fuel for generation, and to manage gas fuel costs. The MCV Partnership believes that certain of its long-term natural gas contracts qualify as normal purchases under SFAS No. 133, and therefore, these contracts were not recognized at fair value on the balance sheet as of December 31, 2004. The MCV Partnership also held certain long-term gas contracts that did not qualify as normal purchases as of December 31, 2004, because these contracts contained volume optionality. Accordingly, these contracts were accounted for as derivatives, with changes in fair value recorded in earnings each quarter. The MCV Partnership expects future earnings volatility on these contracts, since gains and losses will be recorded each quarter. For the year ended December 31, 2004, we recorded a $19 million net loss associated with these gas contracts in Fuel for electric generation on our Consolidated Statements of Income. The fair value of these contracts will reverse over the remaining life of the contracts ranging from 2005 to 2007.

Due to the implementation of the RCP in January 2005, the MCV Partnership has determined that a significant portion of its gas fuel contracts no longer qualify as normal purchases because the contracted gas will not be consumed for electric production. Accordingly, these contracts will be treated as derivatives and will be marked-to-market through earnings each quarter, which could increase earnings volatility. Based on market prices for natural gas as of January 31, 2005, the accounting for the MCV Partnership's long-term gas contracts, including those affected by the implementation of the RCP, could result in an estimated $100 million (pretax before minority interest) gain recorded to earnings in the first quarter of 2005. This estimated gain will reverse in subsequent quarters as the contracts settle. For further details on the RCP, see Note 2, Contingencies, "Other Electric Contingencies – The Midland Cogeneration Venture." If there are further changes in the level of planned electric production or gas consumption, the MCV Partnership may be required to account for additional long-term gas contracts as derivatives, which could add to earnings volatility.

Gas Fuel Futures and Swaps: The MCV Partnership enters into natural gas futures contracts, option contracts, and over-the-counter swap transactions in order to hedge against unfavorable changes in the market price of natural gas in future months when gas is expected to be needed. These financial instruments are used principally to secure anticipated natural gas requirements necessary for projected electric and steam sales, and to lock in sales prices of natural gas previously obtained in order to optimize the MCV Partnership's existing gas supply, storage, and transportation arrangements. At December 31, 2004, the MCV Partnership held gas fuel futures and swaps.

The contracts that are used to secure anticipated natural gas requirements necessary for projected electric and steam sales qualify as cash flow hedges under SFAS No. 133. The MCV Partnership also engages in cost mitigation activities to offset the fixed charges the MCV Partnership incurs in operating the MCV Facility. These cost mitigation activities include the use of futures and options contracts to purchase and/or sell natural gas to maximize the use of the transportation and storage contracts when it is determined that they will not be needed for the MCV Facility operation. Although these cost mitigation activities do serve to offset the fixed monthly charges, these cost mitigation activities are not considered a normal course of business for the MCV Partnership and do not qualify as hedges. Therefore, the mark-to-market gains and losses from these cost mitigation activities are recorded in earnings each quarter.

As of December 31, 2004, we have recorded a cumulative net gain of $21 million, net of tax, in Accumulated other comprehensive income relating to our proportionate share of the contracts held by the MCV Partnership that qualify as cash flow hedges. This balance represents natural gas futures, options, and swaps with maturities ranging from January 2005 to December 2009, of which $11 million of this gain is expected to be reclassified as an increase to earnings during the next 12 months. In addition, for the year ended December 31, 2004, we recorded a net gain of $37 million in earnings from hedging activities related to natural gas requirements for the MCV Facility operations and a net gain of $2 million in earnings from the MCV Partnership's cost mitigation activities.

5: Retirement Benefits

We provide retirement benefits to our employees under a number of different plans, including:

- non-contributory, defined benefit Pension Plan,
- a cash balance pension plan for certain employees hired after June 30, 2003,
- benefits to certain management employees under SERP,
- a defined contribution 401(k) plan,
- benefits to a select group of management under EISP, and
- health care and life insurance benefits under OPEB.

Pension Plan: The Pension Plan includes funds for our employees and our non-utility affiliates, including Panhandle. The Pension Plan's assets are not distinguishable by company.

In June 2003, CMS Energy sold Panhandle to Southern Union Panhandle Corp. No portion of the Pension Plan assets were transferred with the sale and Panhandle employees are no longer eligible to accrue additional benefits. The Pension Plan retained pension payment obligations for Panhandle employees that were vested under the Pension Plan.

The sale of Panhandle resulted in a significant change in the makeup of the Pension Plan. A remeasurement of the obligation was required at the date of sale. The remeasurement further resulted in the following:

- an increase in OPEB expense of $4 million for 2003, and
- an additional charge to accumulated other comprehensive income of $31 million ($20 million after-tax) in 2003 as a result of the increase in the additional minimum pension liability. As a result of company contributions in 2003, the additional minimum pension liability was eliminated as of December 31, 2003.

In 2003, a substantial number of retiring employees elected a lump sum payment instead of receiving pension benefits as an annuity over time. Lump sum payments constitute a settlement under SFAS No. 88. A settlement loss must be recognized when the cost of all settlements paid during the year exceeds the sum of the service and interest costs for that year. We recorded a settlement loss of $48 million ($31 million after-tax) in December 2003.

SERP: SERP benefits are paid from a trust established in 1988. SERP is not a qualified plan under the Internal Revenue Code; SERP trust earnings are taxable and trust assets are included in consolidated assets. Trust assets were $30 million at December 31, 2004, and $22 million at December 31, 2003. The assets are classified as Other non-current assets. The Accumulated Benefit Obligation for SERP was $30 million at December 31, 2004 and $19 million at December 31, 2003.

401k: Employer matching contributions to the 401(k) plan are invested in CMS Energy common stock. The amount charged to expense for this plan was $8 million in 2002. The employer's match for the 401(k) plan was suspended on September 1, 2002 and was resumed on January 1, 2005.

The MCV Partnership sponsors a defined contribution retirement plan covering all employees. Under the terms of the plan, the MCV Partnership makes contributions of either 5 or 10 percent of an employee's eligible annual compensation dependent upon the employee's age. The MCV Partnership also sponsors a 401(k) savings plan for employees. Contributions and costs for this plan are based on matching an employee's savings up to a maximum level. Amounts contributed under these plans were $1 million in 2004.

EISP: We implemented an EISP in 2002 to provide flexibility in separation of employment by officers, a select group of

management, or other highly compensated employees. Terms of the plan may include payment of a lump sum, payment of monthly benefits for life, payment of premium for continuation of health care, or any other legally permissible term deemed to be in our best interest to offer. As of December 31, 2004, the Accumulated Benefit Obligation of the EISP was $4 million.

OPEB: Retiree health care costs at December 31, 2004 are based on the assumption that costs would increase 7.5 percent in 2004. The rate of increase is expected to be 10 percent for 2005. The rate of increase is expected to slow to an estimated 5 percent by 2010 and thereafter.

The MCV Partnership sponsors defined cost postretirement health care plans that cover all full-time employees, except key management. Participants in the postretirement health care plans become eligible for the benefits if they retire on or after the attainment of age 65 or upon a qualified disability retirement, or if they have 10 or more years of service and retire at age 55 or older. The accumulated benefit obligation of the MCV Partnership's postretirement plans was $5 million at December 31, 2004. The MCV Partnership's net periodic postretirement health care cost for 2004 was less than $1 million.

The health care cost trend rate assumption affects the estimated costs recorded. A one-percentage point change in the assumed health care cost trend assumption would have the following effects:

	In Millions	
	One Percentage Point Increase	One percentage Point Decrease
Effect on total service and interest cost component	$ 12	$ (10)
Effect on postretirement benefit obligation	$ 149	$ (129)

We adopted SFAS No. 106, effective as of the beginning of 1992. We recorded a liability of $466 million for the accumulated transition obligation and a corresponding regulatory asset for anticipated recovery in utility rates. For additional details, see Note 1, Corporate Structure and Accounting Policies, "Utility Regulation." The MPSC authorized recovery of the electric utility portion of these costs in 1994 over 18 years and the gas utility portion in 1996 over 16 years.

The measurement date for all of Consumers' plans is November 30 for 2004, and December 31 for 2003 and 2002. We believe accelerating the measurement date on our benefit plans by one month is preferable as it improves control procedures and allows more time to review the completeness and accuracy of the actuarial measurements. As a result of the measurement date change in 2004, we recorded a $1 million cumulative effect of change in accounting, net of tax benefit, as a decrease to earnings. We also increased the amount of accrued benefit cost on our Consolidated Balance Sheets by $2 million. The effect of the measurement date change was immaterial. The measurement date for the MCV Partnership's plan is December 31, 2004.

Assumptions: The following table recaps the weighted-average assumptions used in our retirement benefits plans to determine the benefit obligation and net periodic benefit cost:

	Pension & SERP			OPEB		
	2004	2003	2002	2004	2003	2002
Discount rate	6.00%	6.25%	6.75%	6.00%	6.25%	6.75%
Expected long-term rate of return on						

plan assets (a)						
Union				8.75%	8.75%	8.75%
Non-Union				6.00%	6.00%	6.00%
Rate of compensation increase:						
Pension	3.50%	3.25%	3.50%			
SERP	5.50%	5.50%	5.50%			

(a) We determine our long-term rate of return by considering historical market returns, the current and future economic environment, the capital market principals of risk and return, and the expert opinions of individuals and firms with financial market knowledge. We use the asset allocation of the portfolio to forecast the future expected total return of the portfolio. The goal is to determine a long-term rate of return that can be incorporated into the planning of future cash flow requirements in conjunction with the change in the liability. The use of forecasted returns for various classes of assets used to construct an expected return model is reviewed periodically for reasonability and appropriateness.

Costs: The following table recaps the costs incurred in our retirement benefits plans:

	8.75%	8.75%	8.75%			In Millions
	Pension & SERP			OPEB		
Years Ended December 31	2004	2003	2002	2004	2003	2002
Service cost	$36	$39	$ 40	$18	$ 17	$ 16
Interest expense	77	75	86	54	61	63
Expected return on plan assets	(109)	(80)	(103)	(45)	(39)	(40)
Plan amendments	-	-	4	-	-	-
Settlement charge	-	48	-	-	-	-
Amortization of:						
Net loss	14	9	-	11	18	8
Prior service cost	6	7	8	(8)	(6)	(1)
Net periodic pension and postretirement benefit cost	$24	$98	$ 35	$30	$ 51	$ 46

Reconciliations: The following table reconciles the funding of our retirement benefits plans with our retirement benefits plans' liability:

						In Millions
	Pension Plan		SERP		OPEB	
Years Ended December 31	2004	2003	2004	2003	2004	2003
Benefit obligation at beginning of period	$ 1,189	$ 1,256	$ 22	$ 21	$ 812	$ 890
Service cost	35	38	1	1	18	17
Interest cost	74	74	3	1	54	61
Plan amendment	-	(19)	-	-	-	(44)
Employee Transfers	-	-	12	-	-	-
Actuarial loss	138	55	3	-	168	(72)
Benefits paid	(108)	(215)	(1)	(1)	(39)	(40)
Benefit obligation at end of period (a)	1,328	1,189	40	22	1,013	812
Plan assets at fair value at beginning of period	1,067	607	-	-	564	465

Actual return on plan assets	81	115	-	-	25	68
Company contribution	-	560	-	-	48	71
Actual benefits paid	(108)	(215)	-	-	(39)	(40)
Plan assets at fair value at end of period	1,040	1,067	-	-	598	564
Benefit obligation in excess of plan assets	(288)	(122)	(40)	(22)	(415)	(248)
Unrecognized net loss from experience different than assumed	642	501	6	3	347	164
Unrecognized prior service cost (benefit)	23	29	-	-	(99)	(107)
Net Balance Sheet Asset (Liability)	377	408	(34)	(19)	(167)	(191)
Additional VEBA Contributions or Non-Trust Benefit Payments					15	-
Additional minimum liability adjustment (b)	(419)	-	-	-	-	-
Total Net Balance Sheet Asset (Liability)	$ (42)	$ 408	$ (34)	$ (19)	$ (152)	$ (191)

(a) The Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law in December 2003. The Act establishes a prescription drug benefit under Medicare (Medicare Part D), and a federal subsidy, which is tax-exempt, to sponsors of retiree health care benefit plans that provide a benefit that is actuarially equivalent to Medicare Part D.

We believe our plan is actuarially equivalent to Medicare Part D and have incorporated, retroactively, the effects of the subsidy into our financial statements as of June 30, 2004, in accordance with FASB Staff Position, No. SFAS 106-2. We remeasured our obligation as of December 31, 2003 to incorporate the impact of the Act, which resulted in a reduction to the accumulated postretirement benefit obligation of $148 million. The remeasurement resulted in a reduction of OPEB cost of $23 million for 2004. The reduction of $23 million includes $7 million in capitalized OPEB costs. For additional details, see Note 13, Implementation of New Accounting Standards.

(b) The Pension Plan's Accumulated Benefit Obligation of $1.082 billion exceeded the value of the Pension Plan assets and net balance sheet asset at December 31, 2004. As a result, we recorded an additional minimum liability of $419 million. Consistent with MPSC guidance, Consumers recognized the cost of their additional minimum liability as a regulatory asset. Accordingly, Consumers' additional minimum liability includes an intangible asset of $21 million, and a regulatory asset of $372 million. The Accumulated Benefit Obligation for the Pension Plan was $1.019 billion at December 31, 2003.

Plan Assets: The following table recaps the categories of plan assets in our retirement benefits plans:

	Pension		OPEB	
	2004	2003	2004	2003
Asset Category:				
Fixed Income	34%	52%(b)	45%	51%
Equity Securities	61%	44%	54%	48%
CMS Energy Common Stock (a)	5%	4%	1%	1%

(a) At November 30, 2004, there were 4,892,000 shares of CMS Energy Common Stock in the Pension Plan assets with a

fair value of $50 million, and 493,000 shares in the OPEB plan assets, with a fair value of $5 million. At December 31, 2003, there were 4,970,000 shares of CMS Energy Common Stock in the Pension Plan assets with a fair value of $42 million, and 414,000 shares in the OPEB plan assets, with a fair value of $4 million.

(b) The percentage of fixed income at December 31, 2003 is high because our December contribution of $329 million was deposited temporarily into fixed income securities.

We contributed $62 million to our OPEB plan in 2004. We plan to contribute $62 million to our OPEB plan in 2005. We did not contribute to our Pension Plan in 2004. We do not plan to contribute to our Pension Plan in 2005.

We have established a target asset allocation for our Pension Plan assets of 65 percent equity and 35 percent fixed income investments to maximize the long-term return on plan assets, while maintaining a prudent level of risk. The level of acceptable risk is a function of the liabilities of the plan. Equity investments are diversified mostly across the Standard & Poor's 500 Index, with a lesser allocation to the Standard & Poor's Mid Cap and Small Cap Indexes and a Foreign Equity Index Fund. Fixed income investments are diversified across investment grade instruments of both government and corporate issuers. Annual liability measurements, quarterly portfolio reviews, and periodic asset/liability studies are used to evaluate the need for adjustments to the portfolio allocation.

We have established union and non-union VEBA trusts to fund our future retiree health and life insurance benefits. These trusts are funded through the rate making process for Consumers, and through direct contributions from the non-utility subsidiaries. The equity portions of the union and non-union health care VEBA trusts are invested in a Standard & Poor's 500 Index fund. The fixed income portion of the union health care VEBA trust is invested in domestic investment grade taxable instruments. The fixed income portion of the non-union health care VEBA trust is invested in a diversified mix of domestic tax-exempt securities. The investment selections of each VEBA are influenced by the tax consequences, as well as the objective of generating asset returns that will meet the medical and life insurance costs of retirees.

Benefit Payments: The expected benefit payments for each of the next five years and the five-year period thereafter are as follows:

			In Millions
	Pension	SERP	OPEB(a)
2005	$113	$2	$53
2006	105	2	51
2007	96	2	53
2008	90	2	54
2009	89	2	56
2010-2014	423	13	322

(a) OPEB benefit payments are net of employee contributions and expected Medicare Part D subsidy payments.

6: Asset Retirement Obligations

SFAS No. 143: This standard became effective January 2003. It requires companies to record the fair value of the cost to remove assets at the end of their useful life, if there is a legal obligation to remove them. We have legal obligations to remove some of our assets, including our nuclear plants, at the end of their useful lives. As required by SFAS No. 71, we accounted for the implementation of this standard by recording regulatory assets and liabilities instead of a cumulative effect of a change in accounting principle.

The fair value of ARO liabilities has been calculated using an expected present value technique. This technique reflects assumptions such as costs, inflation, and profit margin that third parties would consider to assume the settlement of the obligation. Fair value, to the extent possible, should include a market risk premium for unforeseeable circumstances. No market risk premium was included in our ARO fair value estimate since a reasonable estimate could not be made. If a five percent market risk premium were assumed, our ARO liability would increase by $22 million.

If a reasonable estimate of fair value cannot be made in the period in which the ARO is incurred, such as for assets with indeterminate lives, the liability is to be recognized when a reasonable estimate of fair value can be made. Generally, gas transmission and electric and gas distribution assets have indeterminate lives. Retirement cash flows cannot be determined and there is a low probability of a retirement date. Therefore, no liability has been recorded for these assets. Also, no liability has been recorded for assets that have insignificant cumulative disposal costs, such as substation batteries. The measurement of the ARO liabilities for Palisades and Big Rock are based on decommissioning studies that largely utilize third-party cost estimates.

The following tables describe our assets that have legal obligations to be removed at the end of their useful life:

December 31, 2004			In Millions
ARO Description	In Service Date	Long Lived Assets	Trust Fund
Palisades – decommission plant site	1972	Palisades nuclear plant	$523
Big Rock – decommission plant site	1962	Big Rock nuclear plant	52
JHCampbell intake/discharge water line	1980	Plant intake/discharge water line	-
Closure of coal ash disposal areas	Various	Generating plants coal ash areas	-
Closure of wells at gas storage fields	Various	Gas storage fields	-
Indoor gas services equipment relocations	Various	Gas meters located inside structures	-

						In Millions
ARO Description	ARO Liability 1/1/03	Incurred	Settled	Accretion	Cash flow Revisions	ARO Liability 12/31/03
Palisades - decommission	$249	$ -	$ -	$19	$ -	$268
Big Rock - decommission	61	-	(40)	13	-	34
JHCampbell intake line	-	-	-	-	-	-
Coal ash disposal areas	51	-	(3)	5	-	53
Wells at gas storage fields	2	-	-	-	-	2
Indoor gas services relocations	1	-	-	-	-	1
Total	$364	$ -	$(43)	$37	$ -	$358

In Millions

ARO Description	ARO Liability 12/31/03	Incurred	Settled	Accretion	Cash flow Revisions	ARO Liability 12/31/04
Palisades - decommission	$268	$ -	$ -	$22	$60	$350
Big Rock – decommission	34	-	(40)	14	22	30
JHCampbell intake line	-	-	-	-	-	-
Coal ash disposal areas	53	-	(4)	5	-	54
Wells at gas storage fields	2	-	(1)	-	-	1
Indoor gas services relocations	1	-	-	-	-	1
Total	$358	$ -	$(45)	$41	$82	$436

The Palisades and Big Rock cash flow revisions resulted from new decommissioning reports filed with the MPSC in March 2004. The Palisades ARO also reflects a cash flow revision for the probability of operating license renewal; the renewal would extend the plant's operating license by twenty years. For additional details, see Note 2, Contingencies, "Other Electric Contingencies – Nuclear Plant Decommissioning."

On October 14, 2004 the MPSC issued a generic proceeding to review SFAS No. 143, *Accounting for Asset Retirement Obligations*, FERC Order No. 631, *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, and their accounting and ratemaking issues. Utilities are required to respond to the Order by March 15, 2005. We consider the proceeding a clarification of accounting and reporting issues that relate to all Michigan utilities; we anticipate no financial impact.

7: Income Taxes

We file a consolidated federal income tax return with CMS Energy. Income taxes are generally allocated based on each company's separate taxable income. We had tax related receivables from CMS Energy of $4 million in 2004 and $46 million in 2003.

We practice deferred tax accounting for temporary differences in accordance with SFAS No. 109. We use ITC to reduce current income taxes payable, and defer and amortize ITC over the life of the related property. AMT paid generally becomes a tax credit that we can carry forward indefinitely to reduce regular tax liabilities in future periods when regular taxes paid exceed the tax calculated for AMT. At December 31, 2004, we had AMT credit carryforwards in the amount of $20 million that do not expire, and tax loss carryforwards in the amount of $69 million that expire in 2021 through 2023. In addition, at December 31, 2004, we had charitable contribution carryforwards in the amount of $13 million that expire in 2005 through 2008 and general business credit carryforwards in the amount of $4 million that primarily expire in 2005, for which a valuation allowance has been provided.

The significant components of income tax expense (benefit) consisted of:

In Millions

Years Ended December 31	2004	2003	2002
Current federal income taxes	$ 26	$ (58)	$ (97)
Current federal income tax benefit of operating loss	(11)	-	-

carryforwards			
Deferred federal income taxes	142	201	283
Deferred ITC, net	(5)	(6)	(6)
Income tax expense	$ 152	$ 137	$ 180

The principal components of our deferred tax assets (liabilities) recognized in the balance sheet are as follows:

	In Millions	
December 31	2004	2003
Property	$ (863)	$ (826)
Consolidated investments	(217)	(226)
Securitization costs	(176)	(186)
Gas inventories	(126)	(100)
Employee benefits	(79)	(90)
SFAS No. 109 regulatory liability	135	120
Nuclear decommissioning	63	59
Tax loss and credit carryforwards	52	42
Valuation allowance	(9)	(8)
Other, net	(150)	(51)
Net deferred tax liabilities	$(1,370)	$ (1,266)
Deferred tax liabilities	$ (2,102)	$ (1,967)
Deferred tax assets, net of valuation allowance	732	701
Net deferred tax liabilities	$ (1,370)	$ (1,266)

The actual income tax expense differs from the amount computed by applying the statutory federal tax rate of 35 percent to income before income taxes as follows:

		In Millions	
Years Ended December 31	2004	2003	2002
Income before cumulative effect of change in accounting principle	$ 280	$ 196	$ 363
Income tax expense	152	137	180
Preferred securities distributions (Note 3)	-	-	(44)
Pretax income	432	333	499
Statutory federal income tax rate	x 35%	x 35%	x 35%
Expected income tax expense	151	117	174
Increase (decrease) in taxes from:			
Property differences not previously deferred	13	18	18
OPEB Medicare subsidy	(5)	-	-

Loss on investment in CMS Energy Common Stock	-	4	4
Sale of METC	-	-	(5)
ITC amortization/adjustments	(6)	(6)	(6)
Valuation allowance provision	1	8	-
Affiliated companies' dividends	-	-	(1)
Other, net	(2)	(4)	(4)
Actual income tax expense	$ 152	$ 137	$ 180
Effective tax rate	35.2%	41.1%	36.1%

8: Executive Incentive Compensation

We provide a Performance Incentive Stock Plan (the Plan) to key employees and non-employee Directors or consultants based on their contributions to the successful management of the company. On May 28, 2004, shareholders approved an amendment to the Plan, with an effective date of June 1, 2004. The amendment established a 5-year term for the Plan. The Plan includes the following type of awards:

- phantom shares,
- performance units,
- restricted stock,
- stock options,
- stock appreciation rights, and
- management stock purchases.

Phantom shares are valued at the fair market price of common stock when granted. They give the holder the right to receive the appreciation value of common stock on one or more valuation dates, according to a specified vesting schedule determined at time of grant. These shares are subject to forfeiture if employment terminates before vesting.

Performance units have an initial value established at the time of grant. Performance criteria are established at the time of grant and, depending upon the extent to which they are met, will determine the value of the payout, which may be in the form of cash, common stock, or a combination of both. These units are subject to forfeiture if employment terminates.

Restricted shares of common stock are outstanding shares with full voting and dividend rights. These awards vest 100 percent after three years and are subject to achievement of specified levels of total shareholder return including a comparison to a peer group of companies. Some awards vest based solely on continued employment. These awards are subject to forfeiture if employment terminates before vesting. Restricted shares vest fully if control of CMS Energy changes, as defined by the Plan.

Stock options give the holder the right to purchase common stock at a given price over an extended period of time. Stock appreciation rights give the holder the right to receive common stock appreciation, defined as the excess of the market price of the stock at the date of exercise over the grant date price. All stock options and stock appreciation rights are valued at fair market price when granted. All options and rights may be exercised upon grant, and expire up to 10 years and one month from the date of grant.

Management stock purchases are the election of select participants in the Officer's Incentive Compensation Plan to

receive all or a portion of their incentive payments in the form of shares of restricted common stock or shares of restricted stock units. These participants may also receive awards of additional restricted common stock or restricted stock units provided the total value of these additional grants does not exceed $2.5 million for any fiscal year.

Under the revised Plan, shares awarded or subject to options, phantom shares and performance units may not exceed 6 million shares from June 2004 through May 2009, nor may such grants or awards to any participant exceed 250,000 shares in any fiscal year.

Shares for which payment or exercise is in cash, as well as shares or options that are forfeited, may be awarded or granted again under the Plan.

Awards of up to 5,482,690 shares of CMS Energy Common Stock may be issued as of December 31, 2004. All grants awarded under this Plan in 2004 were in the form of restricted stock.

The following table summarizes the restricted stock and stock options granted to our key employees under the Performance Incentive Stock Plan:

	Restricted Stock	Options	
CMS Energy Common Stock	Number of Shares	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2002	239,665	1,100,952	$ 30.93
Granted	163,890	490,600	$ 14.32
Exercised or Issued	(26,663)	(6,083)	$ 17.13
Forfeited or Expired	(56,172)	(65,080)	$ 32.03
Outstanding at December 31, 2002	320,720	1,520,389	$ 25.58
Granted	434,011	1,105,490	$6.35
Exercised or Issued	(22,812)	-	-
Forfeited or Expired	(69,372)	(31,667)	$26.25
Outstanding at December 31, 2003	662,547	2,594,212	$17.37
Granted	395,641	-	-
Exercised or Issued	(66,537)	(358,102)	$6.65
Forfeited or Expired	(128,449)	(151,218)	$29.98
Outstanding at December 31, 2004	863,202	2,084,892	$18.30

At December 31, 2004, 316,312 of the 863,202 shares of CMS Energy restricted common stock outstanding are subject to performance objectives. Compensation expense for restricted stock was $2 million in 2004, $4 million in 2003, and less than $1 million in 2002.

The following table summarizes our stock options outstanding at December 31, 2004:

Range of Exercise Prices	Number of Shares Outstanding and Exercisable	Weighted Average Remaining Life	Weighted Average Exercise Price

CMS Energy Common Stock:

$6.35 - $6.35	808,188	8.70 years	$ 6.35
$8.12 - $8.12	213,850	7.67 years	$ 8.12
$17.00 - $25.39	423,248	5.91 years	$ 20.48
$27.25 – $39.06	551,689	4.60 years	$34.09
$43.38 - $43.38	87,917	3.57 years	$43.38
$6.35 - $43.38	2,084,892	6.72 years	$18.30

In December 2002, we adopted the fair value based method of accounting for stock-based employee compensation, under SFAS No. 123, as amended by SFAS No. 148. We elected to adopt the prospective method recognition provisions of this Statement, which applies the recognition provisions to all awards granted, modified, or settled after the beginning of the fiscal year that the recognition provisions are first applied.

The following table summarizes the weighted average fair value of stock options granted:

Options Grant Date	2004 (a)	2003	2002 (b)
Fair value at grant date	-	$3.04	$3.79, $1.40

(a) There were no stock option grants during 2004.
(b) For 2002, there were two stock option grants totaling 490,600 options.

The stock options fair value is estimated using the Black-Scholes model, a mathematical formula used to value options traded on securities exchanges. The following assumptions were used in the Black-Scholes model:

Years Ended December 31	2004 (a)	2003	2002 (b)
CMS Energy Common Stock Options			
Risk-free interest rate	-	3.23%	4.02%, 3.28%
Expected stock price volatility	-	53.10%	31.64%, 39.67%
Expected dividend rate	-	-	$ .365, $ .1825
Expected option life (years)	-	4.7	4.5

(a) There were no stock option grants during 2004.
For 2002, there were two stock option grants totaling 490,600 options.

We recorded $3 million as stock-based employee compensation cost for 2003, and $1 million for 2002. All stock options vest at date of grant.

9: Leases

We lease various assets, including vehicles, railcars, construction equipment, furniture, and buildings. We have both full-service and net leases. A net lease requires us to pay for taxes, maintenance, operating costs, and insurance. Most of our leases contain options at the end of the initial lease term to:

- purchase the asset at fair value, or

- renew the lease at fair rental value.

Our capital leases are comprised mainly of leased service vehicles and office furniture. As of December 31, 2004, capital lease obligations totaled $58 million. We are authorized by the MPSC to record both capital and operating lease payments as operating expense and recover the total cost from our customers. Capital lease expenses were $13 million in 2004, $17 million in 2003, and $20 million in 2002. In November 2003, we exercised our purchase option under the capital lease agreement for our main headquarters building in Jackson, Michigan. Operating lease charges were $13 million in 2004, $13 million in 2003, and $13 million in 2002.

In order to obtain permanent financing for the MCV Facility, the MCV Partnership entered into a sale and lease back agreement with a lessor group, which includes the FMLP, for substantially all of the MCV Partnership's fixed assets. In accordance with SFAS No. 98, the MCV Partnership accounts for the transaction as a financing arrangement. As of December 31, 2004, finance lease obligations totaled $286 million, which represents the third-party portion of the MCV Partnership's finance lease obligation. Charges under the MCV Partnership's finance lease obligation were $105 million in 2004. For additional details on transactions with the MCV Partnership and the FMLP, see Note 2, Contingencies, "Other Electric Contingencies – The Midland Cogeneration Venture."

Minimum annual rental commitments under our non-cancelable leases at December 31, 2004 were:

			In Millions
	Capital Leases	Finance Lease	Operating Leases
2005	$ 13	$ 19	$ 13
2006	13	18	12
2007	12	18	10
2008	10	19	10
2009	8	20	7
2010 and thereafter	15	192	28
Total minimum lease payments	71	286	$ 80
Less imputed interest	13	-	
Present value of net minimum lease payments	58	286	
Less current portion	10	19	
Non-current portion	$ 48	$ 267	

10: Summarized Financial Information of Significant Related Energy Supplier

Under Revised FASB Interpretation No. 46, we are the primary beneficiary of the MCV Partnership. We consolidated their assets, liabilities, and financial activities into our financial statements as of and for the year ended December 31, 2004. As of December 31, 2004, the MCV Partnership had total assets of $1.980 billion and a net loss of $24 million for the year. For 2003 and 2002, the MCV Partnership was accounted for as an equity method investment and their summarized financial information is shown below. Our 49 percent investment in the MCV Partnership was $419 million at December 31, 2003 and our share of net income was $29 million for the year ended December 31, 2003 and $65 million for the year ended December 31, 2002.

Under the PPA with the MCV Partnership discussed in Note 2, Contingencies, our 2003 obligation to purchase electric

capacity from the MCV Partnership provided 15 percent of our owned and contracted electric generating capacity. Summarized financial information of the MCV Partnership for 2003 and 2002 follows:

Statements of Income

	In Millions	
Years Ended December 31	2003	2002
Operating revenue (a)	$584	$597
Operating expenses	416	409
Operating income	168	188
Other expense, net	108	114
Income before cumulative effect of accounting change	60	74
Cumulative effect of change in method of accounting for derivative options contracts (b)	-	58
Net Income	$ 60	$ 132

Balance Sheet

			In Millions
December 31	2003		2003
Assets		**Liabilities and Equity**	
Current assets (c)	$ 389	Current liabilities	$ 250
Plant, net	1,494	Non-current liabilities (d)	1,021
Other assets	187	Partners' equity (e)	799
	$ 2,070		$ 2,070

(a) Revenue from Consumers totaled $514 million in 2003 and $557 million in 2002.

(b) On April 1, 2002, the MCV Partnership implemented a new accounting standard for derivatives. As a result, the MCV Partnership began accounting for several natural gas contracts containing an option component at fair value. The MCV Partnership recorded a $58 million cumulative effect adjustment for the change in accounting principle as an increase to earnings. CMS Midland's 49 percent ownership share was $28 million ($18 million after-tax), which is reflected as a change in accounting principle on our Consolidated Statements of Income.

(c) Receivables from Consumers totaled $40 million for December 31, 2003.

(d) The FMLP is the sole beneficiary of a trust that is the lessor in a long-term direct finance lease with the MCV Partnership. CMS Holdings holds a 46.4 percent ownership interest in the FMLP. The MCV Partnership's lease obligations, assets, and operating revenues secure the FMLP's debt. The following table summarizes obligation and payment information regarding the direct finance lease:

		In Millions
December 31		2003
Balance Sheet:		
MCV Partnership:	Lease obligation	$ 894
FMLP:	Non-recourse debt	431
	Lease payment to service non-recourse debt (including interest)	158
CMS Holdings:	Share of interest portion of lease payment	37
	Share of principle portion of lease payment	36

		In Millions	
Years Ended December 31		2003	2002
Income Statement:			
FMLP:	Earnings	$ 32	$ 38

(e) CMS Midland's recorded investment in the MCV Partnership includes capitalized interest, which we are expensing over the life of our investment in the MCV Partnership. The financing agreements prohibit the MCV Partnership from distributing any cash to its owners until it meets certain financial test requirements. We do not anticipate receiving a cash distribution in the near future.

11: Jointly Owned Regulated Utility Facilities

We are required to provide only our share of financing for the jointly owned utility facilities. The direct expenses of the jointly owned plants are included in operating expenses. Operation, maintenance, and other expenses of these jointly owned utility facilities are shared in proportion to each participant's undivided ownership interest. The following table indicates the extent of our investment in jointly owned regulated utility facilities:

						In Millions	
	Ownership Share	Net Investment		Accumulated Depreciation		Construction Work in Progress	
December 31	(percent)	2004	2003	2004	2003	2004	2003
Campbell Unit 3	93.3	$284	$299	$339	$328	$158	$113
Ludington	51.0	79	84	91	87	-	(1)
Distribution	Various	77	74	33	32	6	5

12: Reportable Segments

Our reportable segments are strategic business units organized and managed by the nature of the products and services each provides. We evaluate performance based upon the net income of each segment. We operate principally in two segments, electric utility and gas utility.

The electric utility segment consists of regulated activities associated with the generation and distribution of electricity in the state of Michigan. The gas utility segment consists of regulated activities associated with the transportation, storage, and distribution of natural gas in the state of Michigan.

Accounting policies of the segments are the same as we describe in the summary of significant accounting policies. Our financial statements reflect the assets, liabilities, revenues, and expenses directly related to the electric and gas segment where it is appropriate. We allocate accounts between the electric and gas segments where common accounts are attributable to both segments. The allocations are based on certain measures of business activities, such as revenue, labor dollars, customers, other operation and maintenance expense, construction expense, leased property, taxes or functional surveys. For example, customer receivables are allocated based on revenue. Pension provisions are allocated based on labor dollars.

We account for inter-segment sales and transfers at current market prices and eliminate them in consolidated net income available to common stockholder by segment. The "Other" segment includes our consolidated special purpose entity for the sale of trade receivables, the MCV Partnership and the FMLP.

The following table shows our financial information by reportable segment:

In Millions

Years Ended December 31	2004	2003	2002
Operating Revenues			
Electric	$ 2,586	$ 2,590	$ 2,648
Gas	2,081	1,845	1,519
Other	44	-	2
	$ 4,711	$ 4,435	$ 4,169
Earnings from Equity Method Investees			
Other (a)	$ 1	$ 42	$ 53
Depreciation, Depletion and Amortization			
Electric	$ 189	$ 247	$ 228
Gas	112	128	118
Other	90	2	2
	$ 391	$ 377	$ 348
Interest Charges			
Electric	$ 204	$ 164	$ 111
Gas	65	51	36
Other	97	30	21
	$ 366	$ 245	$ 168
Income Tax Expense			
Electric	$ 120	$ 90	$ 138
Gas	40	35	33
Other (b)	(8)	12	9
	$ 152	$ 137	$ 180
Net Income Available to Common Stockholder			
Electric	$ 222	$ 167	$ 264
Gas	71	38	46
Other	(16)	(11)	25
	$ 277	$ 194	$ 335
Investments in Equity Method Investees			
Electric	$ 3	$ 2	$ 2
Other (c)	16	659	643
	$ 19	$ 661	$ 645
Total Assets			
Electric (d)	$ 7,289	$ 6,831	$ 6,058
Gas (d)	3,187	2,983	2,586
Other	2,335	931	954
	$ 12,811	$10,745	$ 9,598
Capital Expenditures (e)			
Electric	$ 360	$ 310	$ 437
Gas	137	135	181
Other	21	-	-
	$ 518	$ 445	$ 618

(a) 2002 excludes $28 million benefit due to the change in accounting for derivative instruments.

(b) 2002 excludes $10 million tax expense due to the change in accounting for derivative instruments.

(c) As of December 31, 2003, the trusts that hold the mandatorily redeemable Trust Preferred Securities were deconsolidated. The trusts are now included on our Consolidated Balance Sheets as Investments –Other.

(d) Amounts include a portion of our other common assets attributable to both the electric and gas utility businesses.

(e) Amounts include electric restructuring implementation plan, purchase of nuclear fuel, and other assets. Amounts also include a portion of capital expenditures for plant and equipment attributable to both the electric and gas utility businesses.

13: Implementation of new accounting standards

FASB Interpretation No. 46, *Consolidation of Variable Interest Entities:* The FASB issued this Interpretation in January 2003. The objective of the Interpretation is to assist in determining when one party controls another entity in circumstances where a controlling financial interest cannot be properly identified based on voting interests. Entities with this characteristic are considered variable interest entities. The Interpretation requires the party with the controlling financial interest, known as the primary beneficiary, in a variable interest entity to consolidate the entity.

In December 2003, the FASB issued Revised FASB Interpretation No. 46. For entities that had not previously adopted FASB Interpretation No. 46, Revised FASB Interpretation No. 46 provided an implementation deferral until the first quarter of 2004. As of and for the quarter ended March 31, 2004, we adopted Revised FASB Interpretation No. 46 for all entities.

We determined that we are the primary beneficiary of both the MCV Partnership and the FMLP. We have a 49 percent partnership interest in the MCV Partnership and a 46.4 percent partnership interest in the FMLP. Consumers is the primary purchaser of power from the MCV Partnership through a long-term power purchase agreement. The FMLP holds a 75.5 percent lessor interest in the MCV Facility, which results in Consumers holding a 35 percent lessor interest in the MCV Facility. Collectively, these interests make us the primary beneficiary of these entities. As such, we consolidated their assets, liabilities, and activities into our financial statements as of and for the year ended December 31, 2004. These partnerships have third-party obligations totaling $582 million at December 31, 2004. Property, plant, and equipment serving as collateral for these obligations has a carrying value of $1.426 billion at December 31, 2004. The creditors of these partnerships do not have recourse to the general credit of Consumers.

We determined that we are not the primary beneficiary of our trust preferred security structures. Accordingly, those entities were deconsolidated as of December 31, 2003. Company Obligated Trust Preferred Securities totaling $490 million that were previously included in mezzanine equity, were eliminated due to deconsolidation. At December 31, 2004, we reflected Long-term debt – related parties of $326 million, current portion of Long-term debt – related parties of $180 million, and an investment in related parties of $16 million.

We are not required to restate prior periods for the impact of this accounting change.

FASB Staff Position, No. SFAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003*: The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law in December 2003. The Act establishes a prescription drug benefit under Medicare (Medicare Part D) and a federal subsidy, which is exempt from federal taxation, to sponsors of retiree health care benefit plans that provide a benefit that is actuarially equivalent to Medicare Part D.

We believe our plan is actuarially equivalent to Medicare Part D and have incorporated retroactively the effects of the subsidy into our financial statements as of June 30, 2004, in accordance with FASB Staff Position, No. SFAS 106-2. We remeasured our obligation as of December 31, 2003 to incorporate the impact of the Act, which resulted in a reduction to the accumulated postretirement benefit obligation of $148 million. The remeasurement resulted in a total OPEB cost reduction of $23 million for 2004. Consumers capitalizes a portion of OPEB cost in accordance with regulatory accounting. As such, the remeasurement resulted in a net reduction of OPEB expense of $16 million for 2004.

EITF Issue No. 03-1, *The Meaning of Other-Than-Temporary Impairments*: The Issue addresses the definition of an other-than-temporary impairment of certain investments and provides additional disclosure requirements. The scope of EITF Issue No. 03-1 includes debt and equity securities accounted for under SFAS No. 115, debt and equity securities held by non-profit organizations under SFAS No. 124, and cost method investments under APB No. 18. We analyzed our in-scope investments under the guidance of this Issue and have provided additional disclosures.

FSP 109-1, Accounting and Disclosure Guidance for the Tax Deduction Provided to U.S. Based Manufacturers by the American Jobs Creation Act of 2004: The American Jobs Creation Act of 2004 provides for a deduction, starting in 2005, of a portion of the income from certain production activities, including the production of electricity. FSP 109-1 indicates that the deduction should be accounted for as a special deduction rather than a tax rate reduction under SFAS No. 109. We are currently studying this act for its impact on us; however, we do not anticipate a material amount of tax benefit from the domestic production activities deduction in the near future.

New Accounting Standards NOT YET EFFECTIVE

SFAS No. 123R, *Share-Based Payment*: The Statement requires companies to expense the grant date fair value of employee stock options and similar awards. The Statement also clarifies and expands SFAS No. 123's guidance in several areas, including measuring fair value, classifying an award as equity or as a liability, and attributing compensation cost to reporting periods.

In addition, this Statement amends SFAS No. 95, *Statement of Cash Flows*, to require that excess tax benefits related to the excess of the tax deductible amount over the compensation cost recognized be classified as a financing cash inflow rather than as a reduction of taxes paid in operating activities.

This Statement is effective for us as of the beginning of third quarter 2005. We adopted the fair value method of accounting for share-based awards effective December 2002, and therefore, expect this statement to have an insignificant impact on our results of operations when it becomes effective.

14: Quarterly financial and common stock information (unaudited)

	2004			
Quarters Ended	March 31	June 30	Sept. 30	Dec. 31
	In Millions			
Operating revenue (a)	$1,547	$923	$885	$1,356
Operating income (a)(d)	247	111	122	194
Income before cumulative effect of change in accounting Principle (d)	105	24	34	117
Cumulative effect of change in accounting (b)(c)	(1)	-	-	-

Net income (c)(d)	104	24	34	117
Preferred stock dividends	-	1	-	1
Net income available to common stockholder (c)(d)	104	23	34	116

(a) As of March 31, 2004, we determined that the MCV Partnership and the FMLP should be consolidated in accordance with revised FASB Interpretation No. 46. As such, we consolidated their financial activities into our financial statements as of and for the year ended December 31, 2004. For additional details, see Note 13, Implementation of New Accounting Standards.

(b) Net of tax.

(c) Quarterly data for March 31, 2004 differs from amounts previously reported as a result of accelerating the measurement date on our benefit plans by one month. For additional information, see Note 5, Retirement Benefits.

(d) Quarterly data for March 31, 2004 differs from amounts previously reported due to the remeasurement of our post retirement benefit obligation in accordance with FASB Staff Position, No. SFAS 106-2. For additional information, see Note 13, Implementation of New Accounting Standards.

	2003			
Quarters Ended	March 31	June 30	Sept. 30	Dec. 31
	In Millions			
Operating revenue	$1,442	$902	$879	$1,212
Operating income	233	139	115	96
Income (loss) before cumulative effect of change in accounting principle	110	52	44	(10)
Net income (loss)	110	52	44	(10)
Preferred stock dividends	-	1	-	1
Preferred securities distributions	11	11	11	(33)
Net income available to common stockholder	99	40	33	22

15: Income Taxes (Unconsolidated)

The significant components of income tax expense (benefit) consisted of:

	In Millions
Year Ended December 31	2004
Current federal income taxes	$ 14
Deferred income taxes	141
Deferred ITC, net	(4)
Income tax expense	$ 151

The actual income tax expense differs from the amount computed by applying the statutory federal tax rate of 35 percent to income before income taxes as follows:

	In Millions
Year Ended December 31	2004
Income before cumulative effect of change in accounting principle	$ 280
Income taxes	151
Pretax income	431
Statutory federal income tax rate	x 35%
Expected income tax expense	151
Increase (decrease) in taxes from:	
Differences not previously deferred	13
ITC amortization/adjustments	(4)
Tax exempt interest income	(3)
OPEB Medicare subsidy	(3)
Other, net	(1)
Actual income tax expense	$ 151

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION			
Line No.	Classification (a)	Total (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	10,497,016,318	7,276,803,670
4	Property Under Capital Leases	58,296,094	37,768,508
5	Plant Purchased or Sold	55,933	55,933
6	Completed Construction not Classified	0	
7	Experimental Plant Unclassified	0	
8	Total (3 thru 7)	10,555,368,345	7,314,628,111
9	Leased to Others	0	
10	Held for Future Use	22,108,265	21,364,801
11	Construction Work in Progress	340,580,582	298,364,572
12	Aquisition Adjustments	283,275	
13	Total Utility Plant (8 thru 12)	10,918,340,467	7,634,357,484
14	Accum Prov for Depr, Amort, & Depl	5,303,941,597	3,392,175,143
15	Net Utility Plant (13 less 14)	5,614,398,870	4,242,182,341
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	5,150,369,069	3,377,269,434
19	Amort & Depl of Producing Nat Gas Land/Land Right	8,356,420	
20	Amor of Underground Storage Land/Land Rights	3,969,642	
21	Amort of Other Utility Plant	141,164,319	14,900,414
22	Total in Service (18 thru 21)	5,303,859,450	3,392,169,848
23	Leased to Others		
24	Depreciation	0	
25	Amortization and Depletion	0	
26	Total Leased to Others (24 & 25)	0	0
27	Held for Future Use		
28	Depreciation	33,615	5,295
29	Amortization	0	
30	Total Held for Future Use (28 & 29)	33,615	5,295
31	Abandonment of Leases (Natural Gas)	0	
32	Amort of Plant Aquisition Adj.	48,532	
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,303,941,597	3,392,175,143

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
2,768,898,094				451,314,554	3
13,678,654				6,848,932	4
					5
					6
					7
2,782,576,748	0	0	0	458,163,486	8
					9
561,202				182,262	10
20,247,307				21,968,703	11
283,275					12
2,803,668,532	0	0	0	480,314,451	13
1,666,213,924				245,552,530	14
1,137,454,608	0	0	0	234,761,921	15
					16
					17
1,639,470,961				133,628,674	18
8,356,420					19
3,969,642					20
14,340,050				111,923,855	21
1,666,137,073	0	0	0	245,552,529	22
					23
					24
					25
0	0	0	0	0	26
					27
28,320					28
					29
28,320	0	0	0	0	30
					31
48,532					32
1,666,213,925	0	0	0	245,552,529	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		34,288,543
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	45,574	
9	In Reactor (120.3)	104,855,872	29,403,721
10	SUBTOTAL (Total 8 & 9)	104,901,446	
11	Spent Nuclear Fuel (120.4)	211,180,178	33,670,201
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	325,469,620	15,126,342
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	-9,387,996	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		526,232
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)	(f)	
			1
	29,630,799	4,657,744	2
			3
			4
			5
		4,657,744	6
			7
		45,574	8
	33,670,201	100,589,392	9
		100,634,966	10
		244,850,379	11
			12
		340,595,962	13
		9,547,127	14
			15
			16
			17
	526,232		18
			19
			20
			21
			22

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Schedule Page: 202 Line No.: 2 Column: e

$29,104,567 of nuclear fuel in process moved to nuclear fuel in reactor account 120.357.
$526,232 transferred to nuclear materials held for sale account 157.100.

Schedule Page: 202 Line No.: 9 Column: e

$33,670,201 of nuclear fuel in the reactor was removed during the refueling outage and recorded in account 120.452 as spent nuclear fuel.

Schedule Page: 202 Line No.: 18 Column: e

Sales Proceeds	$780,930.52
Gain transferred to Fuel Expense	($254,698.55)
Cost of fuel sold	$526,231.97

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	95,859	
3	(302) Franchises and Consents	18,735,085	2,621
4	(303) Miscellaneous Intangible Plant	8,993,214	1,852,482
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	27,824,158	1,855,103
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,660,116	
9	(311) Structures and Improvements	390,103,323	1,132,954
10	(312) Boiler Plant Equipment	1,082,253,826	75,820,865
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	284,785,955	4,736,427
13	(315) Accessory Electric Equipment	123,270,497	109,324
14	(316) Misc. Power Plant Equipment	21,598,099	420,139
15	(317) Asset Retirement Costs for Steam Production	3,952,493	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,910,624,309	82,219,709
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	2,735,105	
19	(321) Structures and Improvements	176,628,596	11,444,674
20	(322) Reactor Plant Equipment	421,157,035	14,654,100
21	(323) Turbogenerator Units	127,663,745	915,621
22	(324) Accessory Electric Equipment	48,416,346	2,959,229
23	(325) Misc. Power Plant Equipment	29,511,251	1,026,722
24	(326) Asset Retirement Costs for Nuclear Production	26,791,344	59,652,127
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	832,903,422	90,652,473
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	5,056,951	
28	(331) Structures and Improvements	21,255,522	570,360
29	(332) Reservoirs, Dams, and Waterways	145,918,874	431,127
30	(333) Water Wheels, Turbines, and Generators	46,864,074	-112,850
31	(334) Accessory Electric Equipment	8,920,125	-48,616
32	(335) Misc. Power PLant Equipment	3,700,852	20,580
33	(336) Roads, Railroads, and Bridges	1,599,554	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	233,315,952	860,601
36	D. Other Production Plant		
37	(340) Land and Land Rights	132,259	
38	(341) Structures and Improvements	759,309	
39	(342) Fuel Holders, Products, and Accessories	400,587	
40	(343) Prime Movers		
41	(344) Generators	35,171,342	6,493,302
42	(345) Accessory Electric Equipment	2,478,065	
43	(346) Misc. Power Plant Equipment	510,016	18,550

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

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 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.

7. 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, 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.

8. 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 requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, 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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			95,859		2
4,836			18,732,870		3
486,625			10,359,071		4
491,461			29,187,800		5
					6
					7
			4,660,116		8
116,549		519,781	391,639,509		9
6,248,520	-324	-578,549	1,151,247,298		10
					11
4,801,375		82,185	284,803,192		12
100,261		134,197	123,413,757		13
399,642	-24,999	-210,040	21,383,557		14
			3,952,493		15
11,666,347	-25,323	-52,426	1,981,099,922		16
					17
61,415			2,673,690		18
		-13,139	188,060,131		19
178,631			435,632,504		20
			128,579,366		21
			51,375,575		22
81,905		-83,723	30,372,345		23
			86,443,471		24
321,951		-96,862	923,137,082		25
					26
44,511			5,012,440		27
2,993		171,965	21,994,854		28
330,352		-146,447	145,873,202		29
63,338		229,488	46,917,374		30
121,115		-415,244	8,335,150		31
44,822	-7,767	118,900	3,787,743		32
			1,599,554		33
					34
607,131	-7,767	-41,338	233,520,317		35
					36
			132,259		37
			759,309		38
			400,587		39
					40
			41,664,644		41
4,299			2,473,766		42
			528,566		43

Name of Respondent Consumers Energy Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	39,451,578	6,511,852
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,016,295,261	180,244,635
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights		21,434
49	(352) Structures and Improvements		
50	(353) Station Equipment		
51	(354) Towers and Fixtures		
52	(355) Poles and Fixtures		
53	(356) Overhead Conductors and Devices		44,215
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)		65,649
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	116,234,920	3,898,990
61	(361) Structures and Improvements	37,359,848	6,559,877
62	(362) Station Equipment	567,721,890	36,012,172
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	714,596,496	39,131,525
65	(365) Overhead Conductors and Devices	663,223,432	41,628,735
66	(366) Underground Conduit	54,964,301	3,976,713
67	(367) Underground Conductors and Devices	353,740,651	14,028,707
68	(368) Line Transformers	563,423,706	22,770,997
69	(369) Services	478,625,810	16,402,844
70	(370) Meters	144,429,828	10,085,359
71	(371) Installations on Customer Premises	6,607,953	232,984
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	78,564,943	3,854,907
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,779,493,778	198,583,810
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	2,813,531	
78	(390) Structures and Improvements	41,183,587	334,730
79	(391) Office Furniture and Equipment	13,487,204	1,335,339
80	(392) Transportation Equipment	8,409,338	15,778
81	(393) Stores Equipment	84,942	
82	(394) Tools, Shop and Garage Equipment	5,054,311	251,897
83	(395) Laboratory Equipment	4,483,958	203,440
84	(396) Power Operated Equipment	1,906,045	27,569
85	(397) Communication Equipment	35,615,004	35,707
86	(398) Miscellaneous Equipment	1,345,454	20,225
87	SUBTOTAL (Enter Total of lines 77 thru 86)	114,383,374	2,224,685
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	114,383,374	2,224,685
91	TOTAL (Accounts 101 and 106)	6,937,996,571	382,973,882
92	(102) Electric Plant Purchased (See Instr. 8)		
93	(Less) (102) Electric Plant Sold (See Instr. 8)	-55,933	
94	(103) Experimental Plant Unclassified		
95	TOTAL Electric Plant in Service (Enter Total of lines 91 thru 94)	6,938,052,504	382,973,882

Name of Respondent Consumers Energy Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					44
4,299			45,959,131		45
12,599,728	-33,090	-190,626	3,183,716,452		46
					47
		-21,434			48
					49
					50
					51
					52
		-44,215			53
					54
					55
					56
					57
		-65,649			58
					59
553,716		-2,016,858	117,563,336		60
293,616		-1,187,000	42,439,109		61
6,739,459		1,351,561	598,346,164		62
					63
4,390,625	15,673	-88,346	749,264,723		64
3,445,953	9,509	-37,733	701,377,990		65
150,307		27,974	58,818,681		66
517,310	64,847	102,782	367,419,677		67
3,591,391			582,603,312		68
1,443,998			493,584,656		69
3,587,956			150,927,231		70
127,388			6,713,549		71
					72
630,613			81,789,237		73
					74
25,472,332	90,029	-1,847,620	3,950,847,665		75
					76
1,954			2,811,577		77
			41,518,317		78
2,401,333		1,261,233	13,682,443		79
1,449,579		-755,334	6,220,203		80
			84,942		81
			5,306,208		82
			4,687,398		83
		-175,369	1,758,245		84
	-318	-33,652	35,616,741		85
			1,365,679		86
3,852,866	-318	296,878	113,051,753		87
					88
					89
3,852,866	-318	296,878	113,051,753		90
42,416,387	56,621	-1,807,017	7,276,803,670		91
					92
			-55,933		93
					94
42,416,387	56,621	-1,807,017	7,276,859,603		95

FOOTNOTE DATA

Schedule Page: 204 Line No.: 93 Column: b

Sale METC to TRANSELEC - 2001

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3	Distribution Plant:			
4	Barry-Delhi-Looking Glass	12/31/67	12/31/08	365,494
5	G Rapids-Kal-BattCr & Buck Cr	02/26/01	12/31/05	639,281
6	Quanicassee-Gary Road	11/30/75	12/31/10	1,804,619
7	Millington-Blackfoot	11/30/75	12/31/08	1,716,077
8	Tittabawassee-Thetford-Kenowa/Claremont-Lawndale	11/30/75	12/31/10	323,806
9	Gary Road-Sprague Creek	12/31/78	12/31/08	1,231,455
10	Pompeii	06/30/79	12/31/06	562,409
11	Sprague Creek-Zeeland	12/31/80	12/31/12	2,091,647
12	Vrooman-Moore Rd	12/31/82	12/31/07	390,614
13	Spraure Creek-Goss	12/31/82	12/31/05	1,064,367
14	Harvey-Spaulding	12/31/85	12/31/05	483,971
15	Battle Creek-Batavia	11/30/93	12/31/05	5,794,661
16	Lenawee	12/31/04	12/31/08	954,697
17				
18	Distribution Plant			
19	74 Properties	various	various	3,848,098
20				
21	Other Property:			
22	Distribution Plant - 3 Properties	various	various	93,605
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
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42				
43				
44				
45				
46				
47	Total			21,364,801

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED - ELECTRIC (Accounts 106 and 107)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed Construction Not Classified- Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 204-211, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development (See Account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress- Electric (Account 107) (b)	Completed Construction Not Classified- Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	Energy Production Plant - Nuclear Additions/Improvements	$35,596,041		$27,405,000
2	Energy Production Plant - Fossil/Hydro Additions/Improvements	$26,786,158		$41,565,000
3	Energy Production Plant - Clear Air Act Amendment	$186,012,975		$68,476,000
4	Distribution Substations System and Improvements	$7,205,658		$20,221,000
5	Distribution Substations/Lines - Obsolescence and Failure	$5,335,116		$7,086,000
6	Distribution Substations and Connecting Power Lines	$1,863,723		$4,308,000
7	Distribution Substations	$15,500,335		$23,456,000
8	Distribution Systems - Additions and Improvements	$6,531,927		$99,022,000
9	Land and Landrights - Facilities	$5,801,008		$1,772,000
10	Office and Service Buildings	$2,313,939		$3,279,000
11	Tools and Equipment	$182,748		$640,000
12	Computer Equipment	$968,128		$2,231,000
13	Capitalized Software Projects	$1,023,163		$799,000
14	Electric Substations and Connecting Power Lines	($240,339)		$1,166,000
15	Telecommunications Equipment	$2,081,161		$1,049,000
16	Transportation Equipment	$416,595		$355,000
17	Mechanical Equipment	$109,038		$42,000
18	Minor Projects	$877,198		$7,931,000
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	TOTAL	$298,364,572	$0	$310,803,000

CONSTRUCTION OVERHEADS-ELECTRIC

1. List in column (a) the kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items.
2. On page 218 furnish information concerning construction overheads.
3. A respondent should not report "none" to this page if no overhead apportionments are made, but rather should explain on page 218 the accounting procedures employed and the amounts of engineering, supervision and administrative costs, etc., which are directly charged to construction.
4. Enter on this page engineering, supervision, adminstrative, and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs.

Line No.	Description of Overhead (a)	Total Amount Charged for the Year (b)
1	Engineering and Supervision	$58,031,563
2	Administrative and General	24,895,699
3		
4		
5		
6		
7		
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11		
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37		
38		
39		
40	TOTAL	$82,927,262

GENERAL DESCRIPTION OF CONSTRUCTION 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, if those differ from the overall rate of return authorized by the Michigan Public Service Commission.

ENGINEERING AND SUPERVISION

Includes (1) charges by outside engineering companies and (2) the actual time and expenses of Company employees devoted to the design, planning and supervision of construction jobs. Costs were derived by direct charges from payrolls, invoices, vouchers, etc. On major construction jobs these costs were charged directly to the construction job involved. On minor construction jobs these costs were accumulated in a construction clearing account which was distributed pro rata over all minor construction jobs, except land and landrights, general equipment and nuclear fuel, on the basis of direct labor and material charges.

ADMINISTRATIVE AND GENERAL

An examination was made of the various expenses classified as administration and general to determine those containing substantial amounts applicable to construction expenditures. Costs were allocated to construction on the basis of (1) time spent on construction-related activities after obtaining information from the employee having firsthand knowledge of the expense or work performed and (2) by direct charges from payrolls, invoices, vouchers, etc. The total so allocated was distributed prorata over all construction jobs except nuclear fuel and general equipment on the basis of direct company labor and engineering and supervision costs.

Pension expenses and payroll taxes were allocated directly, based on payroll charges, to the various work orders.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

An allowance is applied on all construction where the period of construction is greater than six months and the cost is expected to exceed $50,000 (exclusive of the allowance). It is computed monthly and based on the accumulated balance of total construction costs. The allowance is charged during the actual period of construction, starting from the date that field construction begins and terminating when the facility is tested and placed in or is ready for service.

INSURANCE

Insurance costs have been charged directly to the major construction jobs to which they apply.

PROPERTY TAXES

Property taxes are capitalized on projects where the period of construction is greater than six months and the project is estimated to cost $500,000 or more. The capitalized taxes on major generating plants are actual taxes paid. Taxes capitalized on other than the major generating jobs are computed by estimating the equalized taxable value and multiplying this by the Company average millage rate to determine the tax to be capitalized for the year.

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC 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 electric plant in service, pages 204-207A, column (d), excluding retirements of non-depreciable property.
3. Accounts 108 and 110 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 cost included in retirement work in process 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)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	3,236,045,332	3,236,040,037	5,295	-
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	163,271,700	163,271,700	-	-
4	(403.1) Decommissioning Expense	6,108,218	6,108,218	-	-
5	(413) Exp. of Elec. Plt. Leas. to Others	0	0	-	-
6	Transportation Expenses-Clearing	242,399	242,399	-	-
7	Other Clearing Accounts	28,354,000	28,354,000	-	-
8	Other Accounts (Specify):				
9	(403.2) Gas Depreciation Expense	0	0	-	-
10	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 9)	197,976,317	197,976,317	-	-
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	39,734,266	39,734,266	-	-
13	Cost of Removal	59,922,924	59,922,924	-	-
14	Salvage (Credit)	2,382,361	2,382,361	-	-
15	TOTAL Net Charges for Plant Ret. (Enter Total of lines 12 thru 14)	102,039,551	102,039,551	-	-
16	Net Earnings of Decommissioning Funds	25,209,298	25,209,298	-	-
17	Other Debit or Credit Items (Describe)				
18	Other Items Applied	20,083,333	20,083,333	-	-
19	Balance End of Year (Enter Total of lines 1, 10, 15, 16, 17, and 18)	3,377,274,729	3,377,269,434	5,295	-
	Section B. Balances at End of Year According to Functional Classifications				
20	Steam Production	820,844,465	820,844,223	242	-
21	Nuclear Production - Depreciation	737,475,914	737,475,914	-	-
22	Nuclear Production - Decommissioning	103,624,179	103,624,179	-	-
23	Hydraulic Production - Conventional	14,916,456	14,916,456	-	-
24	Hydraulic Production - Pumped Storage	102,452,431	102,452,431	-	-
25	Other Production	39,457,722	39,457,722	-	-
26	Transmission	0	0	-	-
27	Distribution	1,497,355,349	1,497,350,296	5,053	-
28	General	61,148,213	61,148,213	-	-
29	TOTAL (Enter Total of Lines 20 thru 28)	3,377,274,729	3,377,269,434	5,295	-

2. Electric Plant in Service Retirements-

Page 207, Line 91, Col (d)	42,416,387
Nondepreciable Property	(1,153,057)
Other Adjustments	(1,529,064)
Book Cost of Plant Retired-Line 12, Col (c)	39,734,266

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NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.
5. Minor items (5% of the Balance at the End of the Year for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service, or (2) other nonutility property.

Line No.	Description and Location (a)	Year Trans-ferred to Nonutility	Balance at Beginning of Year (b)	Purchases, Sales, Transfers, etc. (c)	Balance at End of Year (d)
1	LAND PREVIOUSLY DEVOTED TO PUBLIC SERVICE				
2	Alpena County - Alpena Township				
3	1 parcel of land in Section 18	1988	182,083	-	182,083
4	Bay County - Hampton Township				
5	1 parcel of land in Section 15 (1)	1982	111,794	-	111,794
6	Oakland County - Springfield Township				
7	1 Parcel of Land in Section 7	1990	123,678	-	123,678
8	St Clair County - Cosco Township				
9	1 parcel of land in Section 27	1984	152,704	-	152,704
10	1 parcel of land in Section 29	1988	121,301	-	121,301
11	LAND LEASED TO OTHERS				
12	Midland County				
13	80 parcels of Land**	1987	6,130,593	-	6,130,593
14	Lessees: Midland Cogeneration Venture				
15	Limited Partnership (Associated Company)				
16	OTHER NONUTILITY PROPERTY				
17	MCV Electric Transmission Facilities	1990	318,362	-	318,362
18	MCV Related Line & Sub	1991	1,735,146	-	1,735,146
19	Various Residential Electric Homeowners & Region				
20	Storerooms - Wholehouse Surge Suppressors	1993	285,458		285,458
21					
22	Minor Items Previously Devoted to Public Service		5,906,102	(60,150)	5,845,952
23	Minor Items - Other Nonutility Property		-	-	-
24	TOTAL		15,067,221	(60,150)	15,007,071

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF NONUTILITY PROPERTY (Account 122)

Report below the information called for concerning depreciation and amortization of nonutility property.

Line No.	Item (A)	Amount (b)
1	Balance, Beginning of Year	917,308
2	Accruals for Year, Charged to	
3	(417) Income from Nonutility Operations	0
4	(418) Nonoperating Rental Income	0
5	Other Accounts (Specify): (108) Transfer of Reserves & Work in Progress Changes and Closings	703,044
6		
7	TOTAL Accruals for Year (Enter Total of lines 3 thru 6)	703,044
8	Net Charges for Plant Retired	
9	Book Cost of Plant Retired	0
10	Cost of Removal	0
11	Salvage (Credit)	0
12	TOTAL Net Charges (Enter Total of lines 9 thru 11)	0
13	Other Debit or Credit Items (Describe):	
14		0
15	Balance, End of Year	1,620,352

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 user, date aquired 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 reaquired 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 an open account. Each note should be listed giving date of issuance, maturity date,

Line No.	Description of Investment (a)	Book Cost at Beginning of Year* (b)	Purchases or Additions During Year (c)
1	ACCOUNT 123 (Excluding 123.1)		
2			
3	CMS Energy Common Stock	10,410,638	0
4	FAS 115 CMS Stock Adjustment (1)	9,702,432	4,556,130
5			
6	Total Account 123 (Excluding 123.1)	20,113,070	4,556,130
7			
8	ACCOUNT 124		
9	Contracts Receivable	556,894	9,275
10	Detroit Investment Fund	1,500,000	0
11	Commercial Loans	73,215	53,991
12	Customer Loans	56,334	107,873
13	Aegis Insurance Recovery - MGP	3,466,640	182,866
14	Alpena Power Liquidated Damages Note	625,951	46,623
15	Miscellaneous	407,863	549,161
16			
17	Total Account 124	6,686,897	949,789
18			
19			
20	ACCOUNT 136		
21			
22			
23	Other Temporary Cash Investments	0	4,008,790,405
24	Adrian Energy Perform Escrow	255,778	9,879
25	Wurstsmith AFB Escrow	516,171	1,288
26	North American Escrow	670,289	15,362
27			
28	Total Account 136	1,442,238	4,008,816,934
29			
30			
31	(1) Includes the unrealized investment gain from book value as required under SFAS 115.		
32			

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

and specify 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 adjustments 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* (f)	Revenues for Year (g)	Gain or (Loss) From Investment Disposed of (h)	Line No.
					1
					2
0	0	10,410,638	0	0	3
0	0	14,258,562	0	0	4
					5
0	0	24,669,200	0	0	6
					7
					8
38,083	0	528,086	0	0	9
355,450	0	1,144,550	0	0	10
90,043	0	37,163	0	0	11
113,610	0	50,597	0	0	12
0	0	3,649,506	0	0	13
346,000	0	326,574	0	0	14
41,312	0	915,712	0	0	15
					16
984,498	0	6,652,188	0	0	17
					18
					19
					20
					21
					22
3,976,716,248	0	32,074,158	0	0	23
265,658	0	0	0	0	24
517,458.51	0	0	0	0	25
685,651	0	0	0	0	26
					27
3,978,185,015	0	32,074,158	0	0	28
					29
					30
					31
					32

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	ES SERVICES COMPANY			
2	Investment in Common Stock	05/31/89		641,000
3	Equity in Undistributed Earnings			-34,239
4				
5	SUBTOTAL			606,761
6				
7				
8	CMS ENGINEERING CO.			
9	Investment in Common Stock	04/30/94		81,001
10	Equity in Undistributed Earnings			133,076
11				
12	SUBTOTAL			214,077
13				
14				
15	CMS MIDLAND, INC.			
16	Investment in Common Stock	12/31/94		156,332,688
17	Equity in Undistributed Earnings			195,823,071
18	Note payable	12/31/97	12/31/05	10,000,000
19				
20	SUBTOTAL			362,155,759
21				
22				
23	CMS MIDLAND HOLDINGS COMPANY			
24	Investment in Common Stock	12/31/94		31,326,796
25	Equity in Undistributed Earnings			33,194,431
26				
27	SUBTOTAL			64,521,227
28				
29				
30	MEC DEVELOPMENT CORP.			
31	Investment in Common Stock	12/31/94		6,391
32	Equity in Undistributed Earnings			-5,411
33				
34	SUBTOTAL			980
35				
36				
37	CONSUMERS POWER COMPANY FINANCING I			
38	Investment in Common Stock	01/02/96		3,092,800
39	Equity in Undistributed Earnings			
40	SUBTOTAL			3,092,800
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	668,037,531

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. 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.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. 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 difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		641,000		2
-52,364		-86,603		3
				4
-52,364		554,397		5
				6
				7
				8
		81,001		9
-18,532		114,544		10
				11
-18,532		195,545		12
				13
				14
				15
		167,326,989		16
-8,206,392		187,616,679		17
		10,000,000		18
				19
-8,206,392		364,943,668		20
				21
				22
				23
		42,642,117		24
9,220,460		42,414,893		25
				26
9,220,460		85,057,010		27
				28
				29
		6,391		30
		-5,411		31
				32
				33
		980		34
				35
				36
				37
		3,092,800		38
258,558	-258,558			39
258,558	-258,558	3,092,800		40
				41
2,128,290	-1,411,453	761,190,933		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2	CONSUMERS ENERGY COMPANY FINANCING II	09/30/97		
3	Investment in Common Stock			3,711,350
4	Equity in Undistributed Earnings			
5				
6	SUBTOTAL			3,711,350
7				
8	CONSUMERS ENERGY COMPANY FINANCING III			
9	Investment in Common Stock	11/30/99		5,412,375
10	Equity in Undistributed Earnings			
11	SUBTOTAL			5,412,375
12				
13				
14	CONSUMERS FUNDING, LLC.			
15	Investment in Common Stock	10/11/00		2,342,960
16				
17	SUBTOTAL			2,342,960
18				
19				
20	CONSUMERS ENERGY COMPANY FINANCING IV			
21	Investment in Common Stock	10/12/99		3,866,000
22	Equity in Undistributed Earnings			
23	SUBTOTAL			3,866,000
24				
25				
26	Consumers Nuclear Services, LLC.			
27	Investment in Common Stock	5/23/01		2,340,548
28	Equity in Undistributed Retain Earnings			21,006
29				
30	SUBTOTAL			2,361,554
31				
32				
33	CONSUMERS RECEIVABLES FUNDING II			
34	Investment in Common Stock	4/24/03		219,608,785
35	Equity in Undistributed Earnings			
36				
37	SUBTOTAL			219,608,785
38				
39				
40	CONSUMERS CAMPUS HOLDINGS, LLC			
41	Investment in Common Stock	4/23/01		147,670
42	Total Cost of Account 123.1 $ 0		TOTAL	668,037,531

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. 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.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. 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 difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
		3,711,350		3
304,331	-304,311			4
				5
304,331	-304,311	3,711,350		6
				7
				8
		5,412,375		9
500,645	-500,645			10
500,645	-500,645	5,412,375		11
				12
				13
				14
		2,342,960		15
				16
		2,342,960		17
				18
				19
				20
		3,866,000		21
347,940	-347,939			22
347,940	-347,939	3,866,000		23
				24
				25
				26
		3,890,446		27
-216,551		-195,545		28
				29
-216,551		3,694,901		30
				31
				32
				33
		288,160,838		34
				35
				36
		288,160,838		37
				38
				39
				40
		147,670		41
2,128,290	-1,411,453	761,190,933		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Equity in Undistributed Earnings			-4,767
2				
3	SUBTOTAL			142,903
4				
5				
6	CONSUMERS SAGINAW INVESTMENTS, LLC	9/23/04		
7	Investment in Common Stock			
8				
9	SUBTOTAL			
10				
11				
12				
13				
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36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	668,037,531

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. 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.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. 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 difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
-9,805		-14,571		1
				2
-9,805		133,099		3
				4
				5
				6
		25,010		7
				8
		25,010		9
				10
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				40
				41
2,128,290	-1,411,453	761,190,933		42

NOTES AND ACCOUNTS RECEIVABLE - Summary for Balance Sheet

Show separately by footnote the total amount of notes and accounts receivable from directors, officers, and employees included in Notes Receivable (Account 141) and Other Accounts Receivable (Account 143).

Line No.	Accounts (a)	Balance Beginning of Year (b)	Balance End of Year (c)
1	Notes Receivable (Account 141)	0	5,942,160
2	Customer Accounts Receivable (Account 142)	14,158,341	9,529,496
3	Other Accounts Receivable (Account 143) (Disclose any capital stock subscriptions received)	29,806,056	36,451,751
4	Total	43,964,397	51,923,407
5	Less: Accumulated Provision for Uncollectible Accounts - Cr. (Account 144)	8,451,343	9,909,700
6	Total, Less Accumulated Provision for Uncollectible Accounts	35,513,054	42,013,707
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS - CR. (Account 144)

1. Report below the information called for concerning this accumulated provision.
2. Explain any important adjustments of subaccounts.
3. Entries with respect to officers and employees shall not include items for utility services.

Line No.	Item (a)		Utility Customers (b)	Merchandise, Jobbing and Contract Work (c)	Officers and Employees (d)	Other (e)	Total (f)
1	Balance Beginning of Year		8,299,745	0	0	151,598	8,451,343
2	Prov for Uncollectibles for Current Year		3,110,936	0	0	61,745	3,172,681
3	Accounts Written Off	(1)	(841,694)	0	0	(345,899)	(1,187,593)
4	Collection of Accounts Written Off	(1)	698,919	0	0	272,677	971,596
5	People Care		(1,498,327)	0	0	0	(1,498,327)
				0	0	0	
6	Balance End of Year		9,769,579	0	0	140,121	9,909,700
7							
8							
9	(1) Accounts written off and collection of accounts written off are for Appliance Service Plans						
10	In addition, a net amount of $17,149,302 ($16,683,342 Residential and Commercial)						
11	uncollectible accounts was charged to expense (Account 904)						
12	and creditied to accounts receivable during the year.						
13							
14							
15							

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

1. Report particulars of notes and accounts receivable from associated companies* at end of year.
2. Provide separate headings and totals for Accounts 145, Notes Receivable From Associated Companies, and 146, Accounts Receivable from Associated Companies, in addition to a total for the combined accounts.
3. For notes receivable, list each note separately and state purpose for which received. Show also in column (a) date of note, date of maturity and interest rate.
4. If any note was received in satisfaction of an open account, state the period covered by such open account.
5. Include in column (f) interest recorded as income during the year including interest on accounts and notes held held any time during the year.
6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

*NOTE: "Associated companies" means companies or persons that, directly or indirectly, through one or more intermediaries, control or are controlled by, or are under common control with, the accounting company. This includes related parties. "Control" (including the terms "controlling", "controlled by", and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a company, whether such power is exercised through one or more intermediary companies, or alone, or in conjunction with, or pursuant to an agreement, and whether such power is established through a majority or minority ownership or voting of securities, common directors, officers, or stockholders, voting trusts, holding trusts, associated companies, contract or any other direct or indirect means.

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year Debits (c)	Totals for Year Credits (d)	Balance End of Year (e)	Interest for Year (f)
1	ACCOUNT 145					
2	NOTES RECEIVABLE FROM ASSOCIATED COMPANIES					
3						
4						
5	Total Account 145	0	0	0	0	0
6						
7	ACCOUNT 146					
8	ACCOUNTS RECEIVABLE FROM ASSOCIATED COMPANIES					
9	Associated Co Employee Miscellaneous Deductions	477,285	2,157,800	2,635,085	0	0
10	CMS Antrim Gas LLC	42,696	223,103	229,076	36,723	835
11	CMS Bay Area Pipeline LLC	1,614	52,097	18,553	35,158	155
12	CMS Capital LLC	411	1,278,113	1,206,718	71,806	6,436
13	CMS Distributed Power LLC	4,098	16	4,114	0	16
14	CMS Electric & Gas LLC	11,929	33,001	40,737	4,193	270
15	CMS Energy Corporation	1,049,496	67,460,357	59,053,411	9,456,442	50,106
16	CMS Energy Resource Management Company	404,716	4,546,612	4,256,636	694,692	7,950
17	CMS Engineering Company	932	22,719	19,946	3,705	145
18	CMS Enterprises Company	793,027	12,407,475	11,847,563	1,352,939	41,891
19	CMS Enterprises N. American Division	321	0	321	0	0
20	CMS Gas Transmission Company	351,060	1,973,770	2,069,927	254,903	7,091
21	CMS Generation Company	281,835	2,437,859	2,384,996	334,698	14,287
22	CMS Generation Filer City Operating Company	28,585	580,715	561,894	47,406	1,182
23	CMS Generation Genesee Company	135,977	26,672	160,862	1,787	11
24	CMS Generation Michigan Power LLC	0	15,615	15,615	0	0
25	CMS Generation Operating Company	61,526	745,838	707,117	100,247	2,747
26	CMS Generation Operating Company II Inc	27,342	396,936	364,549	59,729	1,494
27	CMS Grands Lacs LLC	8,819	33,252	40,431	1,640	97
28	CMS International Operating Company	9,410	63,294	62,214	10,490	388
29	CMS International Ventures LLC	14,245	600,523	595,810	18,958	3,523
30	CMS Land Company	45,770	795,320	327,943	513,147	1,687
31	CMS Marysville Gas Liquids Company	121,967	1,237	123,204	0	0
32	CMS Midland Holdings Company	2,631	21,438	20,377	3,692	126
33	CMS Midland, Inc	3,986	33,889	33,282	4,593	204
34	CMS Resource Development Company	17,468	151,146	155,566	13,048	1,004
35	CMS Texas LLC	4,540	51,562	51,646	4,456	319
36	Consumers Campus Holdings LLC	1,816	15,077	14,531	2,362	92
37	Consumers Energy Company Financing II	0	228,248	228,248	0	0
38	Consumers Energy Company Financing III	0	375,484	375,484	0	0

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146) (Continued)

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year Debits (c)	Totals for Year Credits (d)	Balance End of Year (e)	Interest for Year (f)
39	ACCOUNT 146 (Continued)					
40	Consumers Energy Company Financing IV	0	260,955	260,955	0	0
41	Consumers EnergyGuard Services, Inc	1,122	221	1,343	0	0
42	Consumers Funding LLC	299,696	1,201,771	1,188,292	313,175	0
43	Consumers Nuclear Services LLC	29,330	154,620	158,969	24,981	1,048
44	Consumers Power Company Financing I	0	193,919	193,919	0	0
45	Dearborn Generation Operating LLC	91,848	539,386	549,337	81,897	3,271
46	Dearborn Industrial Generation Plant	34,245	13,554	47,500	299	0
47	EnerBank U.S.A.	98,520	157,137	255,657	0	2,882
48	ES Services Company	106,545	1,922,173	1,719,257	309,461	10,442
49	Jackson Pipeline Company	2,059	96,993	90,781	8,271	0
50	Jorf Lasfar Plant	91,363	0	91,363	0	0
51	MEC Development Corporation	647	4,177	4,124	700	25
52	Midland Cogeneration Venture	221,899	12,941,334	12,357,092	806,141	646
53						
54						
55						
56						
57						
58						
59						
60						
61						
62						
63						
64						
65	Dividends Receivable of					
66	CMS Energy Corporation	0	0	0	0	-
67						
68	Total Account 146	4,880,776	114,215,408	104,524,445	14,571,739	160,370
69						
70						
71	It should be noted that column C may					
72	reflect activity in the accounts which					
73	includes estimates.					
74						
75						
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86						
87						
88						
89						
90						
91						
92						
93						
94						
95				TOTAL	14,571,739	160,370

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	41,031,275	48,732,160	
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	24,895,069	17,309,417	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	36,006,970	37,291,922	
8	Transmission Plant (Estimated)	244,587	881,459	
9	Distribution Plant (Estimated)	9,106,285	11,510,329	
10	Assigned to - Other (provide details in footnote)			
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	70,252,911	66,993,127	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
15	Stores Expense Undistributed (Account 163)	-560,136		
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	110,724,050	115,725,287	

PRODUCTION FUEL AND OIL STOCKS (Included in Account 151)

1. Report below the information called for concerning production fuel and oil stock.
2. Show quantities in tons of 2000 lb. Barrels or Mcf., whichever unit of quantity is applicable.
3. Each kind of coal or oil should be shown separately.
4. If the respondent obtained any of its fuel from its own coal mines or gas lands or leases or from affiliated companies, a statement should be submitted showing the quantity of such fuel so obtained, the quantity used and quantity on hand, and cost of the fuel classified as to the nature of the costs and expenses incurred with appropriate adjustment for the inventories at beginning and end of year.

Line No.	Item (a)	Total Cost (b)	KINDS OF FUEL AND OIL — Coal Stocks Quantity (c)	Coal Stocks Cost (d)
1	On hand beginning of year	41,031,275	996,483.3	28,308,709
2	Received during year	298,523,226	10,002,333.7	279,370,290
3	TOTAL	339,554,501	10,998,817.0	307,678,999
4	Used during year (specify department)			
5	Electric Department Generating Plants	280,929,176	9,663,118.6	265,894,884
6	Inventory Adjustments	-	(58,354.1)	-
7				
8				
9				
10				
11				
12				
13				
14				
15	Sold or transferred	6,180,079	192,877.6	5,525,507
16	TOTAL DISPOSED OF	290,822,341	9,797,642.1	271,420,391
17	BALANCE END OF YEAR	48,732,160	1,201,174.9	36,258,608

PRODUCTION FUEL AND OIL STOCKS (Included in Account 151) (Continued)

KINDS OF FUEL AND OIL (continued)

Steam Generation Gas Stocks		Oil Stocks		Internal Combustion Oil Stocks		
Quantity (e)	Cost (f)	Quantity (g)	Cost (h)	Quantity (i)	Cost (j)	Line No.
231,738.0	1,248,184	466,067.1	11,274,477	6,362.7	199,905	1
981,594.0	5,964,762	401,067.4	13,188,174	-	-	2
1,213,332.0	7,212,946	867,134.5	24,462,651	6,362.7	199,905	3
						4
833,435.0	4,915,327	521,198.4	14,477,496	297.8	9,127	5
-	-	(750.2)	-	(91.7)	-	6
						7
						8
						9
						10
						11
						12
						13
						14
0.0	-	-	-	-	-	15
833,435.0	4,915,327	520,448.2	14,477,496	206.1	9,127	16
379,897.0	2,297,619	346,686.3	9,985,155	6,156.6	190,778	17

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2005 No. (d)	2005 Amt. (e)
1	Balance-Beginning of Year	161,376.00	10,246,985	97,843.00	11,190,260
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	9,618.00		7,412.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	SO2				
10	NOx				
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	82,058.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	SO2	33,261.00			
23	NOx				
24					
25	Emissions	8,192.00	7,011,847		
26			260,073		
27					
28	Total	41,453.00	7,271,920		
29	Balance-End of Year	47,483.00	2,975,065	105,255.00	11,190,260
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	1,357.60		1,357.60	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	1,357.60			
40	Balance-End of Year			1,357.60	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		369,110		
45	Gains		369,110		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2006		2007		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
95,693.00	277,500	95,693.00	277,500	2,427,840.00	277,500	2,878,445.00	22,269,745	1
								2
								3
7,412.00		7,612.00		108,627.00		140,681.00		4
								5
								6
								7
								8
				33,261.00		33,261.00		9
450.00	198,750	400.00	198,750	200.00	198,750	1,050.00	596,250	10
								11
								12
								13
								14
450.00	198,750	400.00	198,750	33,461.00	198,750	34,311.00	596,250	15
								16
								17
						82,058.00		18
								19
								20
								21
						33,261.00		22
								23
								24
						8,192.00	7,011,847	25
							260,073	26
								27
						41,453.00	7,271,920	28
103,555.00	476,250	103,705.00	476,250	2,569,928.00	476,250	2,929,926.00	15,594,075	29
								30
								31
								32
								33
								34
								35
1,353.20		1,358.00		66,143.90		71,570.30		36
				2,699.00		2,699.00		37
								38
				1,349.50		2,707.10		39
1,353.20		1,358.00		67,493.40		71,562.20		40
								41
								42
								43
					172,734		541,844	44
					172,734		541,844	45
								46

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Schedule Page: 228 Line No.: 1 Column: b

Includes: SO2 balance of 159,326 and NOx balance of 2,050.

Schedule Page: 228 Line No.: 1 Column: c

$10,246,985 represents cost of 2,050 NOx Allowances for vintage year 2004.

Schedule Page: 228 Line No.: 1 Column: d

Includes: SO2 balance of 95,443 and NOx balance of 2,400.

Schedule Page: 228 Line No.: 1 Column: e

$11,190,260 represents cost of 2,400 NOx Allowances for vintage year 2005.

Schedule Page: 228 Line No.: 1 Column: f

Includes: SO2 balance of 95,443 and NOx balance of 250.

Schedule Page: 228 Line No.: 1 Column: g

$277,500 represents cost of 250 NOx Allowances for vintage year 2006.

Schedule Page: 228 Line No.: 1 Column: h

Includes: SO2 balance of 95,443 and NOx balance of 250.

Schedule Page: 228 Line No.: 1 Column: i

$277,500 represents cost of 250 NOx Allowances for vintage year 2007.

Schedule Page: 228 Line No.: 1 Column: j

Includes: SO2 balance of 2,427,590 and NOx balance of 250.

Schedule Page: 228 Line No.: 1 Column: k

$277,500 represents cost of 250 NOx Allowances for vintage year 2008.

Schedule Page: 228 Line No.: 9 Column: l

33,261 transferred from vintage year 2004.

Schedule Page: 228 Line No.: 22 Column: b

33,261 transferred to vintage year 2009.

Schedule Page: 228 Line No.: 26 Column: c

$260,073 represents the Co-owner's portion of Campbell 3.

MISCELLANEOUS CURRENT AND ACCRUED ASSETS (Account 174)

1. Give description and amount of other current and accrued assets as of end of year.
2. Minor items may be grouped by classes, showing number of items in each class.

Line No.	Item (a)	Balance End of Year (b)
1	Prepaid Real and Personal Property Taxes	151,900,000
2		
3	Fiscal Year Real and Personal Property Taxes-Electric	47,494,219
4		
5	PSCR Underrecovery Principal	187,995
6		
7	Fiscal Year Real and Personal Property Taxes-Gas	16,659,094
8		
9	Accrued Value Services	600,156
10		
11	Interstate Gas - Pipeline Imbalance	1,175,226
12		
13	Fiscal Year Real & Personal Property Taxes-NonUtility	135,440
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		
39		
40		
41	TOTAL	218,152,130

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	UNRECOVERED PLANT _ ABANDONED			407	518,516	9,835,861
22	MIDLAND PROJECT					
23	Authorized 12/26/89 (effective					
24	1/1/89) by Federal Energy					
25	Regulatory Commission (FERC) case					
26	Number ER90-69-000. This amount					
27	represents the wholesale portion					
28	of the unrecovered cost of the					
29	abandoned Midland project, con-					
30	sistant with FERC Order Number					
31	295.					
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL				518,516	9,835,861

OTHER REGULATORY ASSETS

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory assets being amortized, show period of amortization in column (a).
3. Minor items (amounts less than $50,000) may be grouped by classes.
4. Give the number and name of the account(s) where each amount is recorded.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	Credits		Balance at End of Year (e)
			Account Charged (c)	Amount (d)	
1	Manufactured Gas Plant Environmental Cleanup	9,234,876	242/253/925	12,013,490	64,501,605
2	AFUDC in Excess of FERC Rate (Life of Related				
3	Property)	0	407/421	652,176	386,151
4	Postretirement Benefits (20 yrs-ending 2011)	0	926	23,178,603	158,001,260
5	SFAS 109 Regulatory Asset	0	410	1,628,844	28,233,296
6	Securitized Regulatory Asset (1)		407	42,986,548	604,122,452
7	Securitized Regulatory Asset II (2)	330,490	923	1,013,084	0
8	Incremental Gas Choice	0		0	590,390
9	Green Power - Implementation Costs (U - 13029)	0		0	311,028
10	Other PA 141 Deferrals (8)	150,522,533	565	3,219,315	147,303,218
11	PA141/Enhanced Security Costs (3)	21,231,577	407	1,305,202	25,646,927
12	FAS 143-ARO Asset	35,530,548	108/411	1,396,058	82,791,445
13	Electric Restructuring (4-7)	6,163,594	407	9,371,622	87,883,937
14	Gas Storage Field Inventory Loss	8,256,234		0	8,256,234
15	Stranded Cost (9)	63,581,887	407	420,905	63,160,982
16	Additional Minimum Pension Liability	372,170,952		0	372,170,952
17					
18					
19					
20					
21					
22					
23					
24					
25	(1) U12505 (14 Years Ending 2015)				
26	(2) U13715 (costs written off)				
27	(3) U-14126 (5 Years, Ending 2009)				
28	(4) U-11955 (4 Years, Ending 2008)				
29	(5) U-12358 (4 Years, Ending 2008)				
30	(6) U-12891 (4 Years, Ending 2008)				
31	(7) U-13340 (4 Years, Ending 2008)				
32	(8) PA 141 Deferral, Prior Period Adjustment				
33	(9) U-13720 & U-14098 (Amortized until fully recovered)				
34					
35					
36					
37					
38					
39					
40					
41	TOTAL	667,022,691		97,185,847	1,643,359,877

MISCELLANEOUS DEFERRED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a).
3. Minor items (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debit (a)	Balance at Beginning of Year (b)	Debits (d)	Credits Account Charged	Credits Amount (e)	Balance at End of Year (f)
1	Purch Power Options-Electric	0	19,268,064	555	7,009,078	12,258,986
2	Early Retirement Supplement	468,657	0	431	468,657	0
3	Campbell 3 Co-Owner Fuel	19,849	6,346,429	143	6,307,807	58,471
4	FAS 133-Purchase Power Options	20,419,627	5,521,238	555	25,940,865	0
5	Sales of Land & Right of Way	(904,296)	7,136,616	Various	5,981,503	250,817
6	Downtown HDQT Project	(127,319)	2,527,614	131	2,400,295	0
7	Alliance Bridgeco	4,892,772		131	37,595	4,855,177
8	Additional Pension Liability	0	21,210,604			21,210,604
9	Est Billing from CMS Enterpses	98,955	1,622,909	234	1,721,864	0
10	JH Campbell Transformer loss	1,721,075	643,831		0	2,364,906
11	FAS 133-Gas Options Prem Paid	4,143,166	59,431,009	421	62,095,717	1,478,458
12	Minor Items (8 Items <$50,000)	50,245	854,651	Various	888,072	16,824
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28	Misc. Work in Process					
29	TOTAL	30,782,731	124,562,965		112,851,453	42,494,243

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. For Other (Specify), include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Account No.	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Account 190				
2	Electric				
3	1989 SRS Supplement	007	499,750	0	0
4	'95 Biennial Conservation Program	027	(1)	0	0
5	Aetna Reserve	098	1,130,977	405,505	164,114
6	Bad Debt Expense	051	1,157,836	195,275	161,251
7	Big Rock Decommissioning Costs	002/018	2,170,132	2,505,162	341,600
8	Other (See line 24 , Page 234A-1)		297,291,358	26,873,727	34,991,632
9	TOTAL Electric (Enter Total of lines 2 thru 7)		302,250,051	29,979,669	35,658,597
10	Gas				
11	'95 Biennial Conservation Program	028	(625)	0	625
12	Aetna Reserve	099	630,066	183,224	72,030
13	Bad Debt Expense	052	1,458,629	283,296	413,591
14	Contributions in Aid of Construction	033	14,142,851	505,429	0
15	Chase/Manhattan Swap Agreement - Deferred Gain	157	84,671	287,746	340,891
16	Other (See line 55, page 234A-2)		380,799,562	16,691,280	33,510,388
17	TOTAL Gas (Enter Total of lines 10 thru 15)		397,115,154	17,950,975	34,337,525
18	Other (Specify) (See line 79, page 234A-2)		59,038,933	0	0
19	TOTAL (Account 190) (Enter Total of 8, 16 and 17		758,404,139	47,930,644	69,996,123
20	Classification of Total:				
21	Federal Income Tax		758,404,139	47,930,644	69,996,123
22	State Income Tax		-	-	-
23	Local Income Tax		-	-	-

NOTES

In the space provided below, identify by amount and classification, significant items for which deferred taxes are being provided.

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

3. If more space is needed, use separate pages as required.
4. In the space provided below, identify by amount and classification, significant items for which deferred taxes are being provided. Indicate insignificant amounts listed other Other.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
						499,750	3
						(1)	4
						889,586	5
						1,123,812	6
				283020	1,547,500	1,554,069	7
			4,341,155		53,740,745	354,808,852	8
0	0		4,341,155		55,288,245	358,876,069	9
							10
						0	11
						518,872	12
						1,588,924	13
		282.112				13,637,422	14
				190158	2,416	140,232	15
			23,034,879		179,010	374,762,801	16
0	0		23,034,879		181,426	390,648,251	17
12,474,426	11,689,422		7,769		1,517,329	59,763,489	18
12,474,426	11,689,422		27,383,803		56,987,000	809,287,809	19
							20
12,474,426	11,689,422		27,383,803		56,987,000	809,287,809	21
-	-		-		-	-	22
-	-		-		-	-	23

NOTES: In the space provided below, identify by amount and classification, significant items for which deferred taxes are being provided.

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

Line No.	Account Subdivisions (a)	Account No.	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
24	Electric Other (Detail of Line 7)				
25	Accretion - Options Payable	162	2,173,567	0	544,489
26	ARO Profit Margin Accretion - BR	001	963,986	0	144,417
27	ARO Profit Margin Accretion - Palisades	069	(520,503)	0	47,744
28	CATV Deferred Revenue	173	526,703	844,472	906,565
29	Campbell 3 Deferred Revenue	040	267,805	533,982	509,847
30	Chase/Manhattan Swap Agreement - Deferred Gain	156	289,501	824,945	958,399
31	Clean Air Allowance - 2001	159	0	0	189,645
32	Contributions in Aid of Construction	026	15,748,368	745,066	0
33	Deferred AMT	56	3,805,256	0	1,245,825
34	Deferred Compensation	108	1,131,121	330,662	524,220
35	DOE Decommissioning	131/132	2,382,655	913,989	0
36	EICP	147	3,536,119	2,830,078	3,669,683
37	FAS 148-STK Option Fair Value	176	307,295	0	0
38	Fly Ash Trust Fund	169	196,469	0	12,591
39	General Business Credits	189	0	0	412,878
40	Injuries & Damages	096/130	4,052,035	323,036	2,658,286
41	Insurance Recovery	043	1,239	0	0
42	MSBT Reserve	061	2,864,750	0	0
43	NOL Carryforward - Electric	180	9,135,951	0	433,138
44	Offshore Insurance Liability (OIL)	195	0	0	1,049,601
45	OPEB Obligation	86-8&138-40	55,905,425	13,274,308	10,773,014
46	Outside Services - Audit Accrual	166	84,569	382,987	490,577
47	Palisades Decommissioning Costs	005/016	56,942,925	147,790	4,230,461
48	Pension Costs	065	19,662,766	4,293,229	116,290
49	PSCR Contingency	021	10,751,529	759,556	3,955,043
50	Sales&Use Tax Reserve	067	535,500	0	1,214,500
51	Save & Share	145	540,353	0	221,534
52	Savings Plan - Rabbi Trust	170	74,664	17,532	2,781
53	Senior Reactor Operator Retention Liability	165	483,840	0	25,480
54	Special Compensation (SEMP) - Electric	012	1,111,213	0	352,376
55	SRS Supplemental Program	003	1,010,520	140,178	25,521
56	SRS Excess Liability (OCI)	76	0		
57	Tax Interest During Construction	034	11,428,094	511,916	0
58	Vacation Pay Accrual	053	1,301,536	0	274,848
59	Wurtsmith Escrow	022	40,659	0	1,880
60	FAS 109-Accumulated Def.Tax Benefits-ITC	191.200	20,745,985	0	0
61	FAS 109-Accumulated Def.Tax Benefits-Other	191.202	426,890	0	0
62	FAS 109-Accumulated DFIT Benefit-Reg Lia	191.205	31,499,267		
63	FAS 109-Accumulated DFIT Benefit-Property	191.206	37,883,306		
64	Total Electric Other		297,291,358	26,873,727	34,991,632

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (CONTINUED)

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							24
		283.161	641,930			2,076,126	25
						1,108,403	26
						(472,759)	27
						588,796	28
						243,670	29
				190157/8	5,353	428,308	30
						189,645	31
		282.111				15,003,302	32
		190180				5,051,081	33
						1,324,679	34
						1,468,666	35
						4,375,724	36
						307,295	37
						209,060	38
						412,878	39
						6,387,285	40
						1,239	41
						2,864,750	42
				190056		9,569,089	43
						1,049,601	44
		190/282/283	2,234,579	190/282	80,979	51,250,531	45
						192,158	46
						61,025,596	47
				283.184/186		15,485,827	48
		190.071				13,947,016	49
						1,750,000	50
						761,887	51
						59,913	52
						509,320	53
						1,463,589	54
						895,863	55
				219.047	398,440	398,440	56
						10,916,178	57
						1,576,384	58
						42,539	59
		286.101	1,037,669			19,708,316	60
		286.103	426,978			-88	61
				286.103	18,130,100	49,629,367	62
				286103	35,125,873	73,009,179	63
0	0		4,341,155		53,740,745	354,808,852	64

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

Line No.	Account Subdivisions (a)	Account No.	Balance at Beginning of Year (b)	Changes During Year: Amounts Debited to Account 410.1 (c)	Changes During Year: Amounts Credited to Account 411.1 (d)	Changes During Year: Amounts Debited to Account 410.2 (e)
65	Gas Other (Detail of Line 15)					
66	Deferred AMT	57	1,254,006	0	4,745,601	
67	Deferred Compensation	109	1,033,959	313,433	503,663	
68	Deferred Revenue-Appliance Service Program	163	323,065	143,809	55,029	
69	EICP	148	2,475,310	2,062,416	2,300,988	
70	FAS 148-Stock Option Fair Value	177	295,245	0	0	
71	Gas Inventory Capitalization	060	(1,110,760)	0	10,735,468	
72	Gas Inventory Linepack	024	1,863,063	0	460,644	
73	GCR Contingency	068/101	5,487,598	2,071,866	735,602	
74	General Business Credit	190	0	0	1,572,736	
75	Grand Lacs Deferred Revenue	150	(320,480)	0	0	
76	Injuries & Damages	097/135	180,840	378,702	2,518,133	
77	Insurance Recovery - MGP	042	6,387,901	1,714,172	15,528	
78	Manufactured Gas Plants Environmental Clean-up	137	26,872,194	0	0	
79	MSBT Reserve	116	1,335,250	0	0	
80	NOL Carryforward - Gas	181	3,007,974	0	1,649,911	
81	Offshore Insurance Liability (OIL)	195	0	0	1,095,941	
82	OPEB Obligation	087/089/151	33,861,494	7,216,566	5,958,881	
83	Outside Service - Audit Expense	167	80,281	375,835	478,938	
84	Pension Costs	066	10,400,374	2,370,499	51,424	
85	Ray Storage Losses	011	2,640,799	0	0	
86	Sales&Use Tax Reserve	117	514,500	0	325,500	
87	Save & Share	146	249,113	0	93,184	
88	Savings Plan - Rabbi Trust	171	39,332	13,165	1,328	
89	Special Compensation (SEMP) - Gas	013	553,236	0	172,931	
90	SRS Supplemental Payment	004	735,018	68,203	12,396	
91	SRS Excess Liability (OCI)	76	0			
92	Take or Pay Order 500	019	27,983,752	0	0	
93	Tax Interest During Construction	035	1,927,361	65,515	0	
94	Vacation Pay Accrual	054	612,489	(102,900)	26,563	
95	FAS 109-Accumulated DFIT Benefit-ITC	191.201	6,690,866	0	0	
96	FAS 109-Accumulated DFIT Benefit-Other	191.203	95,395	0	0	
97	FAS 109-Accumulated DFIT Benefit-Reg Liability	191.204	88,240,828	0	0	
98	FAS 109-Accumulated DFIT Benefit-Property	191.207	157,089,561			
99	Total Gas Other		380,799,562	16,691,280	33,510,388	0
100						
101	Other (Detail of Line 17)					
102	Bad Debt Expense	50	123,277			20,827
103	Chase/Manhattan Swap Agreement - Deferred Gain	158	53,015			146,579
104	CP Foundation	029/030	141,088			55,248
105	Contribution Carryover	128/129	4,309,706			0
106	Deferred AMT	058/174/175	774,584			0
107	Energyguard	063	734			(174)
108	FAS 115 - Nuclear Decommissioning	141/142/152	36,859,151			0
109	General Business Credit	191/192/193	0			0
110	MCV Contract Loss	106/107	9,251,328			9,251,328
111	NOL Carryforward - Other	182/3/4	1,859,679			0
112	Nuclear Simulator	126	2,595,826			0
113	PSCR Contingency - Interest	071	3,006,843			3,000,584
114	PSI Line Write-off	136	(140,464)			35
115	Realized Gain SERP Plan Assets	187/188	204,168			0
116	Total Other		59,038,933	0	0	12,474,426

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

Changes During Year	Adjustments					
Amounts Credited to Account 411.2 (f)	Debits		Credits		Balance at End of Year (k)	Line No.
	Account No. (g)	Amount (h)	Account No. (i)	Amount (j)		
						65
	190.181				5,999,607	66
					1,224,189	67
					234,285	68
					2,713,882	69
					295,245	70
					9,624,708	71
					2,323,707	72
					4,151,334	73
					1,572,736	74
					(320,480)	75
					2,320,271	76
					4,689,257	77
	283.137	13,620,495			13,251,699	78
					1,335,250	79
			190057		4,657,885	80
					1,095,941	81
	282/283	1,190,809	190089		31,413,001	82
					183,383	83
			283.185/187		8,081,299	84
					2,640,799	85
					840,000	86
					342,297	87
					27,495	88
					726,167	89
					679,211	90
			219.047	179,010	179,010	91
					27,983,752	92
					1,861,846	93
					741,952	94
	286.102	302,280			6,388,586	95
	286.100	95,395			0	96
	286.100	2,878,252			85,362,576	97
	286.100	4,947,648			152,141,913	98
0		23,034,879		179,010	374,762,801	99
						100
						101
79,725					182,175	102
169,653	190158	7,769			68,320	103
317,444	190128/129				403,284	104
83,275			190029/030		4,392,981	105
5,953,203	190xxx				6,727,787	106
0			123109		908	107
0			283.111/112	1,517,329	38,376,480	108
1,972,947					1,972,947	109
0					(0)	110
2,069,760			190xxx		3,929,439	111
0					2,595,826	112
749,469			190.021		755,727	113
0			283.169		(140,499)	114
293,947					498,115	115
11,689,422		7,769		1,517,329	59,763,489	116

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Accounts 189, 257)

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, particulars of gain and loss on reacquisition applicable on each class and series of long-term debt, including maturity date. If gain or loss resulted from a refunding transaction, include also the maturity date of new issue.

2. In column (c) show the principal amount of bonds or other long-term debt reacquired.
3. In column (d) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 16 of the Uniform System of Accounts.

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Principal Amount of Debt Reacquired (c)	Net Gain or Net Loss (d)
1	UNAMORTIZED LOSS ON REAQUIRED DEBT			
2				
3	Installment Sales Contracts			
4				
5	Refunded by Pollution Control Revenue Refunding Bond due 2018			
6	Charter Township of Hampton - Due 2000	6-1-88	15,800,000	(620,649)
7	Port Sheldon Township - Due 2000	6-1-88	8,400,000	(357,767)
8	Econ Dev Corp - Port Sheldon Township - Due 1991	6-1-88	43,500,000	(761,363)
9	Cost of Issuing Pollution Control			
10	Revenue Refunding Bond due 2018			(846,579)
11				
12			67,700,000	(2,586,358)
13				
14				
15				
16	Refunded by Pollution Control Revenue Refunding Bond Series '93A			
17	due 2010			
18	Covert Township, Series A - Due 2003	8-1-93	11,100,000	(69,344)
19	Charter Township of Hampton, Series A - Due 2004	8-1-93	8,900,000	(74,999)
20	Township of Port Sheldon, Series B - Due 1993-2007	8-1-93	7,900,000	(134,590)
21				
22			27,900,000	(278,933)
23				
24				
25				
26	Refunded by Pollution Control Revenue Refunding Bond Series '93B			
27	due 2010			
28	Covert Township, Series A - Due 2003	8-1-93	11,900,000	(74,564)
29	Charter Township of Hampton, Series A - Due 2004	8-1-93	9,600,000	(80,644)
30	Township of Port Sheldon, Series B - Due 1993-2007	8-1-93	8,500,000	(144,720)
31	Cost of Issuing Pollution Control Revenue Refunding Bond due 2010			(633,292)
32			30,000,000	(933,220)
33				
34				
35				
36				

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Accounts 189, 257) (continued)

4. Show loss amounts in red or by enclosure in parentheses.
5. Explain any debits and credits other than amortization debited to Account 428.1,

Amortization of Loss on Reacquired Debt or credited to Account 429.1, Amortization of Gain on Reacqired Debt-Credit.

Balance Beginning of Year (e)	Debits During Year (f)	Credits During Year (g)	Balance End of Year (h)	Line No.
				1
				2
				3
				4
				5
220,781	0	15,412	205,369	6
127,335	0	8,880	118,455	7
270,953	0	18,900	252,053	8
				9
303,293	0	21,159	282,134	10
				11
922,362	0	64,351	858,011	12
				13
				14
				15
				16
				17
19,666	0	3,085	16,581	18
21,346	0	3,332	18,014	19
39,206	0	5,924	33,282	20
				21
80,218	0	12,341	67,877	22
				23
				24
				25
				26
				27
21,145	0	776	20,369	28
22,952	0	841	22,111	29
42,159	0	1,553	40,606	30
0	633,292	29,853	603,439	31
86,256	633,292	33,023	686,525	32
				33
				34
				35
				36

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Accounts 189, 257) (continued)

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Principal Amount of Debt Reacquired (c)	Net Gain or Net Loss (d)
	First Mortgage Bonds			
37	Refunded by First Mortgage Bond due 2023			
38	9% First Mortgage Bond due 2008	9-15-93	33,260,000	(1,584,920)
39	8-7/8% First Mortgage Bond due 2007	9-15-93	85,000,000	(4,006,953)
40	8-5/8% First Mortgage Bond due 2007	9-15-93	100,000,000	(4,584,804)
41	9% First Mortgage Bond due 2006	9-15-93	39,376,000	(1,779,654)
42	7-5/8% First Mortgage Bond due 1999	2-7-94	22,285,000	(460,236)
43	7-1/8% First Mortgage Bond due 2002	2-7-94	20,079,000	(393,922)
44	Refunding of 5.00% FMB due 2015			
45			300,000,000	(12,810,489)
46	Refunded by 5.00% FMB due 2015			
47	7-3/8% First Mortgage Bond due 2023	12-8-04	207,700,000	(18,694,148)
48	Refunded by 6.2% due 5/1/08	5-1-98		
49	7 3/8% Due 2023		35,750,000	(3,116,995)
50	Refunded by 6.5% due 6/15/18	11-16-98		
51	8 7/8% Due 1999		64,182,000	(6,117,844)
52	Refunded by 6 7/8% due 3/01/18	9-18-98		
53	7.5% Due 2001		57,164,000	(554,491)
54	Refunded by 6 7/8% due 3/01/18	9-18-98		
55	7.5% Due 2002		62,174,000	(686,401)
56	Refunded by 6% Senior Note due 3/15/05	3-18-02		
57	6 3/8% Due 2003		300,000,000	(1,419,709)
58	Refunded by 4.25% due 4/15/08 and 5.375% due 4/15/13			
59	6.2% Senior note Due 2008	5-1-03	250,000,000	(32,386,165)
60	Refunded by 4% due 2010, 4.8% due 2009 and 6% due 2014			
61	Long-term bank loan due July 2004	5-16-03	100,000,000	
62	Long-term bank loan due July 2004	6-2-03	150,000,000	(7,245,805)
63	Long-term bank loans due July 2004	8-29-03	200,000,000	(2,241,188)
64				
65	Refunded by 4.4% due 2009, 5.0% due 2012, and 5.5% due 2016			
66	Long-term bank loan due March 2009	8-12-04	140,000,000	(4,577,688)
67	6.5% Senior Note due 2018	8-12-04	141,000,000	(9,604,074)
68	6.0% Senior Note due 2005	8-12-04	300,000,000	(4,802,375)
69				
70				
71				
72				

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Accounts 189, 257) (continued)

Balance Beginning of Year (e)	Debits During Year (f)	Credits During Year (g)	Balance End of Year (h)	Line No.
				37
647,075	0	32,901	614,174	38
1,645,290	0	82,784	1,562,506	39
1,876,460	0	94,989	1,781,471	40
727,721	0	36,881	690,840	41
193,592	0	9,552	184,040	42
164,314	0	8,226	156,088	43
		4,989,119	(4,989,119)	44
5,254,452	0	5,254,452	0	45
				46
0	18,694,148	0	18,694,148	47
				48
1,799,836	0	1,799,836	0	49
				50
3,303,529	0	3,303,529	0	51
				52
292,021	0	20,493	271,528	53
				54
359,814	0	25,250	334,564	55
				56
595,048	0	595,048	0	57
				58
29,363,456	0	4,534,062	24,829,394	59
				60
				61
6,641,988	0	1,035,115	5,606,873	62
2,137,699	0	310,467	1,827,232	63
				64
				65
0	4,577,688	186,999	4,390,689	66
0	9,604,074	392,326	9,211,748	67
0	4,802,375	196,177	4,606,198	68
				69
				70
				71
				72

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Accounts 189, 257) (continued)

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Principal Amount of Debt Reacquired (c)	Net Gain or Net Loss (d)
	Other Long-term Debt			
73	Replacement of Revolving Credit Agreement			
74	Revolving Credit Agreement-unamortized debt costs	4-30-03	0	(846,182)
75				
76				
77				
78				
79				
80				
81				
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105				
106				
107				
108	Total			

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Accounts 189, 257) (continued)

Balance Beginning of Year (e)	Debits During Year (f)	Credits During Year (g)	Balance End of Year (h)	Line No.
				73
211,546	0	211,546	0	74
				75
				76
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				106
				107
			71,384,787	108

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201 - Common Stock *	125,000,000	10.00	
2	Total Common Stock	125,000,000		
3				
4	Account 204 - Preferred Stock	441,599		
5	Preferred Stock - $4.50 Cum **		100.00	110.00
6	Preferred Stock - $4.16 Cum **		100.00	103.25
7				
8	Total Preferred Stock	441,599		
9				
10				
11	* Stock held by parent holding company, CMS			
12	Energy Corporation			
13				
14	** New York Stock Exchange			
15				
16				
17				
18				
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41				
42				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
84,108,789	841,087,890					1
84,108,789	841,087,890					2
						3
						4
373,148	37,314,800					5
68,451	6,845,100					6
						7
441,599	44,159,900					8
						9
						10
						11
						12
						13
						14
						15
						16
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						40
						41
						42

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CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK AND INSTALLMENTS RECEIVED ON CAPITAL STOCK
(Accounts 202 & 205, 203 & 206, 207 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock
2. For Account 202, *Common Stock Subscribed,* and Account 205, *Preferred Stock Subscribed,* show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, *Common Stock Liability for Conversion,* or Account 206, *Preferred Stock Liability for Conversion,* at the end of the year.
4. For Premium on Account 207, *Capital Stock,* designate with a double asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account & Description of Item (a)	Number of Shares (b)	Amount (c)
1	Account 202 - None		
2			
3	Account 203 - None		
4			
5	Account 205 - None		
6			
7	Account 206 - None		
8			
9	Account 207		
10	Premium on Common Stock	84,108,789	386,028,613
11			
12	Account 212 - None		
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
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24			
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26			
27			
28			
29			
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31			
32			
33			
34			
35			
36			
37			
38			
39			
40	TOTAL	84,108,789	386,028,613

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries affecting such change.

(a) *Donations Received from Stockholders* (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) *Reduction in Par or Stated Value of Capital Stock* (Account 209)-State amount and give brief explanation of the capital changes which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) *Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210)*- Report balance at end of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) *Miscellaneous Paid-in Capital* (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208	
2	Donations Received from Stockholders:	
3	Cash Infusions-CMS Energy-Prior to 2003	298,198,250
	CMS Engineering Stock-Prior to 2003	81,351
4	Cash Infusions-CMS Energy-Aug 04	150,000,000
	Cash Infusions-CMS Energy-Nov 04	100,000,000
5	Subtotal 208	548,279,601
6		
7		
8	Subtotal 209 - None	
9		
10	Account 210	
11	Gain on Reacquired Capital Stock - Prior to 2003	20,440,268
12		
13		
14	Account 211	
15	Paid-in-Capital - Prior to 2003	293,744
16	SERP Market Value - FAS 115-Unrealized Investment Gain (loss), Net of Tax	2,405,164
17	Interest Rate Hedge-FAS 133 Unrealized Loss	(775,340)
18	CMS Energy Stock-FAS 115 Unrealized gain/(loss), Net of Tax	9,268,063
19	CMS Midland - FAS 133 Unrealized Gain (loss), Net of Tax	20,949,448
20		
21	Subtotal 211	32,141,079
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35	TOTAL	600,860,948

DISCOUNT ON CAPITAL STOCK (Account 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off during the year and specify the amount charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	None	
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17	TOTAL	

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of year of capital stock expenses for each class and series of capital stock.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off during the year and specify the amount charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	23,596,832
2	$4.16 Preferred Stock	121,741
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18	TOTAL	23,718,573

SECURITIES ISSUED OR ASSUMED AND SECURITIES REFUNDED OR RETIRED DURING THE YEAR

1. Furnish a supplemental statement giving a brief description of security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses. Identify as to Commission authorization numbers and dates.
2. Furnish particulars (details) showing fully the accounting for the total principal amount, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gains or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.

Series	DEBIT (CREDIT) Account 131 Cash	Account 181 Unamortized Debt Expense	Account 221 Bonds
FIRST MORTGAGE BONDS ISSUED IN 2004			
4.4% FMB due 8-15-09	145,398,567	1,022,407	(150,000,000)
5.0% FMB due 2-15-12	290,472,351	2,093,597	(300,000,000)
5.0% FMB due 3-15-15	204,349,798	1,580,304	(225,000,000)
5.5% FMB due 8-15-16	337,422,724	2,602,216	(350,000,000)
FIRST MORTGAGE BONDS RETIRED IN 2004			
7 3/8% FMB due 2023	(192,027,512)		207,700,000
TOTAL FIRST MORTGAGE BONDS	785,615,928	7,298,524	(817,300,000)
OTHER LONG TERM DEBT			
Senior Notes Retired or Paid Down			
6.5% Senior Note due 06-18 (2)	(138,290,380)	(925,201)	
6.0% Senior Note due 03-05 (2)	(307,384,353)	(259,824)	
6.5% Senior Note Due 10-1-28	(657,538)	(44,979)	
Bank Term Loans Retired, Issued or Paid Down			
Beal Bank Loan due 2009 (2)	(136,623,749)	(4,577,688)	
DOE SNF Disposal Contract (1)	1,732,739		
Issued & Retired, PCRB			
$30M PCRB due 06-10	28,213,800	1,077,711	
$30M PCRB due 06-10	(30,157,012)	(333,291)	
TOTAL OTHER LONG-TERM DEBT	202,449,435	2,235,252	(817,300,000)

(1) Account debited is interest expense
(2) Debt retired using three Bond issuances.

SECURITIES ISSUED OR ASSUMED AND SECURITIES REFUNDED OR RETIRED DURING THE YEAR (Continued)

3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of principal underwriting firm through which the security transactions were consummated.
4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 16 of the Uniform System of Accounts, give references to the Commission authorization for the different accounting and state the accounting method.

5. For securities assumed, give the name of the company for which the liability on the securites was assumed as well as particulars (details) of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discounts, premiums, expenses, and gains or losses were taken over into the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

			DEBIT (CREDIT)					
Account 224/242 Other Long-Term Debt	Account 225 Unamortized Premium		Account 226 Unamortized Discount		Account 237 Interest Accrued	Account 189 Unamortized Loss on Reacquired Debt	Account 182 Regulatory Asset	
			19,500			3,559,526		
			315,000			7,119,052		
			375,750			18,694,148		
			1,669,500			8,305,560		
			(4,506,820)		(4,467,598)	(6,698,070)		
0	0		(2,127,070)	0	(4,467,598)	30,980,216	0	0
141,000,000			(1,246,613)		2,596,750	(3,134,556)		
298,657,559			(12,139)		9,250,000	(251,243)		
750,000			(51,545)		4,062	0		
140,000,000					1,201,437			
(1,732,739)								
(30,000,000)						708,489		
30,000,000					565,500	(75,197)		
578,674,820	0		(3,437,367)	0	9,150,151	28,227,709	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221		
2	7-3/8% Series Due 2023	300,000,000	2,899,221
3			7,254,000 D
4	4.25% Series A, Due 2008	250,000,000	1,805,067
5			570,000 D
6			12,954,466
7	5.375% Series B, Due 2013	375,000,000	2,805,845
8			1,788,750 D
9			19,431,699
10	4% Seires E, Due 2010	250,000,000	1,871,930
11			1,247,500 D
12			7,245,805
13	4.8% Series G, Due 2009	200,000,000	1,436,938
14			454,000 D
15			1,120,594
16	6.0% Series I, Due 2014	200,000,000	1,536,904
17			318,000 D
18			1,120,594
19	4.40% Series K, Due 2009	150,000,000	1,022,407
20			19,500 D
21			3,559,526
22	5.00% Series L, Due 2012	300,000,000	2,093,597
23			315,000 D
24			7,119,052
25	5.50% Series M, Due 2016	350,000,000	2,602,217
26			1,669,500 D
27			8,605,560
28	5.00%, Due 2015	225,000,000	1,580,164
29			375,750 D
30			18,694,148
31	Subtotal Account 221 - First Mortgage Bonds	2,600,000,000	113,517,734
32			
33	TOTAL	5,379,274,525	173,803,957

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
09/15/93	09/15/23	09/15/93	09/15/23		15,317,876	2
						3
04/30/03	04/15/08	04/30/03	04/15/08	250,000,000	10,625,000	4
						5
						6
04/30/03	04/15/13	04/30/03	04/15/13	375,000,000	20,156,250	7
						8
						9
05/23/03	05/15/10	05/23/03	05/15/10	250,000,000	10,000,000	10
						11
						12
08/26/03	02/17/09	08/26/03	02/17/09	200,000,000	9,573,333	13
						14
						15
08/26/03	02/15/14	08/26/03	02/15/14	200,000,000	11,966,667	16
						17
						18
08/17/04	08/15/09	08/17/04	08/15/09	150,000,000	2,438,333	19
						20
						21
08/17/04	08/15/12	08/17/04	08/15/12	300,000,000	5,541,667	22
						23
						24
08/17/04	08/15/16	08/17/04	08/15/16	350,000,000	7,111,806	25
						26
						27
12/13/04	03/15/15	12/13/04	03/15/15	225,000,000	531,250	28
						29
						30
				2,300,000,000	93,262,182	31
						32
				4,261,332,362	241,996,569	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 222		
2	None		
3			
4	ACCOUNT 223		
5	Subordinated Deferred Interest Note - Consumers Power Company Financing I	103,092,800	3,079,085
6	Subordinated Deferred Interest Note - Consumers Energy Company Financing II	123,711,350	4,018,291
7	Subordinated Deferred Interest Note - Consumers Energy Company Financing III	180,412,375	5,572,625
8	Subordinated Deferred Interest Note - Consumers Energy Company Financing IV	128,866,000	4,239,936
9			
10	Note Payable - Consumers Funding - LLC #2	84,000,000	11,423 D
11			8,333
12	Note Payable - Consumers Funding - LLC #3	31,000,000	6,040 D
13			8,333
14	Note Payable - Consumers Funding - LLC #4	95,000,000	21,872 D
15			8,333
16	Note Payable - Consumers Funding - LLC #5	117,000,000	28,148 D
17			8,333
18	Note Payable - Consumers Funding - LLC #6	115,592,000	30,529 D
19			8,335
20	Subtotal Account 223 - Advances from Associated Companies	978,674,525	17,049,616
21			
22			
23			
24	ACCOUNT 224		
25	Other Long-Term Debt		
26	Variable Rate Demand Pollution Control Revenue Refunding Bonds:		
27	Michigan Strategic Fund - 1988	67,700,000	614,195
28			
29	Limited Obligation Refunding Revenue Bonds:		
30	Michigan Strategic Fund Series '93A	27,900,000	331,606
31	Michigan Strategic Fund Series '93B	30,000,000	982,485
32	Department of Energy - Spent Nuclear Fuel Liability		
33	TOTAL	5,379,274,525	173,803,957

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
01/23/96	12/31/15	01/23/96	12/31/15	73,092,800	6,110,558	5
09/11/97	09/01/27	09/11/97	09/01/27	123,711,350	10,144,331	6
11/04/99	12/31/29	11/04/99	12/31/29	180,412,375	16,688,145	7
05/31/01	06/30/31	05/31/01	06/30/31	128,866,000	11,597,940	8
						9
11/08/01	01/20/06	11/08/01	01/20/06	1,220,854	1,965,430	10
						11
11/08/01	01/20/07	11/08/01	01/20/07	31,000,000	1,410,500	12
						13
11/08/01	01/20/10	11/08/01	01/20/10	95,000,000	4,731,000	14
						15
11/08/01	01/20/13	11/08/01	01/20/13	117,000,000	6,353,100	16
						17
11/08/01	07/20/15	11/08/01	07/20/15	115,592,000	6,817,243	18
						19
				865,895,379	65,818,247	20
						21
						22
						23
						24
						25
						26
04/26/88	04/15/18	04/26/88	04/15/18	67,700,000	1,265,407	27
						28
						29
06/29/93	06/15/10	06/29/93	06/15/10	27,900,000	534,595	30
06/29/93	06/15/10	06/29/93	06/15/10	30,000,000	1,759,458	31
				96,578,879	1,732,739	32
				4,261,332,362	241,996,569	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	Long-Term Bank Credit Agreement, Docket No. ES02-36-000 et al., 06/27/03	140,000,000	2,266,101
3	Long-Term Bank Credit Agreement, Docket No. ES02-36-000 et al., 06/27/03	60,000,000	9,538
4			
5	Senior Notes:		
6	6-3/8% Due 2/1/08 Docket No. ES97-7-000 11/27/96 & 1/30/98	250,000,000	1,812,677
7			2,417,500 D
8			-1,660,538
9	6-7/8% Due 3/1/18 Docket No. ES97-7-000, 11/27/96, 1/30/98, 2/27/98	225,000,000	2,097,242
10			3,307,500 D
11			-3,377,696
12	6-1/2% 6/15/18 Docket No. ES97-7-000, 11/27/96, 2/27/98, 6/1/98, 4/8/98	200,000,000	1,847,850
13			1,374,000 D
14			2,782,293
15	6-1/2% Due 10/1/28 Docket No. ES98-31-000, 6/8/98	150,000,000	11,237,264
16			12,681,925
17	6.25% Due 9/15/06 Docket No. ES00-28-000, 6/15/00	350,000,000	2,329,665
18			1,064,000 D
19	6.00% Due 3/15/05 Docket No ES02-37-000, 7/1/02	300,000,000	69,000
20			1,050,000 D
21	Interest Rate Hedges - Net Deferred Gains		
22	Subtotal Account 224 - Other Long-Term Debt	1,800,600,000	43,236,607
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	5,379,274,525	173,803,957

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
03/26/03	03/26/09	03/26/03	03/26/09		5,424,771	2
11/07/03	11/07/06	11/07/03	11/07/06	60,000,000	1,710,700	3
						4
						5
2/1/98	2/1/08	2/1/98	2/1/08	159,239,000	10,151,486	6
						7
						8
3/1/98	3/1/18	3/1/98	3/1/18	180,000,000	12,375,000	9
						10
						11
6/15/98	6/15/18	6/15/98	6/15/18		6,797,375	12
						13
		6/15/98	6/15/05			14
10/1/98	10/1/28	10/1/98	10/1/28	141,033,000	9,189,245	15
						16
09/26/01	09/15/06	09/26/01	09/15/06	332,250,000	20,812,389	17
						18
					11,162,975	19
3/15/02	3/15/05	3/15/02	3/15/05			20
				736,104		21
				1,095,436,983	82,916,140	22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				4,261,332,362	241,996,569	33

Schedule Page: 256 Line No.: 6 Column: c

Option fee

Schedule Page: 256 Line No.: 9 Column: c

Option fee

Schedule Page: 256 Line No.: 12 Column: c

Remaining unamortized debt discount and expense on reacquired debt

Schedule Page: 256 Line No.: 15 Column: c

Remaining unamortized debt discount and expense on reacquired debt

Schedule Page: 256 Line No.: 18 Column: c

Remaining unamortized debt discount and expense on reacquired debt

Schedule Page: 256 Line No.: 21 Column: c

Remaining unamortized debt discount and expense on reacquired debt

Schedule Page: 256 Line No.: 24 Column: c

Remaining unamortized debt discount and expense on reacquired debt

Schedule Page: 256 Line No.: 27 Column: c

Remaining unamortized debt discount and expense on reacquired debt

Schedule Page: 256 Line No.: 30 Column: c

Remaining unamortized debt discount and expense on reacquired debt

Schedule Page: 256.1 Line No.: 24 Column: a

RESPONSE TO INSTRUCTION 12

NET CHANGES TO ACCOUNT 223, ADVANCES FROM ASSOCIATED COMPANIES

Balance, Beginning of Year	$ 894,541,239
Additions During the Year:	0
Retirements During the Year:	
Note payable-Consumers Funding-LLC #2	(28,645,860)
Balance, End of Year	$ 865,895,379

NET CHANGES TO ACCOUNT 224, OTHER LONG-TERM DEBT

Balance, Beginning of Year	$ 1,679,052,149
Additions During the Year:	
Department of Energy - Increase in Spent Nuclear Fuel Liability	1,732,739
Michigan Strategic Fund Series '93B Refunding	30,000,000
Retirements During the Year:	
Michigan Strategic Fund Series '93B Refunding	(30,000,000)
Long-Term Bank Debt	(140,000,000)
Senior Note	(141,000,000)
Senior Note	(750,000)
Senior Note	(300,000,000)
Change in Interest Rate Hedges - Net Deferred Gains	(3,597,905)
Balance, End of Year	$ 1,095,436,983

RESPONSE TO INSTRUCTION 9

When an issue is redeemed, the difference between the amount paid upon reacquisition and the face value, less any unamortized discount, related debt expense and reacquisition costs is recognized currently in Account 426.5. An exception occurs if the issue redeemed is directly refinanced with a new issue; then amounts are amortized, over the life of the new issue (or the life of the previous refinancing issue) and not currently recognized.

RESPONSE TO INSTRUCTION 15

Account 427, Interest on Long-Term Debt, includes $19,917,884 of reversal of previously recorded Interest During Construction on capital expenditures. Account 430, Interest on Debt to Associated Companies, includes interest on short-term debt with associated companies.

RESPONSE TO INSTRUCTION 16

In June 2004, the FERC authorized Consumers to issue and sell up to $2.5 billion of long-term securities, of which up to $1.0 billion would be for refinancing or refunding purposes and up to $1.5 billion would be for general corporate purposes. Up to an additional $2.5 billion of first mortgage bonds were also authorized to be issued solely as security for other long-term securities. As of December 31, 2004 Consumers has $181 million and $1,264 million of the authorization remaining for refinancing and for general corporate purposes, respectivly. Consumers also had $2.47 billion remaining authorization of first mortgage bonds to be issued solely as security for other long-term issuances.

Schedule Page: 256.2 Line No.: 8 Column: c
Gain on Hedge Agreement

Schedule Page: 256.2 Line No.: 11 Column: c
Gain on Hedge Agreement

Schedule Page: 256.2 Line No.: 14 Column: c
Loss on Hedge Agreement

Schedule Page: 256.2 Line No.: 16 Column: c
Loss on Hedge Agreement

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PAYABLES TO ASSOCIATED COMPANIES* (Accounts 233, 234)

1. Report particulars of notes and accounts payable to associated companies at end of year.
2. Provide separate totals for Accounts 233, Notes Payable to Associated Companies, and 234, Accounts Payable to Associated Companies, in addition to a total for the combined accounts.
3. List each note separately and state the purpose for which issued. Show also in column (a) date of note, maturity and interest rate.
4. Include in column (f) the amount of any interest expense during the year on notes or accounts that were paid before the end of the year.
5. If collateral has been pledged as security to the payment of any note or account, describe such collateral.

* See definitions on page 226B

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year Debits (c)	Totals for Year Credits (d)	Balance End of Year (e)	Interest for Year (f)
1	ACCOUNT 233 - NOTES PAYABLE TO ASSOC CO					
2	CMS Midland, Inc.	10,000,000	0	0	10,000,000	201,433
3	CMS Energy Corporation	200,000,000	880,000,000	680,000,000	0	2,350,969
4	Consumers Funding LLC	27,361,641	27,789,112	28,645,860	28,218,389	21,136,115
5						
6	TOTAL ACCOUNT 233	237,361,641	907,789,112	708,645,860	38,218,389	23,688,517
7						
8	ACCOUNT 234 - ACCTS PAYABLE TO ASSOC CO					
9	CMS Bay Area Pipeline LLC	342,240	3,814,702	3,813,525	341,063	
10	CMS Electric & Gas LLC	601,782	0	0	601,782	
11	CMS Energy Corporation	21,636,405	278,003,475	257,448,193	1,081,123	
12	CMS Energy Resource Management Company	774,148	3,016,707	2,243,337	778	
13	CMS Enterprises Company	98,955	1,352,683	1,702,644	448,916	
14	CMS Gas Transmission Company	0	632	632	0	
15	CMS Generation Company	0	140,640	140,640	0	
16	CMS Land Company	0	71,625	71,625	0	
17	CMS Midland Holdings Company	0	23,369,159	23,369,159	0	
18	CMS Midland, Inc	0	181,891	181,891	0	
19	CMS Resource Development Company	0	1,901	1,901	0	
20	Consumers Campus Holdings LLC	0	1,515,573	1,518,140	2,567	
21	Consumers Funding LLC	(327,514)	49,898,330	50,090,543	(135,301)	
22	ES Services Company	131,968	1,735,949	1,819,054	215,073	
23	Genesse Power Station	2,428,768	15,946,667	15,953,653	2,435,754	
24	Grayling Generating Station	2,815,476	17,848,546	18,072,922	3,039,852	
25	Midland Cogeneration Venture	40,371,096	591,456,195	601,419,343	50,334,244	
26	T.E.S. Filer City Station	5,670,552	32,978,510	33,067,480	5,759,522	
27						
28	TOTAL ACCOUNT 234	74,543,876	1,021,333,185	1,010,914,682	64,125,373	
29						
30						
31						
32						
33						
34						
35						
36						
37						
38	Line 2 - Purpose: Working Capital					
39	Date of issue: 12-31-03, 12-31-04					
40	Maturity: 12-31-04, 12-31-05, Interest Rate: Variable					
41						
42	Line 3 - Purpose: Working Capital					
43	Date of issue: 12-30-03, 11-1-04					
44	Maturity: 12-29-04, 10-31-05, Interest Rate: Variable					
45						
46	Line 4 - Purpose: Securitization Bond Issuance					
47	Date of issue: 11-08-01					
48	Maturity: Various, Interest Rates: Various					
49						
50	It should be noted that column D may reflect					
51	activity in the accounts which includes estimates					
52						
53	TOTAL	311,905,517	1,929,122,297	1,719,560,542	102,343,762	23,688,517

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconcilation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as fas as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Imdicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income as if a separate return were to be filed, indicating, however, intercompany

Line No.			Total Amount
1	Utility net operating income (page 114 line 25)		
2	Allocations: Allowance for funds used during construction		
3	Interest expense		
4	Accretion expense		
5	Net income for the year (page 117 line 68)		279,073,567
6	Allocation of Net income for the year		
7			
8			
9	Add: Federal income tax expenses		151,100,032
10			
11			
12	Total pre-tax income		430,173,599
13			
14			
15	Add: Taxable income not reported on books		40,823,312
16			
17			
18	Add:Deductions recorded on books not deducted from return		641,331,554
19			
20			
21	Subtract: Income recorded on books not inlcuded in return		39,954,965
22			
23			
24	Subtract: Deductions on return not charged against book income		1,041,914,988
25			
26			
27	Federal taxable income for the year		30,458,512
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES (Continued)

amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. Allocate taxable income between utility and other income as required to allocate tax expense between 409.1 and 409.2
4. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions.

Utility	Other	Line No.
497,632,650		1
(24,834,253)		2
(244,197,514)		3
(592,234)		4
		5
227,702,649	51,370,918	6
		7
		8
122,913,649	28,186,383	9
		10
		11
350,616,298	79,557,301	12
		13
		14
40,467,861	355,451	15
		16
		17
638,667,225	2,664,329	18
		19
		20
31,618,086	8,336,879	21
		22
		23
1,015,264,987	26,650,001	24
		25
		26
(17,131,689)	47,590,201	27
		28
		29
		30
		31
		32
		33
		34
		35
		36
		37
		38

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

Line Ref.		Total Amount
11	Add: Taxable income not reported on books	
	CATV Pole Attachments - Def'd Revenue	177,408
	Clean Air Allowances - Revenue (now SO2)	541,844
	Contributions in Aid of Construction	23,433,273
	Interest Income	7,180,000
	Partnership Inc (Loss)	355,451
	Regulatory Contingency A	9,129,965
	Wurtsmith Escrow - Interest Income	5,371
		40,823,312
15	Add: Deductions recorded on books not deducted from return	
	Accrued Bonus - EICP Incentive	6,662,681
	AFUDC - Amortization Deficiency	306,830
	AFUDC - Generation	25,195,927
	AFUDC - Excess FERC Calc Rate	652,242
	ARO Transition/Accretion	549,030
	Bad Debt Reserve	443,336
	Charitable Contributions - CP Foundation Commitment	749,132
	Deferred Comp - Savings Plan - Rabbi Trust	11,685
	Deferred Compensation	130,915
	Depreciation - Book (Generation)	63,376,000
	Depreciation - Book (Includes Computer Software Depr)	263,626,000
	Electric Restructuring Costs - Line 26	3,334,020
	FAS 133 Electric Call Option - Accretion Exp	1,555,683
	Fly Ash Trust Fund	29,959
	Fly Ash Trust Fund - Interest Expense	6,015
	Injuries & Damages	8,976,074
	Interest During Construction (IDC) - Generation - Tax	16,167,000
	Interest During Construction (IDC) - Non-Generation - Tax	11,981,000
	Linepack Adjustment	1,316,127
	Lobbying and Political Contributions	1,692,000
	Meals & Entertainment - Nondeductible Portion	621,804
	Midland Amortization - FERC	518,516
	Nuclear Decommissioning - FERC - Palisades	304,894
	Nuclear Decommissioning - MPSC - Palisades	3,773,692
	Nuclear Fuel-Book Amortization	15,126,343
	OIL - Avoided Premim Surcharge	6,130,120
	OPEB - Def Service & Interest - Book Expense	30,149,313
	OPEB - Payments - 401H Contribution	7,055,695
	OPEB - Payments - Contribution Carryover	9,889,535
	OPEB - Transition Adj. Book Expense	23,178,604
	Outside Services-Accrued Auditing Expense	562,730
	Penalties	97,100
	Pensions (Including SERP) - Addback	24,353,929
	R&PP Tax-Book Exp Deducted on Prior Yr FIT Return (Addition)	63,074,000
	Sales & Use Tax Audit Exposure	4,400,000
	Securitized Assets - Book Amortization	42,242,881
	SEMP - Special Compensation	1,500,871
	SRO Retention	72,800
	Swap Agreements - Deferred Gain	599,071
	Vacation Pay Accrual	918,000
		641,331,554

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES		
		Line Ref.
		11
177,408	0	
541,844	0	
23,433,273	0	
7,180,000	0	
0	355,451	
9,129,965	0	
5,371	0	
40,467,861	355,451	
		15
6,662,681	0	
306,830	0	
25,195,927	0	
652,242	0	
549,030	0	
486,071	(42,735)	
0	749,132	
11,685	0	
130,915	0	
63,376,000	0	
263,626,000	0	
3,334,020	0	
1,555,683	0	
29,959	0	
6,015	0	
8,976,074	0	
16,167,000	0	
11,981,000	0	
1,316,127	0	
0	1,692,000	
621,804	0	
518,516	0	
304,894	0	
3,773,692	0	
15,126,343	0	
6,130,120	0	
30,149,313	0	
7,055,695	0	
9,889,535	0	
23,178,604	0	
562,730	0	
0	97,100	
24,353,929	0	
62,948,900	125,100	
4,400,000	0	
42,242,881	0	
1,500,871	0	
72,800	0	
555,339	43,732	
918,000	0	
638,667,225	2,664,329	

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

Line Ref.		Total Amount
19	Subtract: Income recorded on books not included in return	
	Bond Premium, Discount, Expense Amortization	20,336,562
	Campbell 3 Backup Capacity	68,957
	Equity Earnings in Subs	716,816
	Interest Income - Tax Exempt	7,180,000
	MCV Land Rent	18,895
	PSCR Underrecovery - 2004 Principle & Interest	3,241
	Regulatory Contingency A1 - Interest Expense	6,431,762
	Regulatory Contingency B	3,817,896
	SERP Interest Income - Book to Tax	1,127,178
	Service Programs (ASP/Housecall/Etc)	253,658
		39,954,965
23	Subtract: Deductions on return not charged against book income	
	263A Deduction Non- Inventory - Generation	30,133,000
	263A Deduction Non-Inventory - Non Generation	68,974,000
	Aetna/Blues Reserve	1,015,236
	AFUDC - Non Generation	218,477
	Cost of Removal - ADR Property - Generation	6,749,000
	Cost of Removal - ADR Property - Non Generation	4,452,000
	Depreciation - Tax (Generation)	39,523,000
	Depreciation - Tax (Includes Capitalized Computer Software Depr)	350,811,000
	DOE Decommissioning	1,585,154
	Gain/Loss on Disposition of ACRS Property - Generation - Tax	5,259,000
	Gain/Loss on Disposition of ACRS Property - Non-Generation - Tax	2,670,000
	Gas Inventory Adjustment	72,577,316
	Gas Inventory Adjustment - Hesson Storage	8,256,234
	Injuries & Damages - Environmental Clean-up	3,138,258
	Insurance Recovery - Manufactured Gas Plant (MGP) Sites	4,853,269
	Ludington Settlement - Line 2	1,456,735
	MCV Contract Loss - Line 26	26,432,364
	Nuclear Fuel Disposal - Dry Cask/Transportation System	2,081,396
	Nuclear Fuel-Tax Amortization	14,243,000
	OPEB - Medicare Subsidy - Tax Exempt	16,052,266
	OPEB - Payments - Key Employees	137,934
	OPEB - Payments - Tax	44,217,762
	PA 141 - Capital Expenditure - Return of	28,354,000
	PA 141 - Capital Expenditure - Return on	112,935,000
	PA 141 - Palisades & Big Rock Security	5,715,784
	PA 141 - Recoverable NOX Costs	3,201,875
	PA 141 - Recoverable SCR Equipment	418,528
	PA 141 - Recoverable Transmission Costs	2,812,343
	Pensions (Including SERP) - Deduction	5,018,345
	Preferred Stock Divident	671,672
	R&PP Tax-Book Change to Fiscal Yr Method - Adjustment	2,326,018
	R&PP Tax-Next Yr Exp Deducted in Current Yr (Deduction)	80,507,000
	Securitized Assets - Palisades Tax Depreciation	17,887,000
	Software - Non-capitalized Current Year Expenditures	13,583,000
	Stranded Costs	63,160,982
	Supplemental Pay-Special Retirement	487,035
	Rounding	5
		1,041,914,988

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES		
		Line Ref.
		19
20,294,334	42,228	
68,957	0	
0	716,816	
7,180,000	0	
0	18,895	
3,241	0	
0	6,431,762	
3,817,896	0	
0	1,127,178	
253,658	0	
31,618,086	8,336,879	
		23
30,133,000	0	
68,974,000	0	
1,015,236	0	
218,477	0	
6,749,000	0	
4,444,000	8,000	
39,523,000	0	
350,811,000	0	
1,585,154	0	
5,259,000	0	
2,670,000	0	
72,577,316	0	
8,256,234	0	
3,138,258	0	
4,853,269	0	
1,456,735	0	
0	26,432,364	
2,081,396	0	
14,243,000	0	
16,052,266	0	
137,934	0	
44,217,762	0	
28,354,000	0	
112,935,000	0	
5,715,784	0	
3,201,875	0	
418,528	0	
2,812,343	0	
5,018,345	0	
622,640	49,032	
2,324,418	1,600	
80,348,000	159,000	
17,887,000	0	
13,583,000	0	
63,160,982	0	
487,035	0	
0	5	
1,015,264,987	26,650,001	

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Name of Member of the Affiliated Group

CMS Energy Corporation
- Consumers Energy Company
  - CMS Engineering Co.
  - CMS Midland Holdings Company
  - CMS Midland, Inc.
  - Consumers EnergyGuard Services, Inc.
  - Consumers Nuclear Services LLC
  - ES Services Company
  - MEC Development Corp.
- CMS Enterprises Company
  - EnerBank USA
  - CMS Capital Financial Services, Inc.
  - Explotaciones CMS Oil and Gas Company
- CMS Land Company
- CMS Special Member Company
- CMS Energy Resource Management Corporation
  - CMS Texon Company
  - CMS Viron Corporation
- CMS Resource Development Company
- CMS Gas Transmission Company
  - CMS Midstream Services Company
- CMS Saginaw Bay Lateral Company
- CMS TriState Canada General Company
- CMS Generation Co.
  - CMS Generation Altoona Company
  - CMS Generation Chateaugay Company
  - CMS Generation Filer City, Inc.
  - CMS Generation Filer City Operating Company
  - CMS Generation Genesee Company
  - CMS Generation Grayling Company
  - CMS Generation Grayling Holdings Company
  - CMS Generation Holdings Company
  - CMS Generation Honey Lake Company
  - CMS Generation Lyonsdale Company
  - CMS Generation Montreal Company
  - CMS Generation Operating Company
  - CMS Generation Recycling Company
  - Exeter Management Company
  - Hydra-Co Enterprises, Inc.
    - CMS Generation Operating Company II, Inc.
      - HCO - Jamaica, Inc.
    - CMS Generation Stratton Company
    - HCE - Appomattox, Inc.
    - HCE - Biopower, Inc.
    - HCE - Jamaica Development, Inc.
    - HCE - Rockfort Diesel, Inc.
    - Hydra-Co Generation, Inc.
    - New Bern Energy Recovery, Inc.
    - Oxford Tire Recycling, Inc.
    - Oxford Tire Supply, Inc.
    - Taweelah A2 Operating Co.

Consolidated federal income taxes are allocated to each member of the affiliated group based on each separate Company's taxable income. Tax benefits realized from filing a consolidated return are allocated to the company generating the benefit. For 2004, current federal income tax expense is allocated as follows:

	In thousands
Consumers Energy Company	$ 14,094
All other members of the group	$ (14,094)
CMS Energy Consolidated	$ -

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (a)	BALANCE AT BEGINNING OF YEAR Taxes (1) Accrued (Acct 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (165) (c)	Taxes Charged During Year (d)	Paid (2) During Year (e)	Adjust-ments (f)	BALANCE AT END OF YEAR Taxes Accrued (Acct 236) (g)	BALANCE AT END OF YEAR Prepaid Taxes (165) (h)
1	--FEDERAL--							
2	Income (A)	(47,772,804)		14,093,641	49,801,643	(15,175)	16,107,305	
3	Unemployment (B)	0		462,517	(445,176)	0	17,341	
4	FICA (B)	(445,634)		40,834,463	(38,858,599)	0	1,530,230	
5								
6	TOTAL FEDERAL	(48,218,438)	0	55,390,621	10,497,869	(15,175)	17,654,876	0
7								
8	--STATE--							
9	Income (A)	0		3,361	(3,111)	0	250	
10	Unemployment (B)	0		1,392,115	(1,339,921)	0	52,194	
11	MI Single Business Tax (A)	25,604,058		18,123,936	(26,186,635)	(180,632)	17,360,727	
12	MPSC Assessment (E)	0	(1,355,731)	4,430,067	(4,539,517)	0	0	(1,465,182)
13	Surplus Lines Premium Tax		0	4,193	(4,193)	0		0
14	State Sales&Use Tax Absorbed By Co (C)	3,000,000		4,653,838	(253,838)	(0)	7,400,000	
15								
16	TOTAL STATE	28,604,058	(1,355,731)	28,607,510	(32,327,216)	(180,632)	24,813,171	(1,465,182)
17								
18	--LOCAL--							
19	Real & Personal Property (D)	222,037,133		138,441,997	(139,741,951)	4,726,018	225,463,197	
20	City Income Tax (A)	(83,800)		0	60,000	(0)	(23,800)	
21								
22	TOTAL LOCAL	221,953,333	0	138,441,997	(139,681,951)	4,726,018	225,439,397	0
23								
24								
25	Account 236 Reconciliation							
26								
27								
28	TOTAL	202,338,954	(1,355,731)	222,440,128	(161,511,298)	4,530,212	267,907,444	(1,465,182)

(1) Federal Income Tax balances include MPSC accounts 244 and 245.

(2) Column (e) - Federal Income and Michigan Single Business Tax payments flow through intercompany accounts to the parent.

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and state income taxes) covers more than one tax year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Enter accounts to which taxes charged were distributed in columns (i) thru (l). In column (i), report the amounts charged to Accounts 408.1 and 409.1 for Electric Dept. only. Group the amounts charged to 408.1, 409.1, 408.2 and 409.2 under other accounts in column (l). For taxes charged to other accounts or utility plant, show the number of the appropriate balance sheet account, plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state the basis (necessity) of apportioning such tax.
10. Fill in all columns for all line items.

DISTRIBUTION OF TAXES CHARGED (Omit Cents) (Show utility department where applicable and account charged)

Line No.	Electric a/c 408.1 409.1 (i)	Gas a/c 408.1 409.1 (j)	Other Utility Departments a/c 408.1,409.1 (k)	Other Income & Deductions a/c 408.2,409.2 (l)	Plant Account Charged a/c 107 (m)	Transport Clearing a/c 184 (n)	Miscellaneous Clearing and Other Sources (o)	Other (p)
1								
2	(20,432,643)	7,189,996	0	27,336,288	0	0	0	0
3	199,845	105,547	0	0	132,910	0	24,214	0
4	17,643,870	9,318,482	0	0	11,734,319	0	2,137,793	0
5								
6	(2,588,928)	16,614,025	0	27,336,288	11,867,229	0	2,162,007	0
7								
8								
9	0	0	0	3,361	0	0	0	0
10	601,509	317,683	0	0	400,043	0	72,881	0
11	12,197,757	5,110,906	0	72,245	0	0	743,028	0
12	2,725,780	1,704,287	0	0	0	0	0	0
13		4,193						
14	3,599,457	1,054,381	0	0	0	0	0	0
15								
16	19,124,503	8,191,450	0	75,606	400,043	0	815,909	0
17								
18								
19	102,196,512	35,950,524	0	294,962	0	0	0	0
20	0	0	0	0	0	0	0	0
21								
22	102,196,512	35,950,524	0	294,962	0	0	0	0
23								
24								
25								
26								
27								
28	118,732,087	60,755,998	0	27,706,856	12,267,272	0	2,977,915	0

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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR - Footnotes

Instruction 6. - Adjustments Column (f)

FEDERAL INCOME TAX (line 6):	
1. Adjustment to reduce the accrued tax liability for excise tax paid on nonhighway use gasoline.	(15,175)
TOTAL (Ties to Line 6)	(15,175)
STATE (line 16):	
1. Michigan Single Business Tax - WDSB Workmans Comp Supplemental Fund Credits to 143 account.	(180,632)
TOTAL (Ties to Line 16)	(180,632)
LOCAL (line 22):	
1. Adjustment to reflect increase (decrease) in 2003 estimated property tax over 2002 property tax estimate.	2,400,000
2. Real and Personal Property Tax fiscal year adjustments to 174 account.	2,326,018
TOTAL (Ties to Line 22)	4,726,018
TOTAL ADJUSTMENTS (Line 28)	4,530,212

Instruction 9. - Basis of Allocation

See Page 262, Column (a) for taxes to which basis is applied.

Allocation Basis

(A) Taxable Net Income Basis
(B) Amount of Payroll Charged to Departments
(C) Customer Basis
(D) Taxable Assets Basis
(E) Gross Operating Revenue Basis

Other

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Actual use taxes paid to the State on purchases were $4,308,959 for 2004.

Line 26 - Account 236 Reconciliation

MPSC Account 236 ending balance	267,907,444

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%	57,896			411.4	38,510	
3	4%	8,302,080			411.4	434,493	
4	7%						
5	10%	45,581,032			411.4	2,491,767	
6							
7							
8	TOTAL	53,941,008				2,964,770	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Utility						
11	3%	199,471			411.4	76,510	
12	4%	1,107,213			411.4	44,840	
13	7%	672,740			411.4	86,873	
14	10%	17,137,335			411.4	655,435	
15							
16	Total Gas	19,116,759				863,658	
17							
18							
19							
20							
21							
22							
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48							

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2004/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
19,386	34 years		2
7,867,587	37 years		3
			4
43,089,265	34 years		5
			6
			7
50,976,238			8
			9
			10
122,961	37 years		11
1,062,373	32 years		12
585,867	34 years		13
16,481,900	32 years		14
			15
18,253,101			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
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			48

MISCELLANEOUS CURRENT AND ACCRUED LIABILITIES (Account 242)

1. Give description and amount of other current and accrued liabilities as of the end of year.
2. Minor items may be grouped by classes, showing number of items in each class.

Line No.	Item (a)	Balance End of Year (b)
1	Electric Call Options Payable	7,404,172
2	OPEB Current Obligations	25,198,459
3	Employee Incentive Compensation Plan	14,954,203
3	Accrued Vacation Liability	10,331,639
4	Estimated Cost of Purchased Power	12,193,806
5	Margins Deposits - Electric	1,850,000
6	Healthcare and Life Insurance Accruals	4,283,014
7	Other Miscellaneous Liabilities (6 Items)	637,956
8	Special Retirement Supplements	1,800,243
9	Environmental Clean-up (34 Sites)	2,276,406
10	DOE Decontamination & Decommissioning Fund - Current	2,611,398
11	Ludington Fish Settlement	113,198
12	Customer Deposits	951,714
13	Hydro Plant Fish Compensation	1,103,526
14	Transformer Failure	845,000
15	Peoplecare - Customer Contribution	38,751
16	Employee Retention Liabilities	1,455,200
17	Hydro and Ludington FERC fees	768,190
18	Accrued Audit Fees	996,574
19	CE Foundation	1,000,000
20	Deferred Employee Compensation	15,432,372
21	Miscellaneous Payroll Deductions (10 Items)	12,067
22		
23		
24		
25		
26		
27		
34		
35		
36		
37		
38	Total	106,257,888

CUSTOMER ADVANCES FOR CONSTRUCTION (Account 252)

Line No.	List Advances by Departments (a)	Balance End of Year (b)
1	Electric	33,394,694
2	Gas	109,112
3	Total	33,503,806

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (less than $10,000) may be grouped by classes.

Line No.	Description of Other Deferred Credit (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Unclaimed Checks - Various	441,935	232	918,000	1,512,964	1,036,899
2	DOE Decommissioning of Enrichment Facility	4,264,086	242	2,678,931	1,026,244	2,611,399
3	Environmental Clean-Up Manufactured Gas	43,942,695	182	6,080,700		37,861,995
4	Adrian Energy Performance Contingency	256,308	242	0	30,793	287,101
5	Electric Contingency Reserve	30,718,655	Various	2,170,160	18,409,857	46,958,352
6	Transmission Relocation Advance	1,205,009	107	555,285	517,389	1,167,113
7	Backup Capacity Agreement - Campbell 3	1,654,372	447	3,031,487	2,962,530	1,585,415
8	Directors Deferred Compensation Plans	1,105,214	232	33,269	298,493	1,370,438
9	Executive, Deferred Compensation Plans	4,459,733	232	9,357,283	9,238,649	4,341,099
10	Intercompany MCV Income (1)	401,526	418	18,896	0	382,630
11	Consumers Energy Foundation Commitments	964,443	426	214,894	0	749,549
12	Adv Pymt -Billed Costs	527,434	172/143	915,900	775,161	386,695
13	OIL Insur limited-Premium Liability	0			6,130,120	6,130,120
14	Undistr Insurance-Aetna	0			20,782	20,782
15	Cash Receipts	38,463	Various	290,075,825	290,043,479	6,117
16	Insurance Recovery - MGP	21,721,326	131/925	4,899,865	229,462	17,050,923
17	Deferred ASP Revenue- Gas	923,042	488	410,967	157,309	669,384
18	Elec Call Options-Noncurr	14,558,935	242	8,808,591	2,930,400	8,680,744
19	Gas Contingency	3,738,352	Various	6,000,254	2,182,358	(79,544)
20	Deferred Interest - Escrow Agreements	820,716		0	1,877,248	2,697,964
21	Interconnection Advances	367,523	107	2,289,321	2,851,000	929,202
22	Deferred Lease Revenue - METC	2,510,325	454	10,041,000	7,530,675	0
23	Electric Generation Supplier Deposits	2,773,517	131	2,773,517	2,816,203	2,816,203
24	MGS Refund (Pepl)	0		0	96,821	96,821
25	Financial Solutions-Defd Rev	106,448	131/454	97,308	82,848	91,988
26	Deferred Rev - Pole Attachments	1,504,865	454	3,470,192	3,647,603	1,682,276
27	Gas Options	599,821	175\421	13,954,829	14,311,780	956,772
28	Reserve Capacity Def Rev 2004	0			340,609	340,609
29	Northville Base Gas/Storage	246,825	101	365,007	287,544	169,362
30	Deferred Employee Compensation	7,271,498	242	15,589,368	8,317,870	0
31	MiJuns Membership Fees	30,666	131	34,101	28,750	25,315
32	FAMS Project	524,111	131	111,900	19,140	431,351
33	FAS-143 ARO Liability	358,120,376	108	84,028,797	162,015,245	436,106,824
34	Minor (2 Items - less than $10,000)	3,893	Various	1,160,655	1,160,383	3,621
35	(1) 35 Year Amortization Ending 2025					
36						
37						
38						
39	TOTAL	505,802,112		470,086,302	541,849,709	577,565,519

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	804,908,278	74,521,885	30,669,814
3	Gas	284,658,127	33,562,236	12,023,386
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,089,566,405	108,084,121	42,693,200
6				
7	Non-Utility	1,236,232		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,090,802,637	108,084,121	42,693,200
10	Classification of TOTAL			
11	Federal Income Tax	1,090,802,637	108,084,121	42,693,200
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
		190;282	12,016,228	190;282	11,483,401	848,227,522	2
		190	415,916	282	2,038	305,783,099	3
							4
			12,432,144		11,485,439	1,154,010,621	5
							6
4,594	5,709	282	4,594			1,230,523	7
							8
4,594	5,709		12,436,738		11,485,439	1,155,241,144	9
							10
4,594	5,709		12,436,738		11,485,439	1,155,241,144	11
							12
							13

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to accounts relating to accounts recorded in Account 283.
2. For Other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	AFUDC (U-8638)	961,199	0	42,435
4	Bond Premium, Discount & Expense Amortized	13,425,506	6,825,429	1,751,521
5	Construction Overheads (FPC 530/MPSC U-5281)	632,084	0	31,608
6	DOE Decommissioning	(129)	0	0
7	Other (See Line 24, Page 276A)	413,402,665	113,120,632	49,525,274
8	TOTAL Electric (Enter total of lines 3 thru 8)	428,421,325	119,946,061	51,350,837
9	Gas			
10	AFUDC (U-8638)	(4,449)	0	572
11	Bond Premium, Discount & Expense Amortized	4,009,385	2,578,068	619,451
12	Other (See Line 60, Page 276B)	249,256,814	39,730,199	13,870,477
13	TOTAL Gas (Enter total of lines 11 thru 16)	253,261,750	42,308,267	14,490,499
14	TOTAL Other (Specify) (See Line 76, Page 276B)	49,303,245	0	0
15	TOTAL Account 283 (Enter total of lines 9, 17 & 18)	730,986,320	162,254,328	65,841,337
16	Classification of TOTAL			
17	Federal Income Tax	730,986,320	162,254,328	65,841,337
18	State Income Tax	-	-	-
19	Local Income Tax	-	-	-

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283) (Cont.)

3. Provide in the space below explanations for Pages 276 and 277. Include amounts relating to insigificant items under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						918,764	3
						18,499,414	4
						600,476	5
						(129)	6
0	0		4,516,144		6,866,589	474,647,578	7
0	0		4,516,144		6,866,589	494,666,103	8
							9
						(5,021)	10
						5,968,002	11
			0		14,395,388	260,721,149	12
0	0		0		14,395,388	266,684,130	13
997,830	931,624		3,531,722		0	52,901,172	14
997,830	931,624		8,047,866		21,261,977	814,251,405	15
							16
997,830	931,624		8,047,866		21,261,977	814,251,405	17
-	-		-		-	-	18
-	-		-		-	-	19

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283) (Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
20	Electric Other (Detail of line 8):			
21	AFUDC Excess FERC - Electric	85,135	112,555	426,502
22	Brownfield Credit - MSBT	0	1,514,771	0
23	Electric Restructuring Implementation Project (ERIP)	28,585,446	1,876,052	2,190,526
24	FAS133-Call Options	243,994	0	0
25	FAS133-Fuel Options	(13,035)	654,965	0
26	Greenpower Reprogram Costs	108,841	18	0
27	Ludington Settlement	(603,829)	1,062,314	552,457
28	Midland Amort - FERC (U-8776)	2,818,256	0	140,913
29	N/F Dry Cask Storage/Transportation System	17,172,792	2,112,872	0
30	OPEB Regulatory Asset	40,703,996	0	5,913,568
31	PA 141 Sec 10(D)3 Capital Expend-Return of	0	9,923,900	0
32	PA 141 Sec 10(D)3 Capital Expend-Return on	0	39,527,250	0
33	PA 141 Sec 10(D)3 Costs-Palisades Security	2,002,194	2,027,833	27,309
34	PA 141 Sec 10(D)3 Costs-Recoverable SCR Equipment	0	134,615	(11,870)
35	PA 141 Sec 10(D)3 Costs-Recoverable NOX Costs	0	1,120,657	0
36	PA 141 Sec 10(D)3 Costs-Recoverable Transmission Cost	0	984,321	0
37	Potential Audit Deficiency	534,692	0	0
38	Prepaid Pension Expense	92,647,078	111,146	5,824,511
39	PSCR Underrecovery (U-10445)	64,665	0	(1,135)
40	Real & Personal Property Taxes (U-5584)	31,500,473	21,961,724	16,750,944
41	Securitized Regulatory Assets	186,166,544	6,260,450	16,735,459
42	Stranded Costs	0	22,106,344	0
43	Reg Asset-Transmission Assets	10,451,742	1,628,844	570,000
44	Sec 263A Adj Fuel Supply Inventory	376,137	0	406,089
45	SFAS 109 - Accumulated DFIT Liab - Midland Abandonment	557,545	0	0
46	Total Electric Other	413,402,665	113,120,632	49,525,274

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283) (CONTINUED)

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							20
		282.110				(228,812)	21
						1,514,771	22
						28,270,972	23
		219.xxx				243,994	24
				190.162	641,930	0	25
						108,859	26
						(93,972)	27
						2,677,343	28
		190002	1,547,500			20,833,164	29
		283101	2,968,644	190185/283174	4,586,855	33,172,216	30
						9,923,900	31
						39,527,250	32
						4,002,718	33
						146,485	34
						1,120,657	35
						984,321	36
						534,692	37
		190.065				86,933,713	38
		190.071				65,800	39
						36,711,253	40
						175,691,535	41
						22,106,344	42
				192.102	1,628,844	9,881,742	43
		282.111				(29,952)	44
				192.100	8,960	548,585	45
0	0		4,516,144		6,866,589	474,647,578	46

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283) (Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
47	Gas Other (Detail of Line 16)			
48	AFUDC Excess FERC - Gas	(39,794)	6,450.00	28,178.99
49	Brownfield Credit - MSBT	-	1,290,360.00	0.00
50	Customer Choice-Deferred Expense	206,637	0	0
51	Gas Inventory Adjustment	100,214,718	25,402,061	0
52	Hesson Gas Storage Field Inventory Adj	-	2,889,682	0
53	I&D MGP - Environmental Remediation	7,120,173	2,264,199	60,509
54	Manufactured Gas Plants Environmental Clean-up	26,872,194	0	0
55	OPEB Regulatory Asset	33,075,985	0	4,668,438
56	Potential Audit Deficiency	534,692	0	0
57	Prepaid Pension Expense	41,624,049	49,935	2,728,239
58	Real & Personal Property Taxes (U-5584)	12,020,852	7,827,512	6,385,112
59	Take or Pay Order 500	27,627,308	0	0
60	Total Gas Other	249,256,814	39,730,199	13,870,477
61				
62	Other (Detail of line 18):			
63	Bond Premium, Discount & Expense Amortized	2,904,537		
64	Dow Chemical (U-8448)	1,002,022		
65	FAS 115 - CMS Stock	3,395,851		
66	FAS 115 - Nuclear Decommissioning	36,859,151		
67	FAS 115 - SERP	1,452,790		
68	Marysville Deferred Gain - Basis	3,666,964		
69	Midland Abandonment Allocated to Bechtel (U-9096)	(519,247)		
70	Midland Demobilization (U-8448)	6,667		
71	Midland Land (U-9096)	9,425		
72	Real & Personal Property Taxes (U-5584)	117,028		
73	SERP Plan Assets-Interest Income	408,056		
74	Total Other	49,303,245	0	0

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283) (CONTINUED)

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							47
				282.112		(61,523)	48
						1,290,360	49
						206,637	50
						125,616,779	51
						2,889,682	52
						9,323,863	53
				190.137	13,620,495	13,251,699	54
		190.089		190186	774,893	27,632,655	55
						534,692	56
		190066				38,945,745	57
						13,463,253	58
						27,627,308	59
0	0		0		14,395,388	260,721,149	60
							61
							62
639,009.00	610,117					2,933,429	63
0	0					1,002,022	64
0	0	219.002	1,594,645			4,990,497	65
0	0	190.141-2/152	1,517,329			38,376,480	66
0	0	219.004	419,747			1,872,537	67
0	275,555					3,391,409	68
0	0					(519,247)	69
0	0					6,667	70
0	0					9,425	71
56,764	45,952					127,840	72
302,057	0					710,113	73
997,830	931,624		3,531,722		0	52,901,172	74

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Clean Air Allowances EPA Auction Sales	541,844				541,844
2	SFAS 109 Regulatory Liability	354,555,734			31,135,530	385,691,264
3	Gain on Sale of METC	3,850,000				3,850,000
4	AFUDC Deficient from FERC Rate	1,138,693	421	874,755	299,881	563,819
5	FAS 143 ARO Liability	154,735,931	108/230/411	7,851,104	21,579,186	168,464,013
6						
7						
8						
9						
10						
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37						
38						
39						
40						
41	TOTAL	514,822,202		8,725,859	53,014,597	559,110,940

GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421.2)

1. Give a brief description of property creating the gain or loss. Include name of party acquiring the property (when acquired by another utility or associated company) and the date transaction was completed. Identify property by type; Leased, Held for Future Use, or Nonutility.
2. Individual gains or losses relating to property with an original cost of less than $100,000 may be grouped, with the number of such transactions disclosed in column (a).
3. Give the date of Commission approval of journal entries in column (b), when approval is required. Where approval is required but has not been received, give explanation following the item in column (a). (See Account 102, Utility Plant Purchased or Sold.)

Line No.	Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Account 421.1 (d)	Account 421.2 (e)
1	Gain on disposition of property:				
2					
3	UTILITY LAND SALES -- 83 sales under $100,000				
4	original cost.	42,364		1,135,954	
5					
6	UTILITY LAND SALES - original cost > $100,000				
7	Kent 556	232,235		346,765	
8	Kent 557	135,403		50,000	
9					
10	NON-UTILITY LAND SALES -- 5 sales with original				
11	cost < $100,000	2,229		21,728	
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32	Total gain	412,230		1,554,447	

GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421.2) (continued)

Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Account 421.1 (d)	Account 421.2 (e)	Line No.
Loss on disposition of property:					1
					2
UTILITY LAND SALE S - 190 sales under $100,000 original cost.	312,974			377,175	3 4
					5
UTILITY LAND SALES - original cost > $100,000					6
Oakland 204	184,035			184,035	7
Oakland Co	183,106			183,106	8
					9
NON UTILITY LAND SALES -- 13 sales under $100,000 original cost.	51,850			49,380	10 11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
Total loss	731,964			793,696	32

PARTICULARS CONCERNING CERTAIN OTHER INCOME ACCOUNTS

1. Report in this schedule the information specified in the instructions below for the respective other income accounts. Provide a conspicious subheading for each account and show a total for the account. Additional columns may be added for any account if deemed necessary.

2. Merchandising, Jobbing and Contract Work (Accounts 415 and 416) - Describe the general nature of merchandising, jobbing and contract activities. Show revenues by class of activity, operating expenses classified as to operation, maintenance, depreciation, rents and net income before taxes. Give the bases of any allocations of expenses between utility and merchandising, jobbing and contract work activities.

3. Nonutility Operations (Accounts 417 and 417.1) - Describe each nonutility operation and show revenues, operating expenses classified as to operation, maintenance, depreciation, rents, amortization, and net income before taxes, from the operations. Give the bases of any allocations of expenses between utility and nonutility operations. The book cost of property classified as nonutility operations should be included in Account 121.

4. Nonoperating Rental Income (Account 418) - For each major item of miscellaneous property included in Account 121, Nonutility Property, which is not used in operations for which income is included in Account 417, but which is leased or rented to others, give name of lessee, brief description of property, effective date and expiration date of lease, amount of rent revenues, operating expenses classified as to operation, maintenance, depreciation, rents, amortization, and net income, before taxes, from the rentals. If the property is leased on a basis other than that of a fixed annual rental, state the method of determining the rental. Minor items may be grouped by classes, but the number of items so grouped should be shown. Designate any lessees which are associated companies.

5. Equity in earnings of subsidiary companies (Account 418.1) - Report the utility's equity in the earnings or losses of each subsidiary company for the year.

6. Interest and Dividend Income (Account 419) - Report interest and dividend income, before taxes, identified as to the asset account or group of accounts in which are included the assets from which the interest or dividend income was derived. Income derived from investments, Account 123, 124 and 136 may be shown in total. Income from sinking and other funs should be identified with the related special funds. Show also expenses included in Account 419 as required by the Uniform System of Accounts.

7. Miscellaneous Nonoperating Income (Account 421) - Give the nature and source of each miscellaneous nonoperating income, and expense and the amount for the year. Minor items may be grouped by classes.

Line No.	Item (a)		Amount (b)
1	REVENUE FROM MERCHANDISING, JOBBING AND CONTRACT WORK - ACCOUNT 415		
2	Gas Fuel Line Installation	485,019	
3	Joint Trench Revenue	13,780,660	
4	Michigan Electric Transmission Company Revenue	28,020,828	
5	Gas Meters Covers	26,307	
6	Water Meter Reading	317,802	
7	Lab Commercial Services\Calibration and Analytical Testing	1,001,798	
8	Gas T&S Operation\Maintenance of Third Party Equipment	1,028,890	
9	other	142,140	
10	TOTAL		44,803,444
11			
12	COSTS AND EXPENSES OF MERCHANDISING, JOBBING AND CONTRACT WORK - ACCOUNT 416		
13	Gas Fuel Line Installation	(329,625)	
14	Joint Trench Expense	(11,694,636)	
15	Michigan Electric Transmission Company Expense	(22,843,007)	
16	Gas Meters Covers	(13,231)	
17	Water Meter Reading Expense	(305,733)	
18	Lab Commercial Services\Calibration Analytical Testing Expense	(952,038)	
19	Gas T&S Operation/Maintenance of Third Party Equipment Expense	(553,669)	
20	Other	(69,738)	
21	TOTAL		(36,761,677)
22			
23	REVENUES AND EXPENSES RELATING TO NONUTILITY OPERATIONS - ACCOUNTS 417 AND 417.1		
24	Revenues	1,854,296	
25	Expenses	(1,708,413)	
26	Total Revenues and Expenses Relating to Nonutility Operations		145,883
27			
28	NONOPERATING RENTAL INCOME - ACCOUNT 418		
29	Revenue From Various Nonutility Property Leases & Other Rental Items -	29,051	
30	Approximately 23 Parties		
31	MCV - (Assoc Co)		
32	Land Lease	450,000	
33	Amortization	18,895	
34	Total Non Operating Income		497,946
35			
36	EQUITY EARNINGS IN SUBSIDIARY COMPANIES - ACCOUNT 418.1		
37	ES Services Co.	(52,364)	
38	CMS Engineering	(18,532)	
39	CMS Midland, Inc.	(8,206,392)	
40	CMS Midland Holdings	9,220,459	
41	CE Finance I-IV	1,411,474	
42	Campus Holdings	(9,804)	
43			
44			

PARTICULARS CONCERNING CERTAIN OTHER INCOME ACCOUNTS (Continued)

Line No.	Item (A)		Amount (b)
41	EQUITY EARNINGS IN SUBSIDIARY COMPANIES-ACCOUNT 418.1 CONTINUED		
42	CE Nuclear Services	(216,551)	
43	Total Equity Earnings in Subsidiary Companies		2,128,290
44			
45	INTEREST AND DIVIDEND INCOME - ACCOUNT 419		
46	WPS Secured Borrowing -Account 141	1,061,703	
47	Investments Included in Accounts 123, 124 & 136	1,585,529	
48	Notes and Accounts Receivable	767,520	
49	Interest Income - Associated & Subsidiary Companies-Account 146	160,370	
50	SERP Interest-Account 128	1,505,992	
51	Other	642,531	
52	Total Interest and Dividend Income		5,723,645
53			
54			
55			
56	ALLOWANCE FOR OTHER FUNDS USED DURING CONSTRUCTION - ACCOUNT 419.1		(143,197)
57			
58	MISCELLANEOUS NONOPERATING INCOME - ACCOUNT 421		
59	Royalties and Working Interest From Oil and Gas Leases	834,120	
60	Software writeoff	(1,720,947)	
61	Cost of Money - Electric Restructuring	6,196,880	
62	AFUDC	(810,704)	
63	Bill Payment Fees	305,206	
64	PA 141 : Return on Capital Exp	112,935,000	
65	Return on Security Costs	1,986,050	
66	Return on Stranded Costs	6,908,887	
67	Other	27,569	
68	Total Miscellaneous Nonoperating Income		126,662,061
69			
70			
71			
72			
73			
74	GAIN ON DISPOSITION OF PROPERTY - ACCOUNT 421.1		
75	See Page 280A for details		1,554,447
76			
77	LOSS ON DISPOSITION OF PROPERTY - ACCOUNT 421.2		
78	See Page 280A for details		(793,696)
79			
80			
81			
82			
83			
84			
85			
86			
87			
88			
89			
90			
91			
92			
93			
94			
95			
96			
97			
98			
99			
100			
101	Total Other Income		143,817,146

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	996,750,374	1,005,246,998
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	817,839,440	826,733,863
5	Large (or Ind.) (See Instr. 4)	527,064,400	562,252,314
6	(444) Public Street and Highway Lighting	23,063,179	22,597,782
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	3,179,000	3,170,081
10	TOTAL Sales to Ultimate Consumers	2,367,896,393	2,420,001,038
11	(447) Sales for Resale	115,757,563	75,698,488
12	TOTAL Sales of Electricity	2,483,653,956	2,495,699,526
13	(Less) (449.1) Provision for Rate Refunds	3,792,355	7,452,599
14	TOTAL Revenues Net of Prov. for Refunds	2,479,861,601	2,488,246,927
15	Other Operating Revenues		
16	(450) Forfeited Discounts	8,967,526	9,560,449
17	(451) Miscellaneous Service Revenues	2,378,060	2,016,068
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	21,472,797	22,688,028
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	30,099,090	21,398,332
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	62,917,473	55,662,877
27	TOTAL Electric Operating Revenues	2,542,779,074	2,543,909,804

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

ELECTRIC OPERATING REVENUES (Account 400)

5. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
12,346,200	12,462,333	1,542,527	1,530,540	2
				3
10,785,207	11,161,411	208,015	200,148	4
9,677,929	10,382,772	8,576	8,795	5
181,710	180,565	1,762	1,914	6
				7
				8
48,272	51,889			9
33,039,318	34,238,970	1,760,880	1,741,397	10
2,941,428	1,771,417	4	10	11
35,980,746	36,010,387	1,760,884	1,741,407	12
				13
35,980,746	36,010,387	1,760,884	1,741,407	14

Line 12, column (b) includes $ -12,964,156 of unbilled revenues.

Line 12, column (d) includes -224,666 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL					
2						
3	A-1 RESIDENTIAL SERVICE	11,809,096	948,207,445	1,433,574	8,238	0.0803
4	A-3 TIME-OF-DAY FARM & SH	44,113	3,049,701	1,514	29,137	0.0691
5	A-4 ALTERNATE RESIDENCE	301,417	30,804,153	95,753	3,148	0.1022
6	A-5 FARM	262,548	20,027,675	11,687	22,465	0.0763
7	UNBILLED REVENUE	-70,974	-5,341,699			0.0753
8	RENEWABLE ENERGY					
9	PLANNED LOAD MGMNT					
10	SECURITIZATION SAVINGS RES					
11	ERIP					
12	SECURITY RECOVERY		3,102			
13	DIRECTLY CREDITED TO 44X		-3			
14						
15	TOTAL RESIDENTIAL	12,346,200	996,750,374	1,542,528	8,004	0.0807
16						
17						
18	COMMERCIAL					
19						
20	B-GENERAL SECONDARY	2,309,292	237,748,524	169,647	13,612	0.1030
21	C-GENERAL SECONDARY	4,327,140	325,944,567	25,397	170,380	0.0753
22	B-1 GENERAL PRIMARY SERV	213,845	18,205,111	427	500,808	0.0851
23	D-PRIMARY SERVICE	2,602,098	155,257,577	1,069	2,434,142	0.0597
24	F-PRIMARY HI-LOAD FACTOR	445,436	23,725,630	115	3,873,357	0.0533
25	GH-ELECTRIC HEATING SERV	43,085	3,812,917	1,364	31,587	0.0885
26	H-WATER HEATING SERVICE	5,924	474,596	564	10,504	0.0801
27	R-1 SECONDARY RESALE	299	25,502	6	49,833	0.0853
28	R-2 SECONDARY RESALE	8,874	644,866	23	385,826	0.0727
29	R-3 PRIMARY RESALE SERV	246,813	14,586,436	60	4,113,550	0.0591
30	UR-UNMETERED SERVICE	100,114	5,917,466	423	236,676	0.0591
31	PS-1 SECONDARY PUBLIC	64,833	5,113,836	3,250	19,949	0.0789
32	PS-2 PRIMARY PUBLIC PUMP	77,760	5,056,672	324	240,000	0.0650
33	PS-3 OPT PRIMARY PUBLIC	379,897	18,950,840	116	3,274,974	0.0499
34	L-4 COM OUTDOOR LIGHTING	15,329	2,374,326	5,230	2,931	0.1549
35	UNBILLED REVENUE	-72,980	-3,822,537			0.0524
36	RENEWABLE ENERGY					
37	PLANNED LOAD MGMNT		-697,250			
38	SECURITIZATION SAVINGS RES		-3,054,000			
39	ERIP		4,135,441			
40	SECURITY RECOVERY		431,774			
41	TOTAL Billed	33,263,947	2,374,857,776	1,760,882	18,891	0.0714
42	Total Unbilled Rev.(See Instr. 6)	-224,629	-13,069,383	0	0	0.0582
43	TOTAL	33,039,318	2,361,788,393	1,760,882	18,763	0.0715

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	SPEC CONTRACT DISC COMM		-999,763			
2	DIRECTLY CREDITED TO 44X		-1			
3						
4	TOTAL COMMERCIAL	10,767,759	813,832,530	208,015	51,764	0.0756
5						
6						
7	INDUSTRIAL					
8						
9	B-GENERAL SECONDARY	313,194	30,805,835	5,531	56,625	0.0984
10	C-GENERAL SECONDARY	648,923	50,479,074	1,583	409,932	0.0778
11	CG-COGEN & SMALL POWER	30,392	1,636,246	9	3,376,889	0.0538
12	B-1 GENERAL PRIMARY SERVICE	175,895	14,402,218	317	554,874	0.0819
13	D-PRIMARY SERVICE	4,334,078	249,564,063	863	5,022,107	0.0576
14	F-PRIMARY HI-LOAD FACTOR	759,167	35,752,503	23	33,007,261	0.0471
15	GH-ELECTRIC HEATING SERV	511	45,522	21	24,333	0.0891
16	H-WATER HEATING SERVICE	16	1,535	4	4,000	0.0959
17	I-PRIMARY INTERRUPTIBLE	15,630	747,417	1	15,630,000	0.0478
18	J-PRIMARY ELECE FURNACE	64,987	3,493,527	10	6,498,700	0.0538
19	J-1 ALTERNATE METAL MELT	311,464	14,257,486	6	51,910,667	0.0458
20	R-3 PRIMARY RESALE SERV	390	34,992			0.0897
21	L-4 IND OUTDOOR LIGHTING	823	119,817	182	4,522	0.1456
22	SPECIAL CONTRACTS	3,120,286	127,483,671	28	111,438,786	0.0409
23	UNBILLED REVENUE	-80,379	-3,860,774			0.0480
24	RENEWABLE ENERGY		23,955			
25	PLANNED LOAD MGMNT		-960,997			
26	SECURITIZATION SAVINGS RES		-3,054,000			
27	ERIP		3,410,284			
28	SECURITY RECOVERY		580,940			
29	DIRECTLY CREDITED TO 44X		-4			
30						
31	TOTAL INDUSTRIAL	9,695,377	524,963,310	8,578	1,130,261	0.0541
32						
33						
34	PUBLIC STREET & HIGHWAY					
35						
36	L-1 ENERGY ONLY	21,491	1,371,659	296	72,605	0.0638
37	L-2 CUSTOMER OWNED	876	67,925	28	31,286	0.0775
38	L-3 COMPANY OWNED	134,148	20,159,896	1,436	93,418	0.1503
39	SPECIAL CONTRACT GR	25,195	1,356,220	1	25,195,000	0.0538
40	UNBILLED REVENUE					
41	TOTAL Billed	33,263,947	2,374,857,776	1,760,882	18,891	0.0714
42	Total Unbilled Rev.(See Instr. 6)	-224,629	-13,069,383	0	0	0.0582
43	TOTAL	33,039,318	2,361,788,393	1,760,882	18,763	0.0715

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RENEWABLE ENERGY					
2	PLANNED LOAD MGMNT					
3	SECURITIZATION SAVINGS RES					
4	ERIP		92,915			
5	SECURITY RECOVERY		14,565			
6	DIRECTLY CREDITED TO 44X		-1			
7						
8	TOTAL STREETLIGHTING	181,710	23,063,179	1,761	103,186	0.1269
9						
10						
11	INTERDEPARTMENTAL SALES					
12						
13	INTERDEPARTMENTAL	48,567	3,150,330			0.0649
14	UNBILLED REVENUE	-295	354			-0.0012
15	RENEWABLE ENERGY					
16	PLANNED LOAD MGMNT					
17	SECURITIZATION SAVINGS RES					
18	ERIP		23,961			
19	SECURITY RECOVERY		4,354			
20	DIRECTLY CREDITED TO 44X		1			
21						
22	TOTAL INTERDEPARTMENTAL	48,272	3,179,000			0.0659
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	33,263,947	2,374,857,776	1,760,882	18,891	0.0714
42	Total Unbilled Rev.(See Instr. 6)	-224,629	-13,069,383	0	0	0.0582
43	TOTAL	33,039,318	2,361,788,393	1,760,882	18,763	0.0715

Schedule Page: 304 Line No.: 1 Column: c

(A)	(B)	(C)
5. ESTIMATED REVENUE FROM FUEL ADJUSTMENT CLAUSES		
A-1		$41,390,674
A-3		154,462
A-4		1,058,492
A-5		918,953
B		11,047,061
C		21,837,678
B-1		1,745,040
D		30,537,139
F		5,286,727
GH		190,552
H		24,990
I		70,177
J		285,621
J-1		1,371,105
CG		134,358
R-1		36
R-2		3,339
R-3		975,292
UR		439,276
PS-1		278,945
PS-2		340,401
PS-3		1,667,893
L-1		94,021
L-2		3,869
L-3		591,203
L-4		61,813
SPECIAL CONTRACT - GR		110,997
SPECIAL CONTRACTS		659,459
INTERDEPARTMENTAL		214,603
TOTAL EST REVENUE FROM FUEL ADJUSTMENT CLAUSES PRIOR TO EFFECTS OF UNBILLED SALES		$121,494,176
PROVISION FOR RATE REFUNDS		(3,792,355)
ESTIMATED AMOUNT OF UNBILLED REVENUE ATTRIBUTABLE TO FUEL CLAUSE REVENUE		1,381,276
TOTAL ESTIMATED REVENUE FROM FUEL ADJUSTMENT CLAUSES		$119,083,097

Schedule Page: 304 Line No.: 42 Column: c

TOTAL UNBILLED REVENUE	(13,024,656)
RENEWABLE ENERGY	23,955
PLANNED LOAD MGMNT	(1,658,247)
SECURITIZATION SAVINGS RESERVE	(6,108,000)
ERIP	7,662,601
SECURITY RECOVERY	1,034,735
SPECIAL CONTRACT DISCOUNT	(999,763)
DIRECTLY CREDITED TO 44X	(8)
	(13,069,383)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	REQUIREMENTS					
2	Alpena	RQ	1		31	31
3	Edison Sault	RQ	1		20	20
4						
5	Unbilled	RQ				
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
					1
250,755	5,476,150	4,023,161		9,499,311	2
175,700	2,887,000	2,464,149		5,351,149	3
					4
-37		60,500		60,500	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
426,418	8,363,150	6,547,810	0	14,910,960	
2,515,010	1,309,574	93,253,555	6,283,474	100,846,603	
2,941,428	**9,672,724**	**99,801,365**	**6,283,474**	**115,757,563**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	INTERRUPTIBLE					
2	Alpena	OS	1		19	11
3	Edison Sault	OS	1		0	0
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
					1
34,345	439,616	1,018,582		1,458,198	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
426,418	8,363,150	6,547,810	0	14,910,960	
2,515,010	1,309,574	93,253,555	6,283,474	100,846,603	
2,941,428	**9,672,724**	**99,801,365**	**6,283,474**	**115,757,563**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	INTERSYSTEM SALES					
2	Campbell 3 (backup)					
3	Wolverine Power Supply Cooperative	OS	7,9,48			
4	Michigan Public Power Agency Backup	OS	7,47,71,72			
5	Michigan Municipals & Co Ops					
6	Holland Board of Public Works	OS	7,9			
7	Michigan South Central Power Agency	OS	7,9,55			
8	Third Parties					
9	Ontario Power Generation	OS	9			
10	The Detroit Edison Company	OS	9			
11	American Elelctric Power Service Corp	OS	3,9,23			
12	Northnern Indiana Public Service Comp	OS	7,9,45			
13	Ameren Energy	OS	9			
14	Entergy-Koch Trading	OS	9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
					1
					2
69,769	250,270	2,439,768		2,690,038	3
65,628	619,688	2,528,238		3,147,926	4
					5
95,014		4,010,015		4,010,015	6
6,654		280,484		280,484	7
					8
12,096		373,968		373,968	9
139,164		6,329,751		6,329,751	10
84,225		4,044,795		4,044,795	11
28,215		1,424,070		1,424,070	12
560		20,220		20,220	13
99,929		3,036,582		3,036,582	14
426,418	8,363,150	6,547,810	0	14,910,960	
2,515,010	1,309,574	93,253,555	6,283,474	100,846,603	
2,941,428	**9,672,724**	**99,801,365**	**6,283,474**	**115,757,563**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Exelon Generating	OS	8			
2	Coral Power	OS				
3	Carolina Power & Light	OS	9			
4	Cinergy Services	OS	8,9			
5	Constellation Power Source	OS	8			
6	Cargill Power Markets	OS	7,9			
7	Duke Energy Trading & Marketing	OS	9			
8	Dayton Power & Light	OS	9			
9	DTE Energy Trading	OS	9			
10	Engage Energy America	OS	9			
11	PP&L Energy Plus	OS				
12	First Energy Solutions	OS	2,8,22			
13	Louisville Gas & Electric Energy Corp.	OS	9			
14	Mirant Americas Energy Marketing	OS				
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
4,455		147,675		147,675	1
50		1,750		1,750	2
197		6,472		6,472	3
198,075		7,876,571		7,876,571	4
417,418		16,077,448		16,077,448	5
240,901		8,265,670		8,265,670	6
14,854		871,773		871,773	7
12,940		652,128		652,128	8
336,207		11,934,414		11,934,414	9
		2,400		2,400	10
		1,650		1,650	11
5,500		226,450		226,450	12
3,545		138,254		138,254	13
225,710		6,962,090		6,962,090	14
426,418	8,363,150	6,547,810	0	14,910,960	
2,515,010	1,309,574	93,253,555	6,283,474	100,846,603	
2,941,428	**9,672,724**	**99,801,365**	**6,283,474**	**115,757,563**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Transalta	OS	9			
2	Tenaska Power Services	OS	7			
3	Tenneessee Valley Authority	OS				
4	Wisconsin Electric Power	OS	8,9			
5	Other Sales	OS	9			
6	CMS Marketing Services & Trading	OS				
7	Split Rock Energy					
8	PJM					
9	Wolverine Power Supply					
10						
11	Intersystem Ancillary					
12	Ancillary Services - METCO					
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
82,409		3,079,438		3,079,438	1
35,736		1,158,302		1,158,302	2
525		27,500		27,500	3
6,935		290,030		290,030	4
837		291,681		291,681	5
74,684		2,643,446		2,643,446	6
74,896		2,495,741		2,495,741	7
1,577		62,671		62,671	8
141,960		4,533,528		4,533,528	9
					10
			6,283,474	6,283,474	11
					12
					13
					14
426,418	8,363,150	6,547,810	0	14,910,960	
2,515,010	1,309,574	93,253,555	6,283,474	100,846,603	
2,941,428	**9,672,724**	**99,801,365**	**6,283,474**	**115,757,563**	

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FOOTNOTE DATA

Schedule Page: 310.4 Line No.: 6 Column: a

An affiliated company has an ownership interest in this company

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	15,101,249	14,898,312
5	(501) Fuel *	305,563,127	305,819,276
6	(502) Steam Expenses	13,452,097	12,862,728
7	(503) Steam from Other Sources	0	0
8	(Less) (504) Steam Transferred-Cr.	0	0
9	(505) Electric Expenses	8,563,900	8,242,178
10	(506) Miscellaneous Steam Power Expenses	8,606,745	8,148,227
11	(507) Rents	0	0
12	(509) Allowances	3,810,149	0
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	355,097,267	349,970,721
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	5,961,842	6,070,522
16	(511) Maintenance of Structures	5,202,336	5,278,641
17	(512) Maintenance of Boiler Plant	30,013,572	27,320,672
18	(513) Maintenance of Electric Plant	14,198,452	9,435,132
19	(514) Maintenance of Miscellaneous Steam Plant	2,233,259	1,744,503
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	57,609,461	49,849,470
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	412,706,728	399,820,191
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	13,806,240	12,878,535
25	(518) Fuel	19,724,960	23,059,696
26	(519) Coolants and Water	4,676,138	5,208,968
27	(520) Steam Expenses	12,428,650	11,808,565
28	(521) Steam from Other Sources	0	0
29	(Less) (522) Steam Transferred-Cr.	0	0
30	(523) Electric Expenses	5,599,915	5,874,007
31	(524) Miscellaneous Nuclear Power Expenses	37,157,559	26,920,926
32	(525) Rents	598,360	724,792
33	TOTAL Operation (Enter Total of lines 24 thru 32)	93,991,822	86,475,489
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	11,101,926	12,545,964
36	(529) Maintenance of Structures	855,567	982,310
37	(530) Maintenance of Reactor Plant Equipment	27,894,724	15,705,348
38	(531) Maintenance of Electric Plant	7,485,874	7,239,239
39	(532) Maintenance of Miscellaneous Nuclear Plant	3,480,625	4,195,146
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	50,818,716	40,668,007
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	144,810,538	127,143,496
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	721,428	726,506
45	(536) Water for Power	1,089,259	1,040,345
46	(537) Hydraulic Expenses	1,627,449	3,164,510
47	(538) Electric Expenses	1,491,287	1,464,785
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,019,714	894,658
49	(540) Rents	84	4,200
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	5,949,221	7,295,004

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	317,899	321,776
54	(542) Maintenance of Structures	277,542	279,228
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,554,467	1,259,913
56	(544) Maintenance of Electric Plant	1,887,409	1,616,669
57	(545) Maintenance of Miscellaneous Hydraulic Plant	842,789	887,094
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,880,106	4,364,680
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	10,829,327	11,659,684
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	171,275	189,638
63	(547) Fuel	1,455,873	1,597,329
64	(548) Generation Expenses	174,785	34,029
65	(549) Miscellaneous Other Power Generation Expenses	55,262	60,203
66	(550) Rents	0	0
67	TOTAL Operation (Enter Total of lines 62 thru 66)	1,857,195	1,881,199
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	153,125	215,540
70	(552) Maintenance of Structures	18,717	2,821
71	(553) Maintenance of Generating and Electric Plant	1,196,432	910,819
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	0	0
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,368,274	1,129,180
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	3,225,469	3,010,379
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	807,712,378	748,685,229
77	(556) System Control and Load Dispatching	8,876,746	8,295,169
78	(557) Other Expenses	0	0
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	816,589,124	756,980,398
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,388,161,186	1,298,614,148
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	0	0
84	(561) Load Dispatching	0	0
85	(562) Station Expenses	0	273
86	(563) Overhead Lines Expenses	0	0
87	(564) Underground Lines Expenses	0	0
88	(565) Transmission of Electricity by Others	85,821,622	87,213,895
89	(566) Miscellaneous Transmission Expenses	0	0
90	(567) Rents	0	0
91	TOTAL Operation (Enter Total of lines 83 thru 90)	85,821,622	87,214,168
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	0	0
94	(569) Maintenance of Structures	0	0
95	(570) Maintenance of Station Equipment	0	0
96	(571) Maintenance of Overhead Lines	0	0
97	(572) Maintenance of Underground Lines	0	0
98	(573) Maintenance of Miscellaneous Transmission Plant	0	0
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	0	0
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	85,821,622	87,214,168

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	18,040,955	18,954,950
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	0	0
106	(582) Station Expenses	3,420,873	3,841,494
107	(583) Overhead Line Expenses	8,594,000	8,031,901
108	(584) Underground Line Expenses	3,290,539	2,085,651
109	(585) Street Lighting and Signal System Expenses	938,426	0
110	(586) Meter Expenses	4,523,855	3,584,370
111	(587) Customer Installations Expenses	9,037,921	9,140,570
112	(588) Miscellaneous Expenses	15,674,808	16,272,372
113	(589) Rents	2,291,108	2,295,879
114	TOTAL Operation (Enter Total of lines 103 thru 113)	65,812,485	64,207,187
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	5,287,316	5,349,009
117	(591) Maintenance of Structures	811,428	286,874
118	(592) Maintenance of Station Equipment	5,331,170	5,848,478
119	(593) Maintenance of Overhead Lines	32,775,310	37,637,086
120	(594) Maintenance of Underground Lines	2,468,031	2,138,369
121	(595) Maintenance of Line Transformers	516,955	466,023
122	(596) Maintenance of Street Lighting and Signal Systems	572,748	1,384,191
123	(597) Maintenance of Meters	694,008	972,107
124	(598) Maintenance of Miscellaneous Distribution Plant	4,125	13,828
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	48,461,091	54,095,965
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	114,273,576	118,303,152
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	8,559,012	8,482,817
130	(902) Meter Reading Expenses	9,172,039	8,329,100
131	(903) Customer Records and Collection Expenses	23,563,509	23,711,830
132	(904) Uncollectible Accounts	7,899,306	9,038,963
133	(905) Miscellaneous Customer Accounts Expenses	577,191	647,922
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	49,771,057	50,210,632
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	150,159	78,934
138	(908) Customer Assistance Expenses	4,762,189	5,168,046
139	(909) Informational and Instructional Expenses	375,065	538,853
140	(910) Miscellaneous Customer Service and Informational Expenses	0	0
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	5,287,413	5,785,833
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision	1,121,366	1,253,904
145	(912) Demonstrating and Selling Expenses	128,142	161,054
146	(913) Advertising Expenses	0	0
147	(916) Miscellaneous Sales Expenses	0	0

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	1,249,508	1,414,958
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	27,328,868	19,836,860
152	(921) Office Supplies and Expenses	6,559,374	5,072,656
153	(Less) (922) Administrative Expenses Transferred-Credit	2,558,400	2,653,200
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	5,367,924	7,411,542
156	(924) Property Insurance	8,335,510	7,214,668
157	(925) Injuries and Damages	14,650,104	14,699,480
158	(926) Employee Pensions and Benefits	58,477,000	107,395,320
159	(927) Franchise Requirements	0	0
160	(928) Regulatory Commission Expenses	(414,822)	403,699
161	(929) (Less) Duplicate Charges-Cr.	0	0
162	(930.1) General Advertising Expenses	1,088,322	1,188,257
163	(930.2) Miscellaneous General Expenses	3,241,508	3,153,898
164	(931) Rents	757,476	1,365,903
165	TOTAL Operation (Enter Total of lines 151 thru 164)	122,832,864	165,089,083
166	Maintenance		
167	(935) Maintenance of General Plant	2,356,668	1,799,745
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	125,189,532	166,888,828
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	1,769,753,894	1,728,431,719

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31 or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, includes such employees on line 3, and show the number of such special construction employees in a footnote.

1	Payroll Period Ended (Date)		12/31/2004
2	Total Regular Full-Time Employees		5111
3	Total Part-Time and Temporary Employees (Full Time Equivalents)		28
4	Total Employees		5139

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	BLACK RIVER	LU				
2	CITY OF BEAVERTON	LU				
3	COMMONWEALTH HUBBARDSTON	LU				
4	COMMONWEALTH IRVING	LU				
5	COMMONWEALTH LABARGE	LU				
6	COMMONWEALTH MIDDLEVILLE	LU				
7	GRAND VALLEY STATE UNIVERSITY	LU				
8	GRANGER - SEYMOUR	LU				
9	GREAT LAKE TISSUE	LU				
10	GRENFELL HYDRO	LU				
11	MICHIANA HYDRO	LU				
12	MICHIGAN STATE UNIVERSITY	LU				
13	SD WARREN	LU				
14	STS CASCADES	LU				
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,037			64,932	59,861	-3,798	120,995	1
2,503			77,291	54,361	-2,502	129,150	2
234			8,864	4,563	-233	13,194	3
1,310			46,366	32,064	-1,435	76,995	4
2,661			100,729	52,047	-2,660	150,116	5
928			36,051	23,839	-1,029	58,861	6
116				2,779		2,779	7
3,893			177,428	64,575	-3,895	238,108	8
24				551	-24	527	9
1,562			57,601	30,893	-1,563	86,931	10
221			11,108	4,332	-222	15,218	11
785				15,693	-723	14,970	12
2,282				60,852		60,852	13
7,116			276,974	154,559	-7,115	424,418	14
14,451,924			516,278,332	292,281,557	-847,511	807,712,378	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	STS FALLASBURG	LU				
2	STS MORROW	LU				
3	THORNAPPLE	LU				
4	WESTERN MICHIGAN UNIVERSITY	LU				
5	WHITE'S BRIDGE	LU				
6	MIDLAND COGENERATION VENTURE	LU				
7	PETER JOHN MOEHN	LU				
8	ADA COGENERATION	LU				
9	ADRIAN ENERGY	LU				
10	BIO ENERGY POWER	LU				
11	CADILLAC RENEWABLE	LU				
12	FILER CITY	LU				
13	GAS RECOVERY SYSTEMS	LU				
14	GENESEE POWER STATION	LU				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,437			125,717	96,388	-4,437	217,668	1
4,098			161,842	97,208	-4,452	254,598	2
5,785			177,524	125,553	-5,715	297,362	3
9,149				163,525	-9,768	153,757	4
2,684			92,551	52,790	-2,684	142,657	5
10,144,410			343,618,959	200,793,565	-24,000	544,388,524	6
2				51	-1	50	7
174,598			11,599,822	2,755,476	-20,000	14,335,298	8
18,930			755,555	380,947	-18,865	1,117,637	9
10,228			489,578	165,807	-10,249	645,136	10
224,082			12,834,368	3,226,363	-24,000	16,036,731	11
501,610			23,227,221	9,864,259	-24,000	33,067,480	12
20,018			937,008	322,326	-19,808	1,239,526	13
234,312			12,449,464	3,735,964	-20,770	16,164,658	14
14,451,924			516,278,332	292,281,557	-847,511	807,712,378	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	GRANGER - GRAND BLANC	LU				
2	GRANGER RENEWAL RES LANDFILL (1A)	LU				
3	GRANGER RENEWAL RES LANDFILL (2A)	LU				
4	GRANGER - OTTAWA	LU				
5	GRAYLING	LU				
6	HILLMAN LIMITED	LU				
7	KENT COMPANY	LU				
8	MICHIGAN POWER LIMITED	LU				
9	NORTH AMERICAN RESOURCES	LU				
10	VIKING - LINCOLN	LU				
11	VIKING - MCBAIN	LU				
12	WOLVERINE POWER COMPANY	OS				
13	BAY WINDPOWER	LU				
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
27,193			1,543,530	415,097	-27,072	1,931,555	1
19,608			1,194,891	330,718	-20,162	1,505,447	2
23,096			1,441,327	381,811	-22,741	1,800,397	3
39,807			1,801,640	662,601	-32,544	2,431,697	4
280,657			13,631,678	4,473,789	-32,545	18,072,922	5
142,735			5,026,332	2,818,591	-142,870	7,702,053	6
92,071			4,493,696	1,818,975	-24,000	6,288,671	7
1,031,835			54,622,213	20,489,960	-24,000	75,088,173	8
26,099			1,131,623	434,985	-26,022	1,540,586	9
145,213			5,724,041	2,875,883	-145,278	8,454,646	10
134,390			5,290,302	2,660,152	-134,424	7,816,030	11
34,014			294,103	707,464		1,001,567	12
1,906				101,405	-1,905	99,500	13
							14
14,451,924			516,278,332	292,281,557	-847,511	807,712,378	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1						
2	PP OPTION 3rd PARTIES					
3						
4						
5						
6	AMERICAN ELECTRIC POWER	OS				
7	AMEREN ENERGY	OS				
8	ENTERGY-KOCH TRADING	OS				
9	CARGILL POWER MARKETS	OS				
10	PROGRESS ENERGY CAROLINAS	OS				
11	CINERGY SERVICES	OS				
12	CONSTELLATION POWER SOURCE	OS				
13	CMS MARKETING SERVICES & TRADING	OS				
14	DAYTON PWR & LGHT	OS				
	Total					

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
			12,756,003			12,756,003	2
							3
							4
							5
176,253				5,595,794		5,595,794	6
61,998				1,614,299		1,614,299	7
25,120				351,721		351,721	8
21,290				876,594		876,594	9
162				11,566		11,566	10
145,514				5,653,523		5,653,523	11
3,391				208,655		208,655	12
							13
12,288				382,397		382,397	14
14,451,924			516,278,332	292,281,557	-847,511	807,712,378	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	DTE ENERGY TRADING	OS				
2	DUKE POWER	OS				
3	DUKE ENERGY TRADING & MARKETING	OS				
4	DYNEGY POWER MARKETING	OS				
5	ENGAGE ENERGY AMERICA	OS				
6	EXCELON GENERATING	OS				
7	FIRST ENERGY SOLUTIONS	OS				
8	MICHIGAN PUBLIC POWER AGENCY	OS				
9	NORTHERN INDIANA PUBLIC SERVICE	OS				
10	ONTARIO HYDRO	OS				
11	PUR POWER - OTHER PURCH	OS				
12	SOUTHERN COMPANY SERVICES	OS				
13	SPLIT ROCK ENERGY	OS				
14	TENASKA POWER SERVICES	OS				
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
129,337				5,336,732		5,336,732	1
3,150				187,800		187,800	2
2,562				115,286		115,286	3
2,320				99,422		99,422	4
13,300				910,320		910,320	5
31,329				746,220		746,220	6
23,592				665,854		665,854	7
							8
10,887				337,603		337,603	9
							10
352,925				5,853,759		5,853,759	11
							12
687				29,197		29,197	13
							14
14,451,924			516,278,332	292,281,557	-847,511	807,712,378	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	TRANSALTA	OS				
2	THE DETROIT EDISON COMPANY	OS				
3	WILLIAMS ENERGY MARKETING &	OS				
4	LG&E ENERGY CORP	OS				
5	MIRANT AMERICAS ENERGY MKT	OS				
6	PJM	OS				
7	WOLVERINE SUPPLY CORPORATION	OS				
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2004/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
36				14,328		14,328	1
29,609				1,346,983		1,346,983	2
7,750				535,640		535,640	3
7,725				329,800		329,800	4
10,341				545,048		545,048	5
325				8,059		8,059	6
394				12,335		12,335	7
							8
							9
							10
							11
							12
							13
							14
14,451,924			516,278,332	292,281,557	-847,511	807,712,378	

FOOTNOTE DATA

Schedule Page: 326.1 Line No.: 6 Column: a

An affiliated company has an ownership interest in this company

Schedule Page: 326.1 Line No.: 12 Column: a

An affiliated company has an ownership interest in this company

Schedule Page: 326.1 Line No.: 14 Column: a

An affiliated company has an ownership interest in this company

Schedule Page: 326.2 Line No.: 5 Column: a

An affiliated company has an ownership interest in this company

Schedule Page: 326.3 Line No.: 2 Column: a

Capacity options were purchased for the year from several providers.

Schedule Page: 326.3 Line No.: 13 Column: a

An affiliated company has an ownership interest in this company

SALES TO RAILROADS AND RAILWAYS AND INTERDEPARTMENTAL SALES (Accounts 446, 448)

1. Report particulars concerning sales included in Accounts 446 and 448.
2. For Sales to Railroads and Railways, Account 446, give name of railroad or railway in addition to other required information. If contract covers several points of delivery and small amounts of electricity are delivered at each point, such sales may be grouped.
3. For Interdepartmental Sales, Account 448, give name of other department and basis of charge to other department in addition to other required information.
4. Designate associated companies.
5. Provide subheading and total for each account.

Line No.	Item (a)	Point of Delivery (b)	Kilowatt-hours (c)	Revenue (d)	Revenue per kWh (in cents) (e)
1	ACCOUNT 446				
2	None				
3					
4	ACCOUNT 448				
5	Interdepartmental Sales				
6	Gas Department,				
7	Combination and Other	Various	48,272,163	$3,179,000	6.6
8					
9					
10					
11					

RENT FROM ELECTRIC PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 454, 455)

1. Report particulars concerning rents received included in Accounts 454 and 455.
2. Minor rents may be grouped by classes.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation and taxes, give particulars and the basis of apportionment of such charges to Accounts 454 or 455.
4. Designate if lessee is an associated company.
5. Provide a subheading and total for each account.

Line No.	Item (a)	Description of Property (b)	Amount of Revenue for Year (c)
15	ACCOUNT 454		
16	SBC Telephone Company	Poles	3,196,646
17	Verizon Telephone Company	Poles	1,883,473
18	Century Telephone Company	Poles	71,073
19	Cable Television Companies and Internet Connection	Poles	3,333,676
20	Other Miscellaneous Pole Rentals:		
21	5 Various Telephone Companies Operating		
22	in the Company Service Area	Poles	171,840
23	Miscellaneous Rentals, Including Utility		
24	Property Leased to Various Parties		
25	Throughout the Company's Service Area	Various	2,775,089
26	Lease Rev- Michigan Electric Transmission Company	Transmission Rights of Way	10,041,000
27			
28	Total Account 454		21,472,797
29			
30	ACCOUNT 455 - None		
31			
32			

SALES OF WATER AND WATER POWER (Account 453)

1. Report below the information called for concerning revenues derived during the year from sales to others of water or water power.
2. In column (c) show the name of the power development of the respondent supplying the water or water power sold.
3. Designate associated companies.

Line No.	Name of Purchaser (a)	Purpose for Which Water Was Used (b)	Power Plant Development Supplying Water or Water Power (c)	Amount of Revenue for Year (d)
1	None			
2				
3				
4				
5				
6				
7	TOTAL			

MISCELLANEOUS SERVICE REVENUES AND OTHER ELECTRIC REVENUES (Accounts 451, 456)

1. Report particulars concerning miscellaneous service revenues and other electric revenues derived from electric utility operations during year. Report separately in this schedule the total revenues from operations of fish and wildlife and recreation facilities, regardless of whether such facilities are operated by company or by contract concessionaires. Provide a subheading and total for each account. For Account 456, list first revenues realized through Research and Development ventures, see Account 456.
2. Designate associated companies.
3. Minor items may be grouped by classes.

Line No.	Name of Company and Description of Service (a)	Amount of Revenue for Year (b)
11	MISCELLANEOUS SERVICE REVENUE - ACCOUNT 451	
12	Fees for reconnecting service previously disconnected and charges for installing and	
13	removing temporary services	$2,378,060
14		
15	OTHER ELECTRIC REVENUES - ACCOUNT 456	
16	Retail Open Access	24,519,006
17	Sub Station Maintenance Rev- Non Consumers Equipment	222,592
18	Rate of Return Billed to Others	3,367,381
19	Network Wholesale Revenue	1,000,534
20	Sales and Use Tax Discount	320,191
21	Other Electric Revenue	669,386
22		
23		
24		
25		
26		
27		
28		$30,099,090
29		
30		
31		
32	Total Account 456	
33		
34	TOTAL	$32,477,150

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	METC LLC			75,214,016				
2	MISO			7,703,753				
3	AEP			4,485,030				
4	PJM			2,350,131				
5	Remarketed Transm.			-1,118,965				
6	Recoverable Transm.			-2,812,343				
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL			85,821,622				

BLANK PAGE

Schedule Page: 332 Line No.: 5 Column: d

Remarketed transmission capacity sold to various counterparties.

Schedule Page: 332 Line No.: 6 Column: d

Represents the portion of 2004 transmission expense deferred to account 182 as a regulatory asset under the provisions of Public Act 141.

LEASE RENTALS CHARGED

1. For purposes of this schedule a "lease" is defined as a contract or other agreement by which one party (lessor) conveys an intangible right or land or other tangible property and equipment to another (lessee) for a specified period of one year or more for rent.
2. Report below, for leases with annual charges of $25,000 or more, but less than $250,000 the data called for in column a, b (description only), f, g and j.
3. For leases having annual charges of $250,000 or more, report the data called for in all the columns below.
4. The annual charges referred to in Instruction 2 and 3 include the basic lease payment and other payments to or on behalf of the lessor such as taxes, depreciation, assumed interest or dividends on the lessor's securities, cost of replacements** and other expenditures with respect to leased property. The expenses paid by lessee are to be itemized in column (e) below.
5. Leases of construction equipment in connecting with construction work in progress are not required to be reported herein. Continuous, master or open-end leases for EDP or office equipment, automobile fleets and other equipment that is short-lived and replaced under terms of the lease or for pole rentals shall report only the data called for in columns a, b (description only), f, g and j, unless the lessee has the option to purchase the property.
6. In column (a) report the name of the lessor. List lessors which are associated companies* (describing association) first, followed by non-associated lessors.
7. In column (b) for each leasing arrangement, report in order, classified by generating station, transmission line, distribution system, large substation, or other operating unit or system, followed by any other leasing arrangements not covered under the preceding classifications:

A. LEASE RENTALS CHARGED TO ELECTRIC OPERATING EXPENSES

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Renewal (R) (c)
Bankers Leasing Corp	Vehicles, Office Equipment, EDP Equipment, Material Handling Equipment, Tools & Garage Equipment, Lab & Instrument Equipment, Construction & Maintenance Equipment and Communications Equipment (Note 1)	
Merrill Lynch	Office Furniture (Note 4)	2013(P)
Verizon	Joint Pole Rentals	
SBC, Michigan	Joint Pole Rentals	
1016 Sixteenth Street NW Venture	Office Space - Washington DC	
Consumsan Company, LLC C/O Kin Properties	Lansing Service Center	
Consumsan Company, LLC C/O Kin Properties	Saginaw Service Center	
Walter Neller Enterprises	Office Space - Mail Remittance	

** See Electric Plant Instruction 6 & Operating Expense Instruction 3 of the Uniform System of Accounts.

LEASE RENTALS CHARGED (Continued)

Description of the property, whether lease is a sale and leaseback, whether lessee has option to purchase and conditions of purchase, whether lease is cancellable by either party and the cancellation conditions, the tax treatment used, the accounting treatment of the lease payments (levelized charges to expense or other treatment), the basis of any charges apportined between the lessor and lessee, and the responsibility of the respodent for operation and maintenance expenses and replacement of property. The above information is to be reported with initiation of the lease and thereafter when changed or every five years, which ever occurs first.

8. Report in column (d), as of the date of the current lease term, the original cost of the property leased, estimated if not known, or the fair market of the property if greater than original cost and indicate as shown. If leased property is part of a large unit, such as part of a building, indicate without associating any cost or value with it.

9. Report in column (k) below the estimated remaining annual charges under the current term of the lease. Do not apply a present value to the estimate. Assume that cancellable leases will not be cancelled when estimating the remaining charges.

A. LEASE RENTALS CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Original Cost (O) or Fair Market Value (F) of Property (d)	Expense To Be Paid by Lessee Itemize (e)	Amount of Rent - Current Term				Account Charged (j)	Remaining Annual Charges Under Lease (Estimate if Not Known) (k)
		Current Year		Accumulated to Date			
		Lessor (f)	Other (g)	Lessor (h)	Other (i)		
		8,729,288				(Note 3)	
4,091,186(O)	O&M, T	815,075		1,344,740		(Note 3)	4,331,876
		585,943				589	
		1,573,406				589	
		79,091				921	
		32,800				(Note 3)	
		45,574				(Note 3)	
		43,389				(Note 3)	

A. LEASE RENTALS CHARGED TO ELECTRIC OPERATING EXPENSES		
Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Renewal (R) (c)
Phyleo Realty Co	Storage Area - Jackson	
Douglas & Lois Nagel	Storage - Kentwood	
Great Lakes Motor Coach	Office Space - Belmont	
Derek R. Lone	Storage - Benzonia	
C.E. Financial Services, L.L.C.	Ludington Service Center	
Jack Stover	South Monroe Service Center	
GE Capital Fleet Services	Vehicles (Note 1)	
B. OTHER LEASE RENTALS CHARGED (Such as to Deferred Debits, etc.)		
General American Transportation Corp	Railroad Tank Cars (Note 5)	2005(P)
Coal Supply	Railroad Cars (Note 5)	2008(P)
Coal Supply II	Railroad Cars (Note 5)	2012(P)
Fuel Supply Trust (FSTX)	Railroad Cars (Note 5)	2015(P)
General American Transportation Corp	Railroad Tank Cars (Note 5)	2005(P)
Provident Commercial Group (DJJ)	Railroad Cars (Note 5)	2004(P)
Babcock & Brown Rail Leasing	Railroad Cars (Note 5)	2007(P)
Babcock & Brown Rail Leasing	Railroad Cars (Note 5)	2009(P)
Mitsui Rail Capital	Railroad Cars (Note 5)	2009(P)
GATX Rail Corporation	Railroad Cars (Note 5)	2006(P)

A. LEASE RENTALS CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Original Cost (O) or Fair Market Value (F) of Property (d)	Expense To Be Paid by Lessee Itemize (e)	Amount of Rent - Current Term				Account Charged (j)	Remaining Annual Charges Under Lease (Estimate if Not Known) (k)
		Current Year		Accumulated to Date			
		Lessor (f)	Other (g)	Lessor (h)	Other (i)		
	(Note 2)	179,584				(Note 3)	
		141,006				(Note 3)	
		61,337				(Note 3)	
		52,742				(Note 3)	
		134,496				(Note 3)	
		77,474				(Note 3)	
		212,903				(Note 3)	

B. OTHER LEASE RENTALS CHARGED (Such as to Deferred Debits, etc.)

1,442,490 (O)	O&M T	351,000		2,356,512		151	265,200
9,532,341 (O)	O&M T I	1,137,154		18,404,591		151	3,912,901
9,455,321 (O)	O&M T I	1,332,640		13,403,399		151	10,857,862
38,004,357 (O)	O&M T I	3,997,599		32,441,256		151	43,973,594
1,442,490 (O)	O&M T I	307,050		1,775,550		151	160,200
16,551,612 (O)	O&M T I	801,000		7,896,080		151	0
13,593,159 (O)	O&M T I	1,245,456		1,245,456		151	2,629,292
22,814,286 (O)	O&M T I	1,461,240		1,461,240		151	9,613,742
16,121,700 (O)	O&M T I	694,350		694,350		151	6,326,300
10,799,319 (O)	O&M T I	754,299		754,299		151	1,874,600

LEASE RENTALS CHARGED (Footnotes)

Notes:

(1) This master lease agreement involves numerous individual leases with various termination dates.

(2) T=Taxes, I=Insurance Costs, O&M=Operating and Maintenance Costs

(3) Amounts are charged to clearing accounts and cleared to Electric Operating Expense and Construction accounts monthly.

(4) The lease is on a sale leaseback contract. The lease term is for ten years. At the end of the lease, the Company has the option to purchase the furniture for its fair market value, return the equipment to the lessor and pay costs associated with the removal of the furniture, or renew the lease at the then current market prices. Also, the Company has the right to purchase the furniture at the end of five years or return it with a penalty of 21.5 percent of the furniture cost.

(5) Lease payments are charged to fuel inventory accounts and are expensed as used. Payments are treated the same for accounting and tax purposes.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	638,434
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6		
7	COMPANY COMMUNICATION SERVICES	
8	Learning Center LTD	22,765
9	Miscellaneous under $5000 (41 items)	13,797
10		
11	EMPLOYEE'S RELOCATION EXPENSE	
12	Cendant Mobility Service	352,829
13	Company Reimbursed Employee Expenses	292,224
14		
15	EXEMPT VACATION LIABILITY	
16	To Accrue Vacation Earned	660,482
17		
18	BOARD OF DIRECTORS FEES	559,368
19		
20	OTHER	
21	Various Banks-Service Charges	648,261
22	Company Labor and Expenses-Commercial Services	207,153
23	Billing Credits	-177,950
24	Miscellaneous expenses under 5000 (48 items)	24,145
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	3,241,508

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)
(EXCEPT AMORTIZATION OF ACQUISITION ADJUSTMENTS)

1. Report in Section A for the year the amounts for: (a) Depreciation Expense (Account 403); (b) Amortization of Limited-Term Electric Plant (Account 404); and (c) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Account 404, 405). State the basis used to compute the charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant account included in any subaccount used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a composite total. Indicate at the bottom of Section C the manner in which column (b) balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant.
If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of Section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Acct. 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant	-	590,449	765,545	1,355,994
2	Steam Production Plant	54,741,700	-	-	54,741,700
3	Nuclear Production Plant-Depreciation	5,210,200	-	-	5,210,200
	Nuclear Production Plant-Decommissioning	5,907,914	-	-	5,907,914
4	Hydraulic Production Plant-Conventional	1,650,300	-	-	1,650,300
5	Hydraulic Production Plant-Pumped Storage	5,568,700	-	-	5,568,700
6	Other Production Plant	345,600	-	-	345,600
7	Transmission Plant	0	-	-	0
8	Distribution Plant	89,340,800	-	-	89,340,800
9	General Plant	6,614,704	-	-	6,614,704
10	Common Plant-Electric	13,479,666	1,646,825	5,277,720	20,404,211
11	TOTAL	$182,859,584	$2,237,274	$6,043,265	$191,140,123

B. Basis for Amortization Charges

1 Amortization of Limited Term Plant is based on the life or the original building leases.
2 No change in the rates for accounts 404 and 405.
3 Amortization of Intangible Plant is based on the estimated life of the intangible plant.
4 Total Depreciation and Amortization Expense per Page 115, lines 6 and 7 191,689,153
Total Depreciation and Amortization Expense per Line 11, above 191,140,123
Electric ARO accretion/transition expense recorded in 411.0xx accounts 549,030
5 Common Plant Depreciation and Amortization Expenses:

	Account 403 (b)	Account 404 (c)	Account 405 (d)	Total (e)
A. Allocation of Common Depreciation & Amortization Expenses	13,479,666	1,646,825	5,277,720	20,404,211
B. Allocation of Gas Depreciation Expense	-	-	-	-
Total	13,479,666	1,646,825	5,277,720	20,404,211

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2004/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam						
13	310.2	836	55.00		1.58		
14	311.0	195,008	43.00	-5.70	2.54		
15	312.0	837,320	38.00	-7.00	3.04		
16	314.0	224,260	43.00	-6.20	2.40		
17	315.0	79,304	40.00	-6.10	2.69		
18	316.0 & 316.1	16,208	26.00	-8.30	4.74		
19							
20	Total	1,352,936					
21							
22	Campbell #3						
23	310.2	19	39.00		2.37		
24	311.0	196,631	39.00	-5.40	2.60		
25	312.0	313,927	37.00	-5.70	2.88		
26	314.0	60,543	38.00	-5.50	2.72		
27	315.0	44,110	39.00	-5.40	2.61		
28	316.0 & 316.1	5,176	33.00	-6.60	3.22		
29							
30	Total	620,406					
31							
32	Hydro						
33	330.3	41	105.00		2.47		
34	331.0 & 331.3	5,094	71.00		2.15		
35	332.0 & 332.1	47,938	76.00	-30.00	2.70		
36	333.0	5,344	85.00		2.16		
37	334.0	5,447	68.00		2.40		
38	335.0	1,925	45.00		2.64		
39	336.0	64	54.00		2.18		
40							
41	Total	65,853					
42	Ludington Pumped Storg						
43	331.0	16,901	55.00	-47.00	3.23		
44	332.0	97,933	55.00	-47.00	3.27		
45	333.0	41,574	55.00	-47.00	3.91		
46	334.0	2,888	55.00	-47.00	3.25		
47	335.0	1,863	55.00	-47.00	3.57		
48	336.0	1,536	55.00	-47.00	3.22		
49							
50	Total	162,695					

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2004/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Other						
13	341.0	759	32.00	-5.00	3.76		
14	342.0	401	35.00	-5.00	2.75		
15	344.0	41,665	36.00	-5.00	1.79		
16	345.0	2,474	28.00	-5.00	5.32		
17	346.0	528	18.00	5.00	9.42		
18							
19	Total	45,827					
20							
21	Distribution Prod.						
22	361.2	1,168	60.00	-15.00	2.01	R4	
23	362.2	23,264	50.00	-12.00	2.33	R2	
24							
25	Total	24,432					
26							
27	Distribution - HV						
28	360.4	37,464	75.00		1.38	R3	
29	361.1	12,677	60.00	-15.00	2.01	R4	
30	362.1	194,086	50.00	-12.00	2.33	R2	
31	364.1	3,169	75.00	-90.00	2.62	R3	
32	364.2	160	75.00		1.38	R3	
33	364.3	99,740	60.00	-45.00	2.50	R2.5	
34	364.4	11,300	70.00		1.51	R5	
35	365.2	82,128	60.00	-40.00	2.44	R3	
36	366.1	851	55.00	-20.00	2.29	S3	
37	367.1	3,497	40.00	-10.00	2.81	R2	
38	367.2	5	50.00	1.00	2.10	R2	
39							
40	Total	445,077					
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13	Distribution						
14	360.2	15,935	60.00		1.50	R2	
15	361.0	28,594	50.00	-15.00	2.17	S0.5	
16	362.0	379,940	38.00	-2.00	2.55	S-.5	
17	364.0	634,896	50.00	-132.00	4.39	R2	
18	365.0	619,251	55.00	-30.00	2.26	R1.5	
19	366.0	57,968	50.00	-30.00	2.46	S0.5	
20	367.0	363,918	45.00	-25.00	2.64	L2	
21	368.0	582,603	40.00	-25.00	2.92	S2	
22	369.1	152,315	45.00	-87.00	3.95	R1	
23	369.2	341,270	40.00	-25.00	3.01	R3	
24	370.0	150,927	29.00	-19.00	3.85	R1	
25	371.0	6,714	12.00	-6.00	8.41	L1	
26	373.0	81,789	30.00	-90.00	6.01	R0.5	
27							
28	Total	3,416,120					
29							
30	General						
31	389.2	190	50.00		11.76	S4	
32	390.0 & 390.1	38,470	40.00	-15.00	5.20	R2	
33	391.0 & 391.1	1,611	27.00	10.00	5.93	S-0.5	
34	391.2 & 391.3	12,071	7.00		24.60	R4	
35	393.0 & 393.1	85	35.00	5.00	8.37	S1.5	
36	394.0 & 394.1	5,306	26.00	10.00	5.67	L2	
37	395.0 & 395.1	4,688	25.00		5.55	S2	
38	396.0	1,758	12.00	20.00	17.50	L1	
39	397.0 & 397.1	35,617	20.00	-10.00	9.21	L2	
40	398.0 & 398.1	1,365	24.00		5.37	L2	
41							
42	Total	101,161					
43							
44							
45							
46							
47							
48							
49							
50							

Schedule Page: 336 Line No.: 3 Column: b

RESPONSE TO INSTRUCTION 4:

Nuclear Decommissioning (external trust funds) per MPSC Order No. U-11662 (effective January 1, 1999 and revised per the March 31, 2004 report on the adequacy of decommissioning trusts to provide funds for decommissioning).

	Palisades	Big Rock
Estimated 2003 Cost (000s)	868,014	361,091
Inflation Rate	3.85%	2.80%
Equity Earnings Rate	9.80%	8.50%
Fixed Income Earnings Rate	5.13%	1.50%
Plant Retirement Date	2011	1997

Notes:

The estimated cost excludes incremental spent nuclear fuel storage costs.

Schedule Page: 336 Line No.: 13 Column: e

Non-Ludington depreciation rates in column (e) pursuant to MPSC Order No. U-10754 (effective December 5, 1996). Ludington depreciation rates pursuant to MPSC Order No. U-11724 (effective April 1, 2000).

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS
AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) *Miscellaneous Amortization* (Account 425)- Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization

(b) *Miscellaneous Income Deductions*- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4 Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) *Interest on Debt to Associated Companies* (Account 430)- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) *Other Interest Expense* (Account 431)- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	ACCOUNT 425 - MISCELLANEOUS AMORTIZATION - NONE	
2		
3	ACCOUNT 426 - MISCELLANEOUS INCOME DEDUCTIONS	
4	426.1 - Donations	
5	United Way Organizations	2,240
6	CE Foundation Contribution/Commitments	749,134
7	Educational Institutions	3,375
8	Various Chambers of Commerce	4,215
9	Youth Programs	12,000
10	Cultural	1,150
11	Other Donations	108,887
12		
13		
14	Total - 426.1	881,001
15		
16	426.3 - Penalties and Other Deductions	
17	ASP - Code of Conduct Fines	97,100
18	Utility Outage Credits	1,909
19	Total - 426.3	99,009
20	426.4 - Expenditures of Civic & Political Activities	
21	Governmental Affairs Activity	2,584,226
22		
23	Total 426.4	2,584,226
24		
25	426.5 - Other Deductions	
26	CMS Energy Costs	197,026
27	Promotional Practices	28,613
28	Loss on Supplemental Retirement Plan Assets	942,034
29	Accretion Expenses - MCV Contract	1,062,000
30	Accretion Expense - Electric Call Options	1,555,683
31	Discriminatory Practices Expense - AR-12	256,022
32	MCV PPA Contract Loss	28,961,175
33	Economic Development Activity	459,445
34	Other Deductions	180,031
35		
36		
37		
38		
39		
40	Total 426.5	33,642,029

	PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS (continued)	
1	Account 430 - INTEREST ON NOTES PAYABLE TO	
2	ASSOCIATED COMPANIES	
3	CMS Midland - Various Rates	201,433
4	Consumers Power Company Financing I	
5	Trust Preferred Securities - 8.36%	6,110,558
6	Consumers Energy Company Financing II -	
7	Trust Preferred Securities - 8.20%	10,144,331
8	Consumers Energy Company Financing III -	
9	Trust Preferred Securities - 9.25%	16,688,145
10	Consumers Energy Company Financing IV -	
11	Trust Preferred Securities - 9.0%	11,597,940
12	Consumers Funding LLC - Securitization Bonds	21,136,115
13	Notes Payable - CMS Energy - Various Rates	2,350,969
14		
15	Total 430.2	68,229,491
16		
17		
18	Account 431 - OTHER INTEREST EXPENSE	
19	Bank One Credit Agreement - Various Rates	1,346,646
20		
21	Customer's Security Deposits - Various Rates	1,821,300
22	Deferred Executive Incentive Compensation	
23	Various Rates	175,414
24	Electric Contingency - Various Rates	2,141,338
25	Gas Customer Choice	58,882
26	Special Retirement Supplement -	468,657
27	PSCR Over/Under Recovery Interest	887,408
28	Unrefunded Bal - Electric	62,845
29	Unrefunded Bal - Gas	206,307
30	Company Transportation - Electric 8.0%	(87,632)
31	Company Transportation - Gas 8.0%	(85,105)
32	GCR Over/Under Recovery Interest	3,377,932
33	Miscellaneous Interest Charges - Various Rates	100,496
34		
35		
36		
37	Total 431	10,474,488

EXPENDITURES FOR CERTAIN CIVIC, POLITICAL AND RELATED ACTIVITIES (Account 426.4)

1. Report below all expenditures incurred by the respondent during the year for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances); approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials which are accounted for as Other Income Deductions, Expenditures for Certain Civic, Political and Related Activities, Account 426.4.

2. Advertising expenditures in this Account shall be classified according to subheadings, as follows: (a) radio, television, and motion picture advertising; (b) newspaper, magazine, and pamphlet advertising; (c) letters or inserts in customer's bills; (d) inserts in reports to stockholders; (e) newspaper and magazine editorial services; and (f) other advertising.

3. Expenditures within the definition of paragraph (1), other than advertising shall be reported according to captions or descriptions clearly indicating the nature and purpose of the activity.

4. If respondent has not incurred any expenditures contemplated by the instructions of Account 426.4, so state.

5. Minor amounts may be grouped by classes if the number of items so grouped is shown.

NOTE: The classification of expenses as nonoperating and their inclusion in this amount is for accounting purposes. It does not preclude Commission consideration of proof to the contrary for ratemaking or other purposes. It does not preclude Commission consideration

Line No.	Item (a)	Amount (b)
1	Associations/Industry Dues	$267,840
2		
3	Lobbying	$162,372
4		
5	Governmental Affairs Activity	$2,154,014
6		
7		
8	Total Account 426.4	$2,584,226
9		
10		
11		
12		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	MICHIGAN PUBLIC SERVICE COMMISSION				
2	Legal Publishing		228,001	228,001	
3					
4	Minor Items		134,921	134,921	
5					
6					
7	MICHIGAN DEPARTMENT OF MANAGEMENT AND				
8	BUDGET				
9	Payment Intervenor Funding	404,862		404,862	
10					
11	REGULATORY COMMISSION EXPENSE BILLED TO		-1,583	-1,583	
12	OTHERS				
13					
14	Reversal of Prior period accrual of				
15	Regulatory Commission Expense		-900,000	-900,000	
16					
17					
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45					
46	TOTAL	404,862	-538,661	-133,799	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
Electric	928	161,419					1
Gas	928	66,582					2
Electric	928	118,863					3
Gas	928	16,058					4
							5
							6
							7
Electric	928	206,480					8
Gas	928	198,382					9
							10
Electric	928	-1,583					11
							12
							13
							14
Electric	928	-900,000					15
							16
							17
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							45
		-133,799					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	49,726,590		
4	Transmission			
5	Distribution	28,056,174		
6	Customer Accounts	26,870,994		
7	Customer Service and Informational	4,042,014		
8	Sales	1,053,600		
9	Administrative and General	24,655,129		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	134,404,501		
11	Maintenance			
12	Production	20,232,034		
13	Transmission			
14	Distribution	16,747,695		
15	Administrative and General	170,051		
16	TOTAL Maint. (Total of lines 12 thru 15)	37,149,780		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	69,958,624		
19	Transmission (Enter Total of lines 4 and 13)			
20	Distribution (Enter Total of lines 5 and 14)	44,803,869		
21	Customer Accounts (Transcribe from line 6)	26,870,994		
22	Customer Service and Informational (Transcribe from line 7)	4,042,014		
23	Sales (Transcribe from line 8)	1,053,600		
24	Administrative and General (Enter Total of lines 9 and 15)	24,825,180		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	171,554,281	59,915,830	231,470,111
26	Gas			
27	Operation			
28	Production-Manufactured Gas			
29	Production-Nat. Gas (Including Expl. and Dev.)			
30	Other Gas Supply			
31	Storage, LNG Terminaling and Processing	2,642,211		
32	Transmission	5,760,944		
33	Distribution	33,735,623		
34	Customer Accounts	23,908,109		
35	Customer Service and Informational	666,403		
36	Sales	174,781		
37	Administrative and General	18,797,680		
38	TOTAL Operation (Enter Total of lines 28 thru 37)	85,685,751		
39	Maintenance			
40	Production-Manufactured Gas			
41	Production-Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing	1,533,161		
44	Transmission	998,809		
45	Distribution	14,113,033		
46	Administrative and General	73		
47	TOTAL Maint. (Enter Total of lines 40 thru 46)	16,645,076		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Total Operation and Maintenance			
49	Production-Manufactured Gas (Enter Total of lines 28 and 40)			
50	Production-Natural Gas (Including Expl. and Dev.) (Total lines 29,			
51	Other Gas Supply (Enter Total of lines 30 and 42)			
52	Storage, LNG Terminaling and Processing (Total of lines 31 thru	4,175,372		
53	Transmission (Lines 32 and 44)	6,759,753		
54	Distribution (Lines 33 and 45)	47,848,656		
55	Customer Accounts (Line 34)	23,908,109		
56	Customer Service and Informational (Line 35)	666,403		
57	Sales (Line 36)	174,781		
58	Administrative and General (Lines 37 and 46)	18,797,753		
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)	102,330,827	34,344,197	136,675,024
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	273,885,108	94,260,027	368,145,135
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	30,693,662	61,660,421	92,354,083
66	Gas Plant	12,444,976	24,321,088	36,766,064
67	Other (provide details in footnote):	998,647	2,978,059	3,976,706
68	TOTAL Construction (Total of lines 65 thru 67)	44,137,285	88,959,568	133,096,853
69	Plant Removal (By Utility Departments)			
70	Electric Plant	10,422,034	4,967,454	15,389,488
71	Gas Plant	1,832,427	2,258,595	4,091,022
72	Other (provide details in footnote):			
73	TOTAL Plant Removal (Total of lines 70 thru 72)	12,254,461	7,226,049	19,480,510
74	Other Accounts (Specify, provide details in footnote):			
75	LABOR BILLED TO OTHERS (143)	1,072,734	4,108,872	5,181,606
76	LABOR BILLED TO ASSOC CO (146)	10,224,665	2,793,630	13,018,295
77	STORES EXPENSE (163)	9,400,239	-8,870,305	529,934
78	CLEARING ACCOUNTS (184)	197,396,567	-196,694,008	702,559
79	DEFERRED DEBITS (186)	216,843	62,390	279,233
80	INJURIES AND DAMAGES (228)	3,440,285	349,853	3,790,138
81	JOB WORK (416)	1,962,040	7,833,959	9,795,999
82	NON UTILITY OPERATIONS (417)	231,505	196,957	428,462
83	OTHER INCOME DEDUCTIONS (426)	556,462	261,750	818,212
84	OTHER MISCELLANEOUS	19,006	-488,742	-469,736
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	224,520,346	-190,445,644	34,074,702
96	TOTAL SALARIES AND WAGES	554,797,200		554,797,200

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

1. Common Utility Plant in Service and Allocation of Common Utility Plant by Departments.

Acct No.	General Plant Account	Electric	Gas	Total
303.0	Misc Intangible Plant	74,427,019	70,868,608	145,295,627
389.1	Land	2,855,016	1,368,380	4,223,396
389.2	Right of Way	20,426	11,619	32,045
390.0	Structures & Improvements	79,376,175	66,670,146	146,046,321
390.1	Structures & Improvements - Leased	8,942,890	7,261,135	16,204,025
391.0	Office Furniture & Equipment	4,678,087	4,454,425	9,132,512
391.1	Office Furniture & Equipment - Mass	883,676	841,427	1,725,103
391.2	Computer Equipment	23,041,521	21,939,889	44,981,410
391.3	Computer Equipment - Mass	8,302,823	7,905,859	16,208,682
392.0	Transportation Equipment	2,009,411	1,913,340	3,922,751
392.3	Equipment Installed on Leased Vehicles	6,931	6,599	13,530
393.0	Stores Equipment	131,975	125,666	257,641
393.1	Stores Equipment - Mass	92,488	88,066	180,554
394.0	Tools, Shop & Garage Equipment	1,678,412	1,598,165	3,276,577
394.1	Tools, Shop & Garage Equipment - Mass	1,262,976	1,202,592	2,465,568
395.0	Laboratory Equipment	845,176	804,768	1,649,944
395.1	Laboratory Equipment - Mass	1,321,232	1,258,063	2,579,295
396.0	Power Operated Equipment	869,447	827,878	1,697,325
397.0	Communication Equipment	27,344,404	16,483,780	43,828,184
397.1	Communication Equipment - Mass	2,997,209	1,397,560	4,394,769
398.0	Miscellaneous Equipment	858,552	817,504	1,676,056
398.1	Miscellaneous Equipment - Mass	780,272	742,967	1,523,239
	Total	242,726,118	208,588,436	451,314,554

NOTE: Accounts 303, 389, 390, and 391 were allocated per Functional Use Surveys and the Customer Basis Percentages as of December 31, 2004 submitted to the Property Accounting Department.
Account 397 is allocated on the Radio Base Station Survey and the Customer Basis Percentages.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

2. Accumulated Provision for Depreciation and Amortization of Common Utility Plant & Changes During 2004:

Balance at Beginning of Year	242,020,210
Depreciation Accrual for 2004 Charged to:	
Account 403 Electric (A)	13,479,665
Account 404 Electric	1,646,825
Account 405 Electric	5,284,042
Account 403 Gas (A)	11,464,557
Account 404 Gas	1,523,220
Account 405 Gas	5,032,323
Total Depreciation Accrual	38,430,632
Net Charge for Plant Retired:	
Book Cost of Plant Retired	34,484,198
Cost of Removal	166,833
Salvage	(134,773)
Total Net Charges	34,516,258
Net Additions (Reductions) Resulting from Transfers and/or Adjustments of Property Between Departments	(382,054)
Balance at End of Year	245,552,530

Estimated Allocation of Common Utility Accumulated Provision for Depreciation at December 31, 2004: (B)

Electric	130,604,301
Gas	114,948,229
Total	245,552,530

3. Expenses Applicable to Common Utility Property are not Maintained as Such. These Expense are Generally Allocated via Clearing Accounts on the Basis of Floor Space Occupied, Hourly Use of Transportation and Other

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Equipment and the Basis of Electric and Gas Utilization.

(A) Account 403 Expenses Allocated Based on December 31, 2004 Common Utility Allocation of Original Cost by Department.

(B) Based on Decemeber 31, 2004 Common Utility Allocation of Original Cost by Department.

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. (These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations, rendered the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnership, organization of any kind, or individual [other than for services as an employee or for payments made for medical and related services] amounting to more than $25,000, including payments for legislative services, except those which should be reported in Account 426.4, Expenditures for Certain Civic, Political and Related Activities.)
(a) Name and address of person or organization rendering services,
(b) description of services received during year and project or case to which services relate,
(c) basis of charges,
(d) total charges for the year, detailing utility department and account charged.
2. For any services which are of a continuing nature, give the date and term of contract and date of Commission authorization, if contract received Commission approval.
3. Designate with an asterisk associated companies.

Line No.	Name and Address (a)	Description of Services (b)	Basis of Charges (c)	Charges for the Year (d) Amount	Dept/Account
1	A & K 22312 Garrison St Suite #2 Detroit, MI 48124-2228	Consulting Services	Fee & Expenses	63,900	920E, 921E&G
2	Acro Services Corporation 17187 N Laurel Park Drive Livonia, MI 48152	Technical Services	Fee & Expenses	8,265,990	Various
3	Administrative Controls 525 Avis Drive Suite #2 Ann Abor, MI 48108	Consulting Services	Fee & Expenses	388,997	184
4	AG&E Inc. 405-A Parkway Drive Greensboro, NC 2740 1116	Consulting/ Technical Services	Fee & Expenses	394,313	107E, 543E
5	AGP & Associates 6105 Jefferson Avenue Midland, MI 48640	Professional Advertising Services	Fee & Expenses	66,974	912G
6	Air Improvement Resources 47298 Sunnybrook Lane Suite 103 Novi, MI 48374	Consulting Services	Fee & Expenses	58,789	184
7	Apcompower Inc P O Box 392 Bath, MI 48808	Consulting Services	Fee & Expenses	367,856	107E
8	Arcadis G&M Inc 41511 Eleven Mile Road Dept 547 Novi, MI 48374	Consulting Services	Fee & Expenses	914,695	184
9	Babcock & Wilcox 20 S Vanburen Ave Barberton, OH 44203	Engineering/ Consulting Services	Fee & Expenses	22,984,675	107, 108, 512E
10	Barr Engineering Company 8300 Norman Center Drive Minneapolis, MN 55437 1026	Consulting/ Technical Services	Fee & Expenses	721,182	184, 543E
11	Barris Sott Denn & Driker 211 W Fort St 15th Floor Detroit, MI 48226	Consulting Services	Fee & Expenses	26,006	228E
12	Black & Veatch 2200 Commonwealth Blvd Ann Arbor, MI 48105	Engineering Services	Fee & Expenses	3,800,936	107E, 511E, 521E
13	Blasland, Bouck & Lee, Inc. 6723 Towpath Road P.O. Box 66 Syracuse, NY 13214-0066	Professional Services	Fee & Expenses	67,562	107E
14	Bleakley Cypher Parent Warren 50 Monroe N. W. Suite 700 East Grand Rapids, MI 49503	Legal Services	Fee & Expenses	92,658	228E&G
15	BP&R Engineering Inc 1161 6 Mile Road Comstock Park, MI 49321	Engineering Services	Fee & Expenses	727,668	184
16	Buford Goff & Associates 1331 Elmwood Ave Columbia, SC 29201	Engineering Services	Fee & Expenses	306,202	184
17	Chemithon Enterprises, Inc. 5430 W. Marginal Way SW Seattle, WA 98106-1598	Technical Consultant	Fee & Expenses	387,295	107E, 512E
18	Cleveland Inspection Services 6 Miles SE on HWY 64 Box 100 Cleveland OK 74020	Professional Services	Fee & Expenses	121,356	107E, 108E

19	* CMS Energy 330 Town Ctr Dr Fairlane Pl Dearborn, MI 48126	Management Services	Fee & Expenses	2,562,953	242 ,920 E&G, 923 E&G
20	* CMS Enterprises One Energy Plaza Jackson, MI 49201	Professional Services	Fee & Expenses	1,079,676	107, 146, 184, 228G, 426E, 920E&G, 921E&G, 923E&G
21	* CMS Enterprises - Datamart One Energy Plaza Jackson, MI 49201	Professional Services	Fee & Expenses	522,586	879E
22	Commonwealth Associates Inc P O Box 1124 Jackson, MI 49204	Consulting Services	Fee & Expenses	36,429	543E, 539E
23	Commonwealth Cultural Resources Group Inc. 2530 Spring Arbor Road Jackson, MI 49203	Technical Services	Fee & Expenses	33,497	107E, 537E
24	Corporate Vision Concepts 20096 76th Street South Haven, MI 49090	Technical Services	Fee & Expenses	118,850	184, 506E
25	Cummins & Barnard Inc 5405 Data Court Suite 100 Duluth, MN 55802	Consulting Services	Fee & Expenses	133,505	107E, 184, 511E
26	Deloitte & Touche 2200 Ross Ave, Suite 1600 Dallas, TX 6778	Consulting Services	Fee & Expenses	133,460	184, 923G
27	Dykema Gossett & Trigg 35th Floor 400 Renaissance CTR Detroit, MI 48243	Legal Services	Fee & Expenses	44,757	182E, 228E
28	Elexco Land Services 106 Huron BLDV Suite A Marysville, MI 48040	Consulting Services	Fee & Expenses	203,331	107, 184
29	Envirologic Technologies, Inc. 2960 Interstate Parkway Kalamazoo, MI 49048	Professional Consulting Services	Fee & Expenses	75,942	108E
30	Environmental Consulting & Technology 220 Bagley Ave, Suite 600 Detroit, MI 48226	Technical/ Consulting Services	Fee & Expenses	766,816	184G
31	Environmental Elements Corp. 3700 Koppers St. Baltimore, MD 21227	Engineering Services	Fee & Expenses	84,825	107
32	Environmental Solution Professional LLC 1240 Eagle Point Road Clark Lake, MI 49234	Consulting Services	Fee & Expenses	184,250	107E, 184
33	Environmental Systems Corporation 200 Tech Center Drive Knoxville, TN 37912	Consulting Services	Fee & Expenses	136,500	107E, 502E
34	Envision Telephony Inc. 520 Pike Street, Ste. 1600 Seattle, WA 98101	Professional Services	Fee & Expenses	79,296	107, 303
35	EPIC-MRA 4710 W. Saginaw Hwy, Ste. 5 Lansing, MI 48917	Professional Services	Fee & Expenses	27,700	146
36	Ernst & Young LLC 8484 Westpark Drive McLean, VA 22102	Consulting/ Audit Services	Fee & Expenses	2,398,776	146, 146E, 181, 184, 242 923E&G, 926E&G
37	* ES Services 212 West Michigan Ave Jackson, MI 49201	Professional/ Engineering Services	Fee & Expenses	1,603,981	107E, 184E
38	Exponent Inc P O Box 200283, Dept 002 Dallas, TX 75320	Consulting Services	Fee & Expenses	135,290	228E
39	Fitzgerald Henne & Assoc., Inc. 3125 Sovereign Dr., Ste. D Lansing, MI 48911	Consulting Services	Fee & Expenses	57,713	107E, 108E
40	Fossil Energy Research 23342 C South Pointe Laguna Hills, CA 92653	Engineering Services	Fee & Expenses	87,804	107E, 506E
41	Gartner Group P O Box 911319 Dallas, TX 753911	Consulting Services	Fee & Expenses	96,600	184
42	General Engineering Lab, LLC P.O. Box 30712 2040 Savage Road Charleston, SC 29417	Technical Services	Fee & Expenses	64,393	108, 108E
43	Golf Project Management Inc 1776 Park Trail NE Grand Rapids, MI 49526	Professional Services	Fee & Expenses	183,110	184E
44	Gourdie Fraser & Associates 124 West State St P O Box 927 Traverse City, MI 498685 0927	Professional/ Consulting/Survey Services	Fee & Expenses	65,011	184

45	Heath Consultants 100 Tosca Dr. Stoughton, MA 02072	Consulting Services	Fee & Expenses	378,005	874E&G
46	Hewitt Associates 100 Half Day Road Lincolnshire, IL 60015	Actuarial Services	Fee & Expenses	571,404	146, 184, 242, 923E&G 926, 926E&G
47	Holland Engineering, Inc. 418 East 8th Street Holland, MI 49423	Engineering Services	Fee & Expenses	575,492	107E&G, 856G
48	ISH Inc 690 Fremont Ave, Suite 3 Sunnyvale, CA 94087	Consulting Services	Fee & Expenses	144,009	184
49	Jacobs & Clevenger 401 N Wabash Suite 620 Chicago, IL 60601-1692	Consulting Services	Fee & Expenses	694,447	879G, 417G
50	James W Dempsey, Attorney At Law PLLC 3795 Maidstone Road Jackson, MI 49203	Legal Services	Fee & Expenses	38,706	228E
51	Jan X-Ray Services, Inc. 8500 E. Michigan Ave. Parma, MI 49269	Technical Consulting	Fee & Expenses	28,673	184
52	JMW3 LLC 2410 Heronwood Drive Bloomfield, MI 48302	Professional Consulting	Fee & Expenses	250,400	146, 920, 921, 923G
53	Kelley Drye & Warren 101 Park Ave New York, NY 10178	Professional Services	Fee & Expenses	42,022	181, 920E&G
54	Kleinschmidt & Associates 75 Main Street P O Box 576 Pittsfield, ME 04967	Technical/ Consulting Services	Fee & Expenses	155,146	537E, 539E
55	Krech Ojard & Assoc. 227 W. First Street, Ste. 200 Duluth, MN 55802	Professional Services	Fee & Expenses	26,455	107E
56	Lacey & Jones LLP 600 S Adams Road Suite 300 Birmingham, MI 48009	Legal Services	Fee & Expenses	38,473	228E&G
57	Lamps Inc 13760 Noel Road Suite 930 Dallas, TX 75240	Technical/ Engineering Services	Fee & Expenses	76,757	107E, 108E, 184E, 186 242G, 814, 850, 864
58	Larkin Enterprises Inc 17 Carriage Lane Hampden, ME 49202	Professional Services	Fee & Expenses	237,829	184
59	Lawler Matusky & Skelly Engineers LLP 10207 Lucas Road Woodstock, IL 60098	Consulting Services	Fee & Expenses	90,606	107E, 537E
60	Loadspring Solutions Inc. 15 Union Street #401 Lawrence, MA 01840	Technical Services	Fee & Expenses	76,620	184
61	Longenecker & Assoc., Inc. P.O. Box 3094 Del Mar, CA 92014	Consulting Services	Fee & Expenses	40,186	108E
62	Loomis Ewert Edere Parsley Davis & Gott 232 S Capitol Avenue, Suite 1000 Lansing, MI 48933	Legal Services	Fee & Expenses	1,165,213	182E, 923E
63	Louis Berger Group, Inc. 120 Halsted St. East Orange, NJ 07018	Technical Consulting Services	Fee & Expenses	74,584	537E
64	Mar/Tec 5437 Trager Road P O Box 3331 Traverse City, MI 49685	Consulting Services	Fee & Expenses	1,009,403	184
65	Marcoux Allen Abbott Schomer & Bower PC 145 S Jackson Street Jackson, MI 49201	Legal Services	Fee & Expenses	75,128	228E
66	Marshall & Stevens, Inc. 1011 E. Touhy Ave., Ste. 400 Des Plaines, IL 60018	Consulting Services	Fee & Expenses	25,542	923E&G
67	Material Testing Consultants 693 Plymouth NE Grand Rapids, MI 49505	Consulting Services	Fee & Expenses	138,144	107E, 501E, 543E
68	Mayer Brown Rowe & Maw LLP 190 S LaSalle Street Chicago, IL 60603	Legal Services	Fee & Expenses	32,453	920E&G, 921
69	Mc Alvey & Associates 120 West Ottawa Street Lansing, MI 48933	Consulting Services	Fee & Expenses	36,000	426, 580E
70	Meridian Consulting Group 5 Riverway #300 Houston, TX 77056	Professional Services	Fee & Expenses	233,342	184, 920E&G, 921E&G
71	Micon, Inc. 8950 South 52nd St., Ste. 210 Tempe, AZ 85284	Consulting Services	Fee & Expenses	343,474	184, 901G, 903E&G

72	Mid American Inspection SVCS 1206 Effie Road P O Box 1427 Gaylord, MI 49734	Technical Services	Fee & Expenses	113,931	184
73	Midwestern Audit Services 900 Wilshire, Ste. 350 Troy, MI 48084-1694	Collection Services	Fee & Expenses	575,492	107E&G, 856G
74	Miller Canfield Paddock & Stone 150 W Jefferson Detroit, MI 48226	Legal Services	Fee & Expenses	71,532	181, 920, 921, 923E
75	Mitsui Babcock Energy Services Limited P O Box 888194 Atlanta, GA 30356	Engineering Services	Fee & Expenses	176,783	107E
76	Morrow & Company, Inc. 909 Third Avenue Accounting Dept - 20th Floor New York, NY 10022	Professional Services	Fee & Expenses	124,186	184, 920E&G, 921E&G
77	Natural Resource Group Inc 1000 IDS Center 80 South Eight Street Minneapolis, MN 55402	Consulting Services	Fee & Expenses	89,100	107E
78	Natural Resource Technology 23713 W. Paul Road Pewaukee, WI 53072	Technical Consulting Services	Fee & Expenses	103,017	107E
79	NCO Financial Systems One Jackson Square, Suite 650 Jackson, MI 49202	Collection Services	Fee & Expenses	5,029,814	903E&G
80	Nexus Energy Software 233 Needham Street Newton, MA 02164	Technical Services	Fee & Expenses	256,749	903G, 909E
81	Niku Corporation Niku Education Services 305 Main Street Redwood City, CA 94063	Professional Services	Fee & Expenses	109,885	184
82	Novak Engineering Inc 2919 Wildwood Ave Jackson, MI 19202	Engineering Services	Fee & Expenses	105,111	107E
83	Nuclear Management Company 700 1st Street Hudson, WI 54016	Management Services	Fee & Expenses	142,071,902	135E, 232, 926
84	Parsons Engineering Inc. of Michigan 999 Oakmont Plaza Dr., Ste. 420 Westmont, IL 60559	Consulting Services	Fee & Expenses	59,841	146
85	Philip Environmental 210 W Sand Bank RD, P O Box 230 Columbia, IL 62236	Consulting Services	Fee & Expenses	71,713	184
86	Pillsbury Winthrop, LLP One Battery Park Plaza New York, NY 10004	Legal Services	Fee & Expenses	133,209	181, 920E&G
87	Price Waterhouse Cooper LLP 400 Renaissance Center Detroit, MI 48243	Consulting Services	Fee & Expense	3,150,016	146, 181, 920E&G, 923G
88	Resource Connection Inc 695 Town Center Drive Suite 600 Costa Mesa, CA 92626	Professional Services	Fee & Expenses	166,420	184
89	Risk Management, Inc. Board of Trade Building 141 W. Jackson Blvd., Ste. 1800A Chicago, IL 60093	Consulting Services	Fee & Expenses	84,000	851G, 920E&G, 921E&G
90	Robert Half International Inc 5720 Stoneridge Drive Suite 3 Pleasanton, CA 94588	Professional Services	Fee & Expenses	467,364	146, 184, 920E&G, 921E&G
91	Roose Service 2373 Musser Road Mancelona, MI 49659	Consulting Services	Fee & Expenses	66,929	107E, 816G, 832G
92	Sargent & Lundy 55 East Monroe Street Chicago, IL 60603	Professional Services	Fee & Expenses	413,768	107E, 146, 184E 920E&G, 921E&G
93	Sheridan Surveying Company 4629 Page Avenue Michigan Center, MI 49503	Survey Services	Fee & Expenses	144,260	184
94	Sigma Technologies 27421 Holiday Lane Perrysburg, OH 43551	Consulting Services	Fee & Expenses	728,079	184, 184E, 583, 584
95	Skadden Arps Slate Meagher Flom 919 Third Avenue New York, NY 10022-9931	Legal Services	Fee & Expenses	29,710	181, 920E&G
96	Soil and Material Testing 43980 Plymouth Oak BLVD Plymouth, MI 48170	Technical/ Consulting Services	Fee & Expenses	673,253	107E, 108E, 146, 184, 242E&G, 834G, 853G
97	South Bend Medical Foundation 530 N Lafayette Blvd South Bend, IN 46601	Professional Services	Fee & Expenses	36,032	108, 524E, 926E&G

98	SSOE Inc 1001 Madison Ave Toledo, OH 43624	Engineering Services	Fee & Expenses	251,764	107E
99	STS Consultants 7402 Westshire Drive Suite 100 Lansing, MI 48917	Consulting/ Engineering Services	Fee & Expenses	473,850	108E, 184, 502E
100	Sullivan Ward Bone Tyler & Asher PC 25800 Northwestern Hwy, Box 22 Southfield, MI 48037	Legal Services	Fee & Expenses	195,148	228E&G
101	TCF Leasing Inc 11100 Wayzata BLVD Suite 801 Minnetonka, MN 55305	Professional Services	Fee & Expenses	81,750	184
102	The Brattle Group, Inc. 44 Brattle Street Cambridge, MA 02138-3736	Consulting Services	Fee & Expenses	27,579	556E
103	Thielsch Engineering 195 Francis Avenue Cranston, RI 02910	Professional Engineering Services	Fee & Expenses	26,151	513
104	TLG Services Inc 148 New Milford Road East Bridgewater, CT 06752	Consulting Services	Fee & Expenses	81,937	108E, 923E
105	Venator Consulting Group, Inc. 888 W. Big Beaver Rd., Ste. 450 Troy, MI 48084	Professional Services	Fee & Expenses	62,110	146, 920E&G, 921E&G
106	Warner Norcross & Judd 2000 Town Center, Suite 2700 Southfield, MI 48075	Legal Services	Fee & Expenses	72,639	228E
107	Watson Wyatt & Company One Northern Plaza Suite 500 Southfield, MI 48034	Consulting Services	Fee & Expenses	467,963	146, 923E&G
108					
109			TOTAL	214,065,605	

SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES

1. In column (a) report the name of the associated company.
2. In column (b) describe the affiliation (percentage ownership, etc.).
3. In column (c) describe the nature of the goods and services provided (administrative and general expenses, dividends declared, etc.).
4. In columns (d) and (e) report the amount classified to operating income and the account(s) in which reported.

Line No.	Company (a)	Affiliation (b)	Description: Nature of Goods and Services (c)	Account Number (d)	Amount Classified to Operating Income (e)
				see Notes	
1	CMS Antrim Gas LLC	CMS Enterprises Sub, 100%	Professional Svcs, Emp Benefits	(1)	25,475
2	CMS Bay Area Pipeline LLC	CMS Enterprises Sub, 100%	Professional Svcs	(1)	14,658
3	CMS Capital LLC	CMS Enterprises Sub, 100%	Professional Svcs	(1)	67,715
4	CMS Electric and Gas LLC	CMS Enterprises Sub, 100%	Professional Svcs, Emp Benefits	(1)	6,708
5	CMS Energy Corporation	Parent Company	Professional Svcs, Emp Benefits	(1)	2,044,190
6	CMS Energy Resource Management Co	CMS Enterprises Sub, 100%	Professional Svcs, Emp Benefits	(1)	583,958
7	CMS Engineering Company	Consumers Sub, 100%	Professional Svcs	(1)	10,139
8	CMS Enterprises Company	CMS Energy Sub, 100%	Professional Svcs, Emp Benefits	(1)	2,370,699
9	CMS Gas Transmission Company	CMS Enterprises Sub, 100%	Professional Svcs, Emp Benefits	(1)	316,681
10	CMS Generation Company	CMS Enterprises Sub, 100%	Professional Svcs, Emp Benefits	(1)	514,842
11	CMS Generation Filer City Operating Co	CMS Enterprises Sub, 100%	Professional Svcs, Emp Benefits	(1)	5,417
12	CMS Generation Michigan Power LLC	CMS Enterprises Sub, 100%	Professional Svcs	(1)	337
13	CMS Generation Operating Company	CMS Enterprises Sub, 100%	Professional Svcs, Emp Benefits	(1)	57,767
14	CMS Generation Operating Co II, Inc	CMS Enterprises Sub, 100%	Professional Svcs, Emp Benefits	(1)	57,511
15	CMS Grands Lacs LLC	CMS Enterprises Sub, 100%	Professional Svcs	(1)	7,117
16	CMS International Operating Company	CMS Enterprises Sub, 100%	Emp Benefits	(1)	0
17	CMS International Ventures LLC	CMS Enterprises Sub, 98.5%	Professional Svcs, Emp Benefits	(1)	104,218
18	CMS Land Company	CMS Enterprises Sub, 100%	Professional Svcs	(1)	83,843
19	CMS Midland Holdings Company	Consumers Sub, 100%	Professional Svcs	(1)	9,406
20	CMS Midland, Inc	Consumers Sub, 100%	Professional Svcs	(1)	12,978
21	CMS Resource Development Company	CMS Enterprises Sub, 100%	Professional Svcs, Emp Benefits	(1)	6,097
22	CMS Texas LLC	CMS Enterprises Sub, 100%	Professional Svcs, Emp Benefits	(1)	3,138
23	Consumers Campus Holdings LLC	Consumers Sub, 100%	Professional Svcs	(1)	6,841
24	Consumers Nuclear Services LLC	Consumers Sub, 100%	Professional Svcs	(1)	70,109
25	Craven County Plant	CMS Enterprises, 50%	Professional Svcs	(1)	4,989
26	Dearborn Generation Operating LLC	CMS Enterprises Sub, 100%	Professional Svcs, Emp Benefits	(1)	27,100
27	Dearborn Industrial Generation Plant	CMS Energy, 100%	Professional Svcs	(1)	599
28	EnerBank U.S.A.	CMS Enterprises Sub, 100%	Professional Svcs, Constr Svcs Emp Benefits	(1)	194,434
29					
30	ES Services Company	Consumers Sub, 100%	Professional Svcs, Constr Svcs	(1)	758,384
31	Genesee Power Station	CMS Enterprises, 50%	Professional Svcs	(1)	(5,537)
32	Grayling Generating Station	CMS Enterprises, 50%	Professional Svcs	(1)	2,134
33	Jackson Pipeline Company	CMS Enterprises, 75%	Professional Svcs	(1)	11,483
34	MEC Development Corporation	Consumers Sub, 100%	Professional Svcs	(1)	1,793
35	Midland Cogeneration Venture	Consumers, 49%	Fac Cost, Gas Transp & Storage Property Lease, Property Taxes	(1), 489,495	12,760,648
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37	T.E.S Filer City Station	CMS Enterprises, 50%	Professional Svcs	(1)	4,430
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55	NOTES:				
56	(1) Accounts 920, 921, 923-926, 930,				
57	931, 935, 408, 456, 495				
58					20,140,301

SUMMARY OF COSTS BILLED TO ASSOCIATED COMPANIES (Continued)

5. In columns (f) and (g) report the amount classified to non-operating income and the account(s) in which reported.
6. In columns (h) and (i) report the amount classified to the balance sheet and the account(s) in which reported.
7. In column (j) report the total.
8. In column (k) indicate the pricing method (cost, per contract terms, etc.).

Account Number (f)	Amount Classified to Non-operating Income (g)	Account Number (h)	Amount Classified to Balance Sheet (i)	Total (j)	Pricing Method (k)	Line No.
419	841	146	198,024	224,340	Full Cost	1
419	306	146	37,193	52,157	Full Cost	2
419	2,504	146	292,107	362,326	Full Cost	3
419	535	146	24,924	32,167	Full Cost	4
419	79,736	146,184	18,753,165	20,877,091	Full Cost	5
419	9,086	146	1,386,101	1,979,145	Full Cost	6
419	147	146	12,434	22,720	Full Cost	7
419	47,030	146	9,177,694	11,595,423	Full Cost	8
419	9,055	146	1,591,881	1,917,617	Full Cost	9
419	23,597	146	1,900,999	2,439,438	Full Cost	10
419	1,250	146	595,353	602,020	Full Cost	11
419	13	146	2,055	2,405	Full Cost	12
419	2,981	146	715,067	775,815	Full Cost	13
419	1,788	146	324,099	383,398	Full Cost	14
419	81	146	26,040	33,238	Full Cost	15
419	398	146	62,906	63,304	Full Cost	16
419	3,611	146	492,781	600,610	Full Cost	17
419	3,533	146	709,704	797,080	Full Cost	18
419	131	146	11,906	21,443	Full Cost	19
419	205	146	20,706	33,889	Full Cost	20
419	1,066	146	156,309	163,472	Full Cost	21
419	329	146	48,106	51,573	Full Cost	22
419	92	146	8,144	15,077	Full Cost	23
419	1,725	146	82,775	154,609	Full Cost	24
419	77	146	8,529	13,595	Full Cost	25
419	3,495	146	482,511	513,106	Full Cost	26
419	10	146	19,385	19,994	Full Cost	27
419	11,188	146	867,850	1,073,472	Full Cost	28
						29
419	11,954	146	1,153,565	1,923,903	Full Cost	30
419	11	146	194,451	188,925	Full Cost	31
419	31	146	3,374	5,539	Full Cost	32
419	173	146	85,346	97,002	Full Cost	33
419	27	146	2,359	4,179	Full Cost	34
418, 419	450,624	146	513,563	13,724,835	Full Cost	35
						36
419	74	146	7,004	11,508	Full Cost	37
						38
						39
						40
						41
						42
						43
						44
						45
						46
						47
						48
						49
						50
						51
						52
						53
						54
						55
						56
						57
	667,704		39,968,410	60,776,415		58

SUMMARY OF COSTS BILLED FROM ASSOCIATED COMPANIES

1. In column (a) report the name of the associated company.
2. In column (b) describe the affiliation (percentage ownership, etc.).
3. In column (c) describe the nature of the goods and services provided (administrative and general expenses, dividends declared, etc.).
4. In columns (d) and (e) report the amount classified to operating income and the account(s) in which reported.

Line No.	Company (a)	Affiliation (b)	Description: Nature of Goods and Services (c)	Account Number (d)	Amount Classified to Operating Income (e)
1	CMS Bay Area Pipeline LLC	CMS Enterprises Sub, 100%	Gas Transportation	501	3,814,702
2					
3	CMS Energy Corporation	Parent Company	Corporate Costs, External Auditing Services, Restricted Stock	920,921,923	1,691,966
4					
5					
6					
7	CMS Energy Resource Management Co	CMS Enterprises Sub, 100%	Gas Purchases	803	2,028,562
8					
9	CMS Enterprises Company	CMS Energy Sub, 100%	Administrative Services	556,851,879	1,288,690
10			Datamart O&M	912,921,923	
11					
12	CMS Gas Transmission Company	CMS Enterprises Sub, 100%	Administrative Services	921	632
13					
14	CMS Generation Company	CMS Enterprises Sub, 100%	Administrative Services		
15					
16	CMS Land Company	CMS Enterprises Sub, 100%	Purchase of Substation Sites		
17					
18	ES Services Company	Consumers Sub, 100%	Engineering Services		
19					
20	Genesee Power Station	CMS Enterprises, 50%	Energy Purchases	555	15,946,667
21					
22	Grayling Generating Station	CMS Enterprises, 50%	Energy Purchases	555	17,848,546
23					
24	Midland Cogeneration Venture	Consumers, 49%	Energy Purchases	555	591,456,196
25					
26	T.E.S. Filer City Station	CMS Enterprises, 50%	Energy Purchases	555	32,978,511
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49	Total				667,054,472

SUMMARY OF COSTS BILLED FROM ASSOCIATED COMPANIES (Continued)

5. In columns (f) and (g) report the amount classified to non-operating income and the account(s) in which reported.
6. In columns (h) and (i) report the amount classified to the balance sheet and the account(s) in which reported.
7. In column (j) report the total.
8. In column (k) indicate the pricing method (cost, per contract terms, etc.).

Account Number (f)	Amount Classified to Non-operating Income (g)	Account Number (h)	Amount Classified to Balance Sheet (i)	Total (j)	Pricing Method (k)	Line No.
				3,814,702	Full Cost	1
						2
426	722,008	146,184,242	148,979	2,562,953	Full Cost	3
						4
						5
						6
		242	651,037	2,679,599	Full Cost	7
						8
426	75,487	107,146,181	154,865	1,519,042	Full Cost	9
		184,228				10
						11
				632	Full Cost	12
						13
		184	139,630	139,630	Full Cost	14
						15
		107	71,625	71,625	Full Cost	16
						17
416	1,735,949			1,735,949	Full Cost	18
						19
				15,946,667	Full Cost	20
						21
				17,848,546	Full Cost	22
						23
				591,456,196	Full Cost	24
						25
				32,978,511	Full Cost	26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46
						47
						48
	2,533,444		1,166,136	670,754,052		49

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	19,033,045
4	Nuclear	5,335,635
5	Hydro-Conventional	445,076
6	Hydro-Pumped Storage	1,333,581
7	Other	8,498
8	Less Energy for Pumping	1,872,029
9	Net Generation (Enter Total of lines 3 through 8)	24,283,806
10	Purchases	14,451,928
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	
17	Delivered	
18	Net Transmission for Other (Line 16 minus line 17)	
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	38,735,734

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	33,039,318
23	Requirements Sales for Resale (See instruction 4, page 311.)	426,418
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,515,010
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	17,436
27	Total Energy Losses	2,737,552
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	38,735,734

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MONTHLY PEAKS AND OUTPUT

(1) Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
(2) Report on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	3,396,290	155,620	5,615	6	1900
30	February	3,055,723	122,427	5,339	5	2000
31	March	3,378,584	392,098	5,076	16	2000
32	April	3,179,225	505,076	4,693	19	1100
33	May	3,243,289	419,583	5,288	12	1400
34	June	3,204,448	192,028	6,667	9	1200
35	July	3,394,989	160,131	6,958	21	1700
36	August	3,369,016	146,744	6,825	2	1500
37	September	3,162,722	85,068	6,279	15	1700
38	October	2,943,538	71,597	4,802	18	2000
39	November	3,029,303	200,663	5,209	29	1900
40	December	3,378,607	258,589	5,750	20	1900
41	TOTAL	38,735,734	2,709,624			

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Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Campbell 1 & 2* (b)			Plant Name: *Cobb 4-5* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1962			1956		
4	Year Last Unit was Installed	1967			1957		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	668.90			312.50		
6	Net Peak Demand on Plant - MW (60 minutes)	631			346		
7	Plant Hours Connected to Load	8784			8784		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	620			320		
10	When Limited by Condenser Water	615			312		
11	Average Number of Employees	143			104		
12	Net Generation, Exclusive of Plant Use - KWh	4052510100			2092083200		
13	Cost of Plant: Land and Land Rights	1949688			113291		
14	Structures and Improvements	75844442			19529174		
15	Equipment Costs	304741053			111011037		
16	Asset Retirement Costs	0			0		
17	Total Cost	382535183			130653502		
18	Cost per KW of Installed Capacity (line 17/5) Including	571.8870			418.0912		
19	Production Expenses: Oper, Supv, & Engr	2857362			2247317		
20	Fuel	59932254			33377160		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	2274460			2246657		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1494934			919656		
26	Misc Steam (or Nuclear) Power Expenses	1560313			1068681		
27	Rents	0			0		
28	Allowances	1390902			1020280		
29	Maintenance Supervision and Engineering	1233848			857250		
30	Maintenance of Structures	588527			1104971		
31	Maintenance of Boiler (or reactor) Plant	5677013			3514806		
32	Maintenance of Electric Plant	1295172			1726616		
33	Maintenance of Misc Steam (or Nuclear) Plant	424987			171142		
34	Total Production Expenses	78729772			48254536		
35	Expenses per Net KWh	0.0194			0.0231		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Mcf	
38	Quantity (Units) of Fuel Burned	2051500	9561	0	1127439	176295	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	19649454	5838000	0	18661692	1017998	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	25.894	46.221	0.000	29.566	6.678	0.000
41	Average Cost of Fuel per Unit Burned	26.983	46.221	0.000	27.759	6.678	0.000
42	Average Cost of Fuel Burned per Million BTU	1.373	7.917	0.000	1.487	6.560	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.014	0.000	0.000	0.015	0.001	0.000
44	Average BTU per KWh Net Generation	9961.000	0.000	0.000	10143.000	0.000	0.000

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Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Whiting* (d)	Plant Name: *Kam 1 & 2* (e)	Plant Name: *Kam 3 & 4* (f)	Line No.
Steam	Steam	Steam	1
Conventional	Conventional	Conventional	2
1952	1959	1975	3
1953	1961	1977	4
317.80	544.00	1402.30	5
336	519	1221	6
8786	8762	868	7
0	0	0	8
328	515	1276	9
328	515	1276	10
122	128	99	11
2457992000	3372548000	223510000	12
474666	178947	50886	13
20538134	22011449	34089600	14
105465224	285620269	241433743	15
0	0	0	16
126478024	307810665	275574229	17
397.9799	565.8284	196.5159	18
1627831	2889776	1536233	19
40089024	52721561	20680794	20
0	0	0	21
2466667	1885399	1159793	22
0	0	0	23
0	0	0	24
1154573	1394343	902971	25
945994	1512016	962189	26
0	0	0	27
900449	334673	294443	28
1151703	1148706	415192	29
832298	932108	530730	30
2807449	6517422	1766699	31
864325	4158222	1106823	32
83142	265371	331300	33
52923455	73759597	29687167	34
0.0215	0.0219	0.1328	35

Coal	Oil		Coal	Oil	Gas	Gas	Oil		
Tons	Barrels		Tons	Barrels	Mcf	Mcf	Barrels		
1395897	7449	0	1753273	22732	46028	647716	467642	0	38
18533304	5880000	0	18994230	5796000	1025009	1041655	6319188	0	39
27.138	53.508	0.000	26.952	50.098	7.984	12.185	29.827	0.000	40
27.168	53.508	0.000	27.905	50.098	7.984	12.185	25.403	0.000	41
1.466	9.100	0.000	1.469	8.643	7.789	11.698	4.020	0.000	42
0.015	0.000	0.000	0.015	0.000	0.000	0.035	0.093	0.000	43
10543.000	0.000	0.000	9928.000	0.000	0.000	0.000	16240.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Weadock 7 & 8* (b)			Plant Name: *BCCobb 1-3* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1955			1948		
4	Year Last Unit was Installed	1958			1950		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	312.50			207.00		
6	Net Peak Demand on Plant - MW (60 minutes)	317			0		
7	Plant Hours Connected to Load	8177			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	310			183		
10	When Limited by Condenser Water	302			183		
11	Average Number of Employees	122			18		
12	Net Generation, Exclusive of Plant Use - KWh	1939518800			0		
13	Cost of Plant: Land and Land Rights	144060			0		
14	Structures and Improvements	22932473			62857		
15	Equipment Costs	83811728			24895866		
16	Asset Retirement Costs	0			0		
17	Total Cost	106888261			24958723		
18	Cost per KW of Installed Capacity (line 17/5) Including	342.0424			120.5735		
19	Production Expenses: Oper, Supv, & Engr	1637164			262947		
20	Fuel	28959599			452		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1560361			314014		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1281447			145022		
26	Misc Steam (or Nuclear) Power Expenses	1173244			33769		
27	Rents	0			0		
28	Allowances	815711			0		
29	Maintenance Supervision and Engineering	322940			106379		
30	Maintenance of Structures	694681			24438		
31	Maintenance of Boiler (or reactor) Plant	4842208			78765		
32	Maintenance of Electric Plant	4261592			177476		
33	Maintenance of Misc Steam (or Nuclear) Plant	320581			6025		
34	Total Production Expenses	45869528			1149287		
35	Expenses per Net KWh	0.0237			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Gas	Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels	Mcf	Mcf		
38	Quantity (Units) of Fuel Burned	985227	5729	103473	671	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	19548647	5752969	1000000	1017696	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	26.690	51.164	8.827	6.850	0.000	0.000
41	Average Cost of Fuel per Unit Burned	26.661	51.164	8.827	6.850	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.364	8.894	8.827	6.731	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.014	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10001.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Campbell 3 (Total)* (d)	Plant Name: *Campbell 3 (CPCo)* (e)	Plant Name: (f)	Line No.
Steam	Steam		1
Conventional	Conventional		2
1980	1980		3
1980	1980		4
871.25	812.96	0.00	5
850	793	0	6
8035	0	0	7
0	0	0	8
820	765	0	9
0	0	0	10
157	0	0	11
5327099000	4894882600	0	12
1748580	1748580	0	13
205947207	196631378	0	14
453241728	423755698	0	15
0	0	0	16
660937515	622135656	0	17
758.6083	765.2722	0.0000	18
0	2042620	0	19
0	69802283	0	20
0	0	0	21
0	1544746	0	22
0	0	0	23
0	0	0	24
0	1270955	0	25
0	1350538	0	26
0	0	0	27
0	2252143	0	28
0	725823	0	29
0	494581	0	30
0	4809211	0	31
0	608226	0	32
0	630711	0	33
0	85531837	0	34
0.0000	0.0175	0.0000	35

			Coal	Oil					36
			Tons	Barrels					37
0	0	0	2349782	14320	0	0	0	0	38
0	0	0	20484994	5838000	0	0	0	0	39
0.000	0.000	0.000	30.673	46.624	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	29.343	46.624	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	1.432	7.986	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.014	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	9851.000	0.000	0.000	0.000	0.000	0.000	44

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Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Weadock* (b)			Plant Name: *Thetford* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine Peaker			Gas Turbine Peaker		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1968			1970		
4	Year Last Unit was Installed	1969			1971		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	18.60			222.15		
6	Net Peak Demand on Plant - MW (60 minutes)	13			158		
7	Plant Hours Connected to Load	17			37		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	17			234		
10	When Limited by Condenser Water	17			234		
11	Average Number of Employees	0			6		
12	Net Generation, Exclusive of Plant Use - KWh	164800			863080		
13	Cost of Plant: Land and Land Rights	0			126313		
14	Structures and Improvements	4512			432225		
15	Equipment Costs	1610073			27306258		
16	Asset Retirement Costs	0			0		
17	Total Cost	1614585			27864796		
18	Cost per KW of Installed Capacity (line 17/5) Including	86.8056			125.4323		
19	Production Expenses: Oper, Supv, & Engr	3175			16724		
20	Fuel	13090			220659		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1482			67792		
26	Misc Steam (or Nuclear) Power Expenses	375			13288		
27	Rents	0			0		
28	Allowances	0			3424		
29	Maintenance Supervision and Engineering	2709			23391		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	2477			457960		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	23308			803238		
35	Expenses per Net KWh	0.1414			0.9307		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)			Gas			Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)			Mcf			Mcf
38	Quantity (Units) of Fuel Burned	0	0	2113	0	0	32246
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	1012305	0	0	1000031
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	6.195	0.000	0.000	6.843
41	Average Cost of Fuel per Unit Burned	0.000	0.000	6.195	0.000	0.000	6.843
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	6.120	0.000	0.000	6.843
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.079	0.000	0.000	0.256
44	Average BTU per KWh Net Generation	0.000	0.000	12979.000	0.000	0.000	37362.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Whiting* (d)	Plant Name: *Morrow* (e)	Plant Name: *Gaylord* (f)	Line No.
Gas Turbine Peaker	Gas Turbine Peaker	Gas Turbine Peaker	1
Conventional	Conventional	Conventional	2
1968	1968	1966	3
1968	1969	1968	4
18.60	36.00	82.60	5
14	29	69	6
11	11	176	7
0	0	0	8
17	34	85	9
17	34	85	10
0	0	6	11
97000	173900	6311000	12
0	0	1252	13
42801	6579	207377	14
1683657	3417387	6992278	15
0	0	0	16
1726458	3423966	7200907	17
92.8203	95.1102	87.1781	18
1869	3351	129057	19
8739	23152	1050809	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
1228	12434	74290	25
221	1101	36362	26
0	0	0	27
0	0	0	28
2218	2747	108041	29
0	185	16858	30
0	0	0	31
390821	21045	262283	32
0	0	0	33
405096	64015	1677700	34
4.1762	0.3681	0.2658	35

		Oil			Gas			Gas	
		Barrels			Mcf			Mcf	
0	0	286	0	0	2834	0	0	109186	38
0	0	5838487	0	0	1067395	0	0	1000000	39
0.000	0.000	30.576	0.000	0.000	8.169	0.000	0.000	9.373	40
0.000	0.000	30.576	0.000	0.000	8.169	0.000	0.000	9.373	41
0.000	0.000	5.239	0.000	0.000	7.654	0.000	0.000	9.373	42
0.000	0.000	0.090	0.000	0.000	0.133	0.000	0.000	0.166	43
0.000	0.000	17195.000	0.000	0.000	17395.000	0.000	0.000	17300.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Straits* (b)			Plant Name: *Campbell* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine Peaker			Gas Turbine Peaker		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1969			1968		
4	Year Last Unit was Installed	1969			1968		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	21.25			18.60		
6	Net Peak Demand on Plant - MW (60 minutes)	17			5		
7	Plant Hours Connected to Load	73			1		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	21			0		
10	When Limited by Condenser Water	21			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	882700			4700		
13	Cost of Plant: Land and Land Rights	4694			0		
14	Structures and Improvements	50816			14999		
15	Equipment Costs	2027852			1670964		
16	Asset Retirement Costs	0			0		
17	Total Cost	2083362			1685963		
18	Cost per KW of Installed Capacity (line 17/5) Including	98.0406			90.6432		
19	Production Expenses: Oper, Supv, & Engr	17009			90		
20	Fuel	139035			389		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	12339			5220		
26	Misc Steam (or Nuclear) Power Expenses	3904			11		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	13945			74		
30	Maintenance of Structures	1587			87		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	28493			33353		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	216312			39224		
35	Expenses per Net KWh	0.2451			8.3455		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)			Gas			Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)			Mcf			Barrels
38	Quantity (Units) of Fuel Burned	0	0	16587	0	0	12
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	1000000	0	0	5847059
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	8.382	0.000	0.000	32.004
41	Average Cost of Fuel per Unit Burned	0.000	0.000	8.382	0.000	0.000	32.004
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	8.382	0.000	0.000	5.476
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.157	0.000	0.000	0.083
44	Average BTU per KWh Net Generation	0.000	0.000	18791.000	0.000	0.000	15106.000

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Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Palisades* (d)	Plant Name: *Big Rock* (e)	Plant Name: (f)	Line No.
Nuclear	Nuclear		1
Conventional	Conventional		2
1970	1962		3
1970	1962		4
811.75	75.00	0.00	5
806	0	0	6
7166	0	0	7
792	0	0	8
803	0	0	9
767	0	0	10
536	104	0	11
5335635000	0	0	12
2566108	0	0	13
188060131	0	0	14
645959791	0	0	15
0	0	0	16
836586030	0	0	17
1030.5957	0.0000	0.0000	18
13185146	0	0	19
19724960	0	0	20
4676138	0	0	21
12428650	0	0	22
0	0	0	23
0	0	0	24
5599915	0	0	25
37912592	0	0	26
598360	0	0	27
0	0	0	28
10945443	0	0	29
855567	0	0	30
27894724	0	0	31
7485874	0	0	32
3404625	0	0	33
144711994	0	0	34
0.0271	0.0000	0.0000	35

Nuclear									36
KG of									37
750	0	0	0	0	0	0	0	0	38
58931098	0	0	0	0	0	0	0	0	39
1114.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
26300.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.335	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.004	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
11023.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000	0.0000
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0 0 0	0 0 0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0 0 0	0 0 0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000 0.000 0.000	0.000 0.000 0.000
41	Average Cost of Fuel per Unit Burned	0.000 0.000 0.000	0.000 0.000 0.000
42	Average Cost of Fuel Burned per Million BTU	0.000 0.000 0.000	0.000 0.000 0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000 0.000 0.000	0.000 0.000 0.000
44	Average BTU per KWh Net Generation	0.000 0.000 0.000	0.000 0.000 0.000

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Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0.0000	0.0000	0.0000	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: 20 Column: b

JHC 1&2
Includes ash, fuel handling and other non-fuel clause expenses in the amount of $4,135,501.

Schedule Page: 402 Line No.: 20 Column: c

BCCobb 4&5
Includes ash, fuel handling and other non-fuel clause expenses in the amount of $903,297.

Schedule Page: 402 Line No.: 20 Column: d

JRWhiting 1-3
Includes ash, fuel handling and other non-fuel clause expenses in the amount of $1,787,225.

Schedule Page: 402 Line No.: 20 Column: e

Karn 1&2 -
Includes ash, fuel handling and other non-fuel clause expenses in the amount of $2,294,535.

Schedule Page: 402 Line No.: 20 Column: f

Karn 3&4 -
Includes ash, fuel handling and other non-fuel clause expenses in the amount of $906,412.

Schedule Page: 402 Line No.: 28 Column: b

Line 28 - Expenses from Account 509.100 only.

Schedule Page: 402 Line No.: 28 Column: c

Line 28 - Expenses from Account 509.100 only.

Schedule Page: 402 Line No.: 28 Column: d

Line 28 - Expenses from Account 509.100 only.

Schedule Page: 402 Line No.: 28 Column: e

Line 28 - Expenses from Account 509.100 only.

Schedule Page: 402 Line No.: 28 Column: f

Line 28 - Expenses from Account 509.100 only.

Schedule Page: 402.1 Line No.: -1 Column: d

J H Campbell Unit 3 is jointly owned by Consumers Energy Company, Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. Consumers Energy Company is the operator of Campbell 3. Information in Column (d), lines 1 through 18 is for the entire plant. Information in Column (e), lines 5 through 12 reflect Consumers Energy Company's 93.31% undivided interest in the plant. Lines 13 through 35 reflect the costs and expenses of the plant as shown on Consumers Energy Company's books. Plant investment reflects the amount in service at December 31, 2004.

Schedule Page: 402.1 Line No.: 20 Column: b

Schedule Page: 402.1 Line No.: 20 Column: b
JCWeadock -
Includes ash, fuel handling and other non-fuel cluase expenses in the amount of $1,487,739.

Schedule Page: 402.1 Line No.: 20 Column: e

JHCampbell 3 (Consumers Share)-
Includes ash, fuel handling, and other non-fuel clause expenses in the amount of $192,981.

Schedule Page: 402.1 Line No.: 28 Column: e

Line 28 - Expenses from Account 509.100 only.

Schedule Page: 402.2 Line No.: 28 Column: c

Line 28 - Expenses from Account 509.100 only.

Schedule Page: 402.3 Line No.: -1 Column: d

RESPONSE TO INSTRUCTION 12

A. The Company owned two nuclear power generating plants. The Palisades Plant's operating and costs of generating power were charged to the applicable operation and

maintenance accounts as prescribed by the Federal Energy Regulatory Commission. The Big Rock Point Plant was retired August 97 and is being decommissioned.

B. The Company is charging Fuel Expense for the costs of fabrication, material and lease* costs on the basis of recognizing the total amount of such costs over the estimated useful life of the fuel. Each accounting period's charges are based on the estimated useful life expired during that period as expressed in megawatt days per metric ton. Fabrication and material are assigned equally to each fuel assembly in each batch of like fuel elements. Perpetual storage was charges to Fuel Expense in the same manner as fabrication and material until April 7, 1983. Since then, perpetual storage is charged to Fuel Expense based on the Department of Energy's contracted rate of one mill/kWh of net generation. This is a result of the Nuclear Waste Policy Act of 1982. Unburned fuel in the Big Rock Point Plant reactor at the time of plant shutdown was charged to fuel expense in 1997.

* Note: Starting in November 2001 Fuel is purchased and capitalized on the basis of useful life.

C. The Palisades Plant has a pressurized water reactor and uses uranium dioxide for fuel.

The Company has a full-term, 40-year operating license for the Palisades Nuclear Plant. Palisades license expires in the year 2011.

D. The National Energy Policy Act of 1992 established an additional nuclear fuel expense for decontamination and decommissioning of Department of Energy enrichment facilities. The expense is recovered at the rate of 1/12 the annual fee per month.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2452 Plant Name: HARDY (b)	FERC Licensed Project No. 2599 Plant Name: HODENPYL (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1931	1925
4	Year Last Unit was Installed	1931	1925
5	Total installed cap (Gen name plate Rating in MW)	30.00	15.10
6	Net Peak Demand on Plant-Megawatts (60 minutes)	33	10
7	Plant Hours Connect to Load	6,229	8,784
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	32	18
10	(b) Under the Most Adverse Oper Conditions	4	2
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	113,154,000	34,207,700
13	Cost of Plant		
14	Land and Land Rights	332,260	40,721
15	Structures and Improvements	908,598	559,817
16	Reservoirs, Dams, and Waterways	5,443,091	3,459,452
17	Equipment Costs	2,089,013	1,972,599
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	8,772,962	6,032,589
21	Cost per KW of Installed Capacity (line 20 / 5)	292.4321	399.5092
22	Production Expenses		
23	Operation Supervision and Engineering	52,640	15,914
24	Water for Power	64,991	31,990
25	Hydraulic Expenses	121,789	115,981
26	Electric Expenses	91,545	100,228
27	Misc Hydraulic Power Generation Expenses	49,171	19,675
28	Rents	0	0
29	Maintenance Supervision and Engineering	21,235	11,449
30	Maintenance of Structures	22,061	2,809
31	Maintenance of Reservoirs, Dams, and Waterways	111,463	57,833
32	Maintenance of Electric Plant	125,497	28,208
33	Maintenance of Misc Hydraulic Plant	7,534	8,559
34	Total Production Expenses (total 23 thru 33)	667,926	392,646
35	Expenses per net KWh	0.0059	0.0115

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2580 Plant Name: TIPPY (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1918			3
1918			4
20.10	0.00	0.00	5
16	0	0	6
8,784	0	0	7
			8
21	0	0	9
5	0	0	10
7	0	0	11
60,900,000	0	0	12
			13
4,380	0	0	14
677,119	0	0	15
4,930,360	0	0	16
2,018,455	0	0	17
13,383	0	0	18
0	0	0	19
7,643,697	0	0	20
380.2834	0.0000	0.0000	21
			22
28,331	0	0	23
38,056	0	0	24
227,552	0	0	25
93,867	0	0	26
52,660	0	0	27
0	0	0	28
15,387	0	0	29
8,660	0	0	30
49,227	0	0	31
9,545	0	0	32
14,453	0	0	33
537,738	0	0	34
0.0088	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 2680 Plant Name: LUDINGTON (Total) (b)
1	Type of Plant Construction (Conventional or Outdoor)	Conventional
2	Year Originally Constructed	1973
3	Year Last Unit was Installed	1973
4	Total installed cap (Gen name plate Rating in MW)	1,978
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	1,758
6	Plant Hours Connect to Load While Generating	4,174
7	Net Plant Capability (in megawatts)	1,872
8	Average Number of Employees	38
9	Generation, Exclusive of Plant Use - Kwh	2,764,264,000
10	Energy Used for Pumping	3,877,248,000
11	Net Output for Load (line 9 - line 10) - Kwh	-1,112,984,000
12	Cost of Plant	
13	Land and Land Rights	4,872,559
14	Structures and Improvements	35,347,688
15	Reservoirs, Dams, and Waterways	213,782,543
16	Water Wheels, Turbines, and Generators	84,986,170
17	Accessory Electric Equipment	16,426,024
18	Miscellaneous Powerplant Equipment	3,723,645
19	Roads, Railroads, and Bridges	3,398,333
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	362,536,962
22	Cost per KW of installed cap (line 21 / 4)	183.2105
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 2680 Plant Name: LUDINGTON (CPCo %) (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
Conventional			1
1973			2
1973			3
1,009			4
897			5
			6
955			7
			8
1,333,581,000			9
1,872,029,000			10
-538,448,000			11
			12
2,439,473			13
16,900,856			14
97,934,560			15
41,573,705			16
2,888,087			17
1,862,630			18
1,535,548			19
			20
165,134,859			21
163.6295			22
			23
514,375			24
825,259			25
147,513			26
525,813			27
450,060			28
84			29
204,907			30
58,414			31
498,471			32
1,143,901			33
763,043			34
5,131,840			35
29,028,797			36
34,160,637			37
0.0256			38

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FOOTNOTE DATA

Schedule Page: 408 Line No.: -1 Column: b

*The Ludington Project is jointly owned by joint licensees Consumers Energy Company and The Detroit Edison Company. Consumers Energy Company is the operator of the project. Information in column (b), Lines 1 through 22, is for entire Plant. Information in Column (c), Lines 4 through 11, reflects Consumers Energy Company's 51% undivided interest in the Plant. Lines 13 through 38 reflect the costs and expenses of the Plant as shown on Consumers Energy Company's books. Plant investment reflects the amount in service at December 31, 2004.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydraulic:					
2	Foote - FPC #2436	1918	9.00	9.6	30,161,500	4,344,008
3	Cooke - FPC #2450	1911	9.00	7.0	25,952,000	3,198,231
4	Five Channels - FPC #2453	1912	6.00	5.9	23,340,400	3,781,679
5	Loud - FPC #2449	1913	4.00	4.8	17,391,512	3,248,688
6	Alcona - FPC #2447	1924	8.00	7.8	26,469,300	3,756,694
7	Mio - FPC #2448	1916	4.96	4.2	14,105,000	3,387,560
8	Croton - FPC #2468	1907	8.85	8.1	42,938,200	8,727,882
9	Rogers - FPC #2451	1906	6.76	7.7	30,357,600	5,135,399
10	Webber - FPC #2566	1907	4.30	3.2	13,051,400	6,940,029
11	Calkins Bridge (Allegan) - FPC #785	1938	2.55	2.3	13,047,000	1,985,094
12						
13						
14						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
482,667	174,439		167,399			2
355,359	290,015		188,265			3
630,280	433,309		658,213			4
812,172	203,637		73,066			5
469,587	213,116		57,186			6
682,976	239,154		48,669			7
986,201	408,870		191,842			8
759,674	126,989		114,793			9
1,613,960	147,010		160,520			10
778,468	145,189		57,310			11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
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						45
						46

STEAM-ELECTRIC GENERATING PLANTS

1. Include on this page steam-electric plants of 25,000 Kw (name plate rating) or more of installed capacity.
2. Report the information called for concerning generating plants and equipment at year end. Show unit type installation, boiler, and turbine-generator on same line.
3. Exclude plant, the book cost of which is included in Account 121, *Nonutility Property*.
4. Designate any generating plant or portion thereof for which the respondent is not the sole owner. If such property is leased from another company give name of lessor, date and term of lease, and annual rent. For any generating plant, other than a leased plant or portion thereof for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining thearrangement and giving details as to such matters as percent ownership by respondent, name of co-owner, basis of sharing output, expenses or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.
5. Designate any generating plant or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent, and how determined. Specify whether lessee is an associated company.
6. Designate any plant or equipment owned, not

Line No.	Name of Plant (a)	Location of Plant (b)	BOILERS (Include both ratings for the boiler and the turbine-generator of dual-rated installations) Number and Year Installed (c)	Kind of Fuel and Method of Firing (d)	Rated Pressure (In psig) (e)	Steam Temperature (Indicate reheat boilers as 1050/1000) (f)	Rated Maximum Continuous M lbs Steam per Hour (g)
1	Palisades (Nuclear)	Covert Township	1 - 1972	Nuclear	2,085*	514**	11,200**
2							
3	J H Campbell	West Olive	1 - 1962	Coal-Pulverized	2,700	1050/1000	1,925
4							
5			1 - 1967	Coal-Pulverized	3,800	1000/1000	2,550
6			1 - 1980 (1)	Coal-Pulverized	2,900	1005/1005	6,000
7							
8	B C Cobb	Muskegon	1 - 1949 (2)	Gas	950	900	600
9			1 - 1949 (2)	Gas	950	900	600
10			1 - 1949 (2)	Gas	950	900	600
11			1 - 1956	Coal-Pulverized	2,300	1050/1000	1,050
12			1 - 1957	Coal-Pulverized	2,300	1050/1000	1,050
13							
14	D E Karn	Essexville	1 - 1959	Coal-Pulverized	2,725	1050/1050	1,750
15							
16			1 - 1961	Coal-Pulverized	2,700	1050/1000	1,750
17							
18			1 - 1975	Crude & Residual Oil & Natural Gas	2,250	955/955	4,625
19							
20			1 - 1977	Crude, Residual & Natural Gas	2,250	955/955	4,625
21							
22							
23	J C Weadock	Essexville	1 - 1955	Coal-Pulverized	2,300	1050/1000	1,050
24			1 - 1958	Coal-Pulverized	2,300	1050/1000	1,050
25							
26	J R Whiting	Near Erie	1 - 1952	Coal-Pulverized	1,650	1000/1000	690
27			1 - 1952	Coal-Pulverized	1,650	1000/1000	690
28			1 - 1953	Coal-Pulverized	1,650	1000/1000	850
29							
30	See Note (1) and (2) on Page 413C						
31							

* Primary system pressure ** Steam generator output

STEAM-ELECTRIC GENERATING PLANTS (Continued)

operated, and not leased to another company. If such a plant or equipment was not operated within the past year, explain whether it has been retired in the books of accounts or what disposition of the plant or equpment and its book cost are contemplated.
7. Report gas-turbines operated in a combined cycle with a conventional steam unit with its associated steam unit.

TURBINE-GENERATORS

(Report cross-compound turbine-generator units on two lines - H.P. section and I.P. section. Designate units with shaft connected boiler feed pumps. Give capacity rating of pumps pumps in terms of full load requirements)

	TURBINES (Include both ratings for the boiler and the turbine-generator of dual-rated installations.)				GENERATORS							
					Nameplate Rating in Megawatts							
Year Installed	Max. Rating Mega-watt	Type (Indicate tandem-compound (TC); cross-compound (CC); single casing (SC); topping unit (T); and noncondens-ing (NC) Show back pressures)	Steam Pressure at Throttle psig.	RPM	At Minimum Hydrogen Pressure	At Maximum Hydrogen Pressure (Include both ratings for the boiler and the turbine-generator of dual-rated installations)	Hydrogen Pressure (Designate air cooled generators)		Power Factor	Voltage (in KV) (If other than 3 phase, 60 cycle, indicate other charac-teristic)	Plant Capacity, Maximum Generator Nameplate Rating (Should agree with Column (n))	Line No.
							Min.	Max.				
(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	
1972	811.7	TC	720	1800	-	811.7	0.5	75.0	0.85	22.0	811.7	1
												2
1962	265	CC	2400	3600	97.4 +	132.5	25.0	45.0	0.85	16.0		3
					97.4 +	132.5	25.0	45.0	0.85	16.0		4
1967	403.9	TC	3500	3600	325.2	403.9	30.0	60.0	0.85	20.0		5
1980	871.3	TC	2400	3600	583.7	871.3	30.0	75.0	0.85	18.0	1,540.2	6
												7
1949	69	TC	850	3600	60	69	0.5	15.0	0.85	14.4		8
1949	69	TC	850	3600	60	69	0.5	15.0	0.85	14.4		9
1949	69	TC	850	3600	60	69	0.5	15.0	0.85	14.4		10
1956	156.3	TC	2000	3600	125	156.3	0.5	30.0	0.85	18.0		11
1957	156.3	TC	2000	3600	125	156.3	0.5	30.0	0.85	18.0	519.6	12
												13
1959	272	CC	2400	3600	108.8	136	25.0	45.0	0.85	16.0		14
					108.8	136	25.0	45.0	0.85			15
1961	272	CC	2400	3600	108.8	136	25.0	45.0	0.85	16.0		16
					108.8	136	25.0	45.0	0.85			17
1975	692.5	TC	1800	3600	387.8	692.5	15.0	60.0	0.85	26.0		18
												19
1977	709.8	TC	1800	3600	518	709.8	45.0	75.0	0.85	26.0	1,946.3	20
												21
1955	156.3	TC	2000	3600	125	156.3	0.5	30.0	0.85	18.0		22
1958	156.3	TC	2000	3600	125	156.3	0.5	30.0	0.85	18.0	312.6	23
												24
												25
1952	106.3	TC	1450	3600	85	106.3	0.5	30.0	0.85	14.4		26
1952	106.3	TC	1450	3600	85	106.3	0.5	30.0	0.85	14.4		27
1953	132,8	TC	1450	3600	106.3	132.8	0.5	30.0	0.85	15.5	345.5	28
												30
												31

+ J H Campbell - Shaft connected boiler feed pumps - 4,320 hp per pump - one each turbine.

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STEAM-ELECTRIC GENERATING PLANTS (Continued)

(1) Respondent, Michigan Public Power Agency and Wolverine Power Supply Cooperative, nonassociated companies, are co-owners, as tenants in common, of the J H Campbell No 3 unit with Respondent having a 93.31% undivided interest, Michigan Public Power Agency a 4.80% undivided interest, Wolverine Power Supply Cooperative a 1.89% undivided interest. Respondent is operator of the plant and is responsible for operation and maintenance. Respondent and the other owners are entitled to the generating capability and energy output of the unit in the percentages indicated above. Respondent and Michigan Public Power Agency also are co-owners, as tenants in common, of substation and certain transmission facilities included in the project. Respondent and Wolverine Power Supply Cooperative also are co-owners, as tenants in common, of certain transmission facilities included in the project.

Operation, maintenance and other expenses are shared by Respondent and other owners according to contractual arrangements.

Expense accounts affected are steam-electric power generation operation and maintenance accounts, transmission operation and maintenance accounts, certain administrative and general operation accounts and general tax accounts.

(2) B.C. Cobb units 1-3 are name plate rated at 69 mw each. With 3 units running, the combined plant output is common header limited to 183 mw.

HYDROELECTRIC GENERATING PLANTS

1. Report on this page Hydro plants of 10,000 Kw (name plate rating) or more of installed capacity.
2. Report the information called for concerning generating plants and equipment at year end. Show associated prime movers and generators on the same line.
3. Exclude from this schedule, plant, the book cost of which is included in Account 121, *Nonutility Property*.
4. Designate any plant or portion thereof for which the responsibility is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating plant, other than a leased plant, or portion thereof, for which the respondent is not the sole owner but which respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars

Line No.	Name of Plant (a)	Location (b)	Name of Stream (c)	Water Wheels (In column (e), indicate whether horizontal or vertical. Also indicate type of runner - Francis (F), propeller (FP), automatically adjustable propeller (AP), impulse (I). Designate reversible type units by appropriate footnote)			
				Attended or Unattended (d)	Type of Unit (e)	Year Installed (f)	Gross Static Head With Pond Full (g)
1	Hardy	Newaygo County, Big Prairie Township	Muskegon	Attended*	Vert F	1931	99.5'
2					Vert F	1931	99.5'
3					Vert F	1931	99.5'
4							
5	Hodenpyl	Wexford County, Springville Township	Manistee	Attended*	Vert F	1925	67.5'
6					Vert F	1925	67.5'
7							
8	Tippy	Manistee County, Wellston	Manistee	Attended*	Vert F	1918	56.0'
9					Vert F	1918	56.0'
10					Vert F	1918	56.0'
11							
12							
13							
14							
15							
16							
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37							
38							
39							
40		* Part-time attendance					

HYDROELECTRIC GENERATING PLANTS (Continued)

(details) as to such matters as percent ownership by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.
5. Designate any plant or portion thereof leased to another company, and give name of lessee, date and term of lease and annual rent, and how determined. Specify whether lessee is an associated company.
6. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant or equipment was not operated within the past year, explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Water Wheels (Continued)			Generators						Total Installed Generating Capacity (Name Plate Ratings) (In megawatts) (q)	Line No.
Design Head (h)	RPM (i)	Maximum Hp. Capacity of Unit at Design Head (j)	Year Installed (k)	Voltage (l)	Phase (m)	Frequency or d.c. (n)	Nameplate Rating of Unit (In mega-watts) (o)	No. of Units in Plant (p)		
99'	163.6	14,800	1931	7.5	3	60	10	1		1
99'	163.6	14,800	1931	7.5	3	60	10	1		2
99'	163.6	14,800	1931	7.5	3	60	10	1	30	3
										4
62'	120	12,000	1925	7.5	3	60	9.0	1		5
62'	120	12,000	1925	7.5	3	60	9.0	1	18	6
										7
57.5'	109.1	10,000	1918	7.5	3	60	6.7	1		8
57.5'	109.1	10,000	1918	7.5	3	60	6.7	1		9
57.5'	109.1	10,000	1918	7.5	3	60	6.7	1	20	10
										11
										12
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PUMPED STORAGE GENERATING PLANTS

1. Include in this schedule pumped storage plants of 10,000 Kw (name-plate rating) or more of installed capacity.
2. Report the information called for concerning generating plants and equipment at year end. Shwo associated prime movers and generators on the same line.
3. Exclude from this schedule the book cost of plant included in Account 121, *Nonutility Property*.
4. Designate any plant or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any

Line No.	Name of Plant (a)	Location (b)	Name of Stream (c)	WATER WHEELS OF HYDRAULIC TURBINES/PUMPS (In column (e), indicate whether horizontal or vertical or inclined. Also indicate type of runner - Francis (F), fixed propeller (FP), automatically adjustable propeller (AP), impulse (I), or Tublar (T). Designate reversible type units by appropriate footnote)				
				Attended or Unattended (d)	Type of Unit (e)	Year Installed (f)	Gross Static Head With Pond Full (g)	Design Head (h)
1	Ludington (1)	Ludington	Lake Michigan	Attended	Vert F (2)	1973	363.7' (3)	353'
2					Vert F	1973	363.7'	353'
3					Vert F	1973	363.7'	353'
4					Vert F	1973	363.7'	353'
5					Vert F	1973	363.7'	353'
6					Vert F	1973	363.7'	353'
7								
8								

9
10
11
12 (1) Respondent and the Detroit Edison Company, a nonassociated company, are
13 co-owners, as tenants in common, of the Ludington Pumped Storage Plant
14 with Respondent having a 51% undivided interest and Detroit Edison a
15 49% undivided interest. A license for Project No 2680 has been issued
16 by the Federal Power Commission to the two companies as joint licensees.
17 The project includes the pumped storage plant, substation and certain
18 transmission facilities. Respondent is operator of the plant and is
19 responsible for operation and maintenance, except that operating agree-
20 ment specifies that mutual agreement be sought on major operation and
21 maintenance matters pertaining to the plant. Respondent and Detroit
22 Edison are entitled to 51% and 49%, respectively, of the generating
23 capability and energy output of the plant with pumping energy being
24 supplied in the same percentages.
25
26 Operation, maintenance and other expenses of the project are shared by
27 Respondent and Detroit Edison, 51% and 49%, respectively.
28
29 Expense accounts affected are hydraulic power generation operation and
30 maintenance accounts, transmission operation and maintenance accounts,
31 certain administrative and general operation accounts and general tax
32 accounts.
33
34 (2) All units are reversible pump/turbines.
35
36 (3) Change in Gross Static Head with pond full due to increase in average lake level for 2003.
37

PUMPED STORAGE GENERATING PLANTS (Continued)

generating plant, other than a leased plant, or portion thereof, for which the respondent shares in the operation of, furnish a concise statement explaining the arrangement and giving particulars as to such matters as percent ownership by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

SEPARATE MOTOR-DRIVEN PUMPS									Line No
RPM (Designate whether turbine or pump) (i)	Maximum Hp Capacity of Unit at Design Head (j)	Year Installed (k)	Type (l)	RPM (m)	Phase (n)	Frequency or d.c. (o)	NAME PLATE RATING IN Hp (p)	NAME PLATE RATING IN MVa (q)	
	None								1

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PUMPED STORAGE GENERATING PLANTS (Continued)

5. Designate any plant or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent and how determined. Specify whether lessee is an associated company.

6. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant or equipment was not operated within the past year, explain whether is has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Line No.	GENERATORS OR GENERATOR/MOTORS (In Column (v), designate whether generator or motor)						Total Installed Generating Capacity (Nameplate Ratings) (In megawatts)
	Year Installed	Voltage	Phase	Frequency or d.c.	Nameplate Rating of Unit (In megawatts) (Designate whether MVa, MW, or Hp; indicate power factor)	Number of Units in Plant	
	(r)	(s)	(t)	(u)	(v)	(w)	(x)
1	1973	20.0	3	60 Hz	Generator 329.8 MW 0.85 Power Factor	6	1,978.8
2							
3							
4							
5							
6							
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INTERNAL-COMBUSTION ENGINE AND GAS-TURBINE GENERATING PLANTS

1. Include on this page internal-combustion engine and gas-turbine plants of 10,000 kilowatts and more.
2. Report the information called for concerning plants and equipment at end of year. Show associated prime movers and generators on the same line.
3. Exclude from this page, plant, the book cost of which is included in Account 121, *Nonutility Property*.
4. Designate any plants or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating plant other than a leased plant, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the

Line No.	Name of Plant (a)	Location of Plant (b)	Prime Movers (In column (e), indicate basic cycle for gas-turbine as open or closed; indicate basic cycle for internal-combustion as 2 or 4)				
			Internal-Combustion or Gas-Turbine (c)	Year Installed (d)	Cycle (e)	Belted or Direct Connected (f)	Rated Hp of Unit (g)
1	Gaylord	Gaylord	Gas-Turbine	1966	Open	Direct Connected	-
2			Gas-Turbine	1968	Open	Direct Connected	-
3							
4	Campbell	West Olive	Gas-Turbine	1968	Open	Direct Connected	-
5							
6	Morrow	Comstock	Gas-Turbine	1968	Open	Direct Connected	-
7			Gas-Turbine	1969	Open	Direct Connected	-
8							
9	Weadock	Essexville	Gas-Turbine	1968	Open	Direct Connected	-
10							
11	Whiting	Near Erie	Gas-Turbine	1968	Open	Direct Connected	-
12							
13	Straits	Mackinaw City	Gas-Turbine	1969	Open	Direct Connected	-
14							
15	Thetford	North of Flint	Gas-Turbine	1970	Open	Direct Connected	-
16			Gas-Turbine	1971	Open	Direct Connected	-
17							
18							
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INTERNAL-COMBUSTION ENGINE AND GAS-TURBINE GENERATING PLANTS (Continued)

operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) as to such matters as percent of ownership by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenue are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.
5. Designate any plant or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent and how determined. Specify whether lessee is an associated company.
6. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant or equipment was not operated within the past year, explain whether it has been retired in the books of accounts or what disposition of the plant or equipment and its book cost are contemplated.

GENERATORS						Total Installed Generating Capacity (Nameplate Ratings) (In megawatts)	Line No.
Year Installed (h)	Voltage (i)	Phase (j)	Frequency or d.c. (k)	Nameplate Rating of Unit (In megawatts) (l)	No. of Units in Plant (m)	(n)	
1966	13.8	3	60	16.0	4		1
1968	13.8	3	60	18.6	1	82.6	2
							3
1968	13.8	3	60	18.6	1	18.6	4
							5
1968	13.8	3	60	18.0	1		6
1969	13.8	3	60	18.0	1	36.0	7
							8
1968	13.8	3	60	18.6	1	18.6	9
							10
1968	13.8	3	60	18.6	1	18.6	11
							12
1969	13.8	3	60	21.3	1	21.3	13
							14
1970	13.8	3	60	33.6	4	222.2	15
1971	13.8	3	60	17.6	5		16
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							21
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	ABBE - OSCODA CO	Distrib Unattended	138.00	24.90	
2	ABERDEEN - GRAND TWP	Distrib Unattended	46.00	12.47	
3	AGNEW - GRAND HAVEN TWP	Distrib Unattended	46.00	8.32	
4	ALAMO - ALAMO TWP	Distrib Unattended	46.00	24.90	
5	ALBER - BATTLE CREEK TWP	Distrib Unattended	46.00	8.32	
6	ALCONA DAM - CURTIS TWP	Distrib Unattended	138.00	4.80	
7			24.90	4.80	
8	ALDER CREEK - NEWTON TWP	Distrib Unattended	138.00	24.90	
9	ALDRICH - FLINT TWP	Distrib Unattended	46.00	8.32	
10	ALGER - MOFFITT TWP	Distrib Unattended	138.00	24.90	
11	ALGOMA - ALGOMA	Trans Unattended	138.00	46.00	7.60
12	ALMA - GREENDALE TWP	Trans Unattended	138.00	46.00	10.50
13	ALMEDA - FRASER	Trans Unattended	138.00	46.00	7.59
14	ALPINE - ALPINE TWP	Distrib Unattended	138.00	12.47	
15	ALTO - LOWELL TWP	Distrib Unattended	46.00	8.32	
16	AMBER - AMBER	Trans Unattended	138.00	46.00	10.50
17	AMPERSEE - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
18	APPLE - EGELSTON TWP	Distrib Unattended	46.00	12.47	
19			46.00	8.32	
20	APPLETON - BIG RAPIDS TWP	Distrib Unattended	46.00	12.47	
21	ASHMAN CIRCLE - MIDLAND TWP	Distrib Unattended	46.00	8.32	
22	ASYLUM - FLINT CITY	Distrib Unattended	46.00	13.80	
23	ATHERTON - BURTON TWP	Distrib Unattended	46.00	8.32	
24	ATLAS - ATLAS TWP	Distrib Unattended	46.00	8.32	
25	ATWATER - TEXAS TWP	Distrib Unattended	46.00	24.90	
26			46.00	8.32	
27	AUBURN - WILLIAMS TWP	Distrib Unattended	46.00	8.32	
28	AUSTIN - PORTAGE TWP	Distrib Unattended	46.00	8.32	
29	BACKUS - BACKUS TWP	Distrib Unattended	138.00	24.90	
30	BAGLEY - BAGLEY TWP	Distrib Unattended	138.00	24.90	
31	BALLENGER - FLINT TWP	Distrib Unattended	46.00	8.32	
32	BARD ROAD - BARD ROAD	Trans Unattended	138.00	46.00	7.50
33	BARNHARD - SAGINAW TWP	Distrib Unattended	46.00	8.32	
34	BARRY - HASTINGS	Trans Unattended	138.00	46.00	10.50
35			135.00	46.00	
36	BASS CREEK - ROBINSON	Trans Unattended	138.00	46.00	7.50
37	BATAVIA - BATAVIA	Trans Unattended	138.00	46.00	10.50
38	BATES - WHITE WATER TWP	Distrib Unattended	46.00	12.47	
39	BATTEESE - HENRIETTA TWP	Distrib Unattended	46.00	24.90	
40	BAUM STREET - SAGINAW TWP	Distrib Unattended	46.00	8.32	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
13	1					1
13	1					2
13	1					3
13	1					4
13	2					5
13	4					6
						7
10	1					8
13	1					9
13	1					10
30	1					11
38	1	1				12
30	1					13
13	1					14
13	1					15
100	2					16
10	1					17
16	2					18
						19
13	1					20
13	2					21
20	1					22
13	1					23
13	1					24
25	2					25
						26
10	1					27
13	1					28
10	1					29
25	2					30
23	2					31
30	1					32
25	2					33
88	2					34
						35
30	1					36
40	1					37
14	1					38
10	1					39
13	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BAVARIAN - FRANKENMUTH TWP	Distrib Unattended	46.00	8.32	
2	BAY ROAD - FRANKENLUST TWP	Distrib Unattended	138.00	24.90	
3	BEALS ROAD - WYOMING TWP	Trans Unattended	138.00	46.00	15.00
4			138.00	12.47	
5	BEAVER CREEK - BEAVER CREEK	Trans Unattended	138.00	46.00	
6	BECKER - EGELSTON TWP	Distrib Unattended	138.00	12.47	
7	BEECHER - MADISON TWP	Trans Unattended	138.00	46.00	15.00
8			46.00	12.47	
9			46.00	8.32	
10	BEERS - GENESSEE COUNTY	Distrib Unattended	46.00	8.32	
11	BEGOLE - PINE RIVER	Trans Unattended	138.00	46.00	10.50
12	BELDING - EUREKA TWP	Distrib Uattended	46.00	8.32	
13	BELL ROAD - TAYMOUTH TWP	Distrib Unattended	138.00	24.90	
14	BELLA VISTA - ROCKFORD	Distrib Unattended	46.00	8.32	
15	BELSAY - BURTON TWP	Distrib Unattended	46.00	8.32	
16	BENNETT - MERIDIAN TWP	Distrib Unattended	46.00	8.32	
17	BENNINGTON - BENNINGTON TWP	Distrib Unattended	138.00	24.90	
18	BEVERIDGE - FLINT TWP	Trans Unattended	138.00	46.00	15.00
19	BIG RAPIDS - BIG RAPIDS TWP	Distrib Unattended	46.00	7.56	
20	BIL MAR - OLIVE TWP	Distrib Unattended	138.00	8.32	
21	BINGHAM - BINGHAM	Trans Unattended	138.00	46.00	7.50
22	BISHOP - FLINT	Distrib Unattended	46.00	8.32	
23	BLACK RIVER - HOLLAND TWP	Trans Unattended	138.00	46.00	
24			138.00	12.47	
25	BLACKMAN - BLACKMAN TWP	Distrib Unattended	138.00	24.90	
26	BLACKSTONE STREET - BLACKMAN	Trans Unattended	138.00	46.00	10.00
27	BLINTON - GRNAD BLANC TWP	Distrib Unattended	138.00	24.90	
28	BLISSFIELD - BLISSFIELD TWP	Distrib Unattended	46.00	12.47	
29	BLUE WATER - BINGHAM TWP	Distrib Unattended	138.00	24.90	
30	BLUEGRASS - CHIPPEWA TWP	Distrib Unattended	138.00	8.32	
31	BOARDMAN - GARFIELD	Trans Unattended	138.00	46.00	7.60
32	BOMAN - FLUSHING TWP	Distrib Unattended	46.00	8.32	
33	BOON ROAD - HARING TWP	Distrib Unattended	46.00	8.32	
34	BOSTON SQUARE - PARIS TWP	Distrib Unattended	46.00	12.47	
35	BOWEN - PARIS TWP	Distrib Unattended	46.00	12.47	
36	BREEDSVILLE - COLUMBIA TWP	Distrib Unattended	46.00	24.90	
37	BRETON - PARIS TWP	Distrib Unattended	46.00	12.47	
38	BRICKER - OTISCO TWP	Distrib Unattended	138.00	24.90	
39	BRICKYARD - HOLTON TWP	Distrib Unattended	138.00	46.00	
40	BRIDGE STREET - JACKSON	Distrib Unattended	46.00	8.32	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
13	1					1
60	2					2
260	5					3
						4
30	1					5
13	1					6
185	4					7
						8
						9
13	1					10
38	1					11
13	1					12
13	1					13
13	1					14
13	1					15
12	1					16
13	1					17
200	2					18
13	1					19
20	1					20
40	1					21
14	1					22
80	3					23
						24
20	1					25
136	5	1				26
48	2					27
10	1					28
10	1					29
13	1					30
88	2					31
13	1					32
13	1					33
25	2					34
21	3					35
13	1					36
80	2					37
14	1					38
50	1					39
13	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BRIDGEPORT - BRIDGEPORT TWP	Distrib Unattended	46.00	8.32	
2	BRISTOL - SAGINAW TWP	Distrib Unattended	46.00	8.32	
3	BROADMOOR - PARIS TWP	Distrib Unattended	138.00	46.00	15.00
4			138.00	13.80	
5	BROADWAY - FRIUTPORT TWP	Distrib Unattended	46.00	12.47	
6	BROUGHWELL - RIVES TWP	Distrib Unattended	138.00	24.90	
7	BUCK CREEK - BUCK CREEK	Trans Unattended	138.00	46.00	15.20
8	BULLOCK - MIDLAND TWP	Trans Unattended	138.00	46.00	10.50
9			46.00	8.32	
10	BURLINGAME - WYOMING TWP	Distrib Unattended	46.00	12.47	
11	BURROWS - SAGINAW TWP	Distrib Unattended	46.00	8.32	
12	BURTCH ROAD - GRASS LAKE TWP	Distrib Unattended	46.00	24.90	
13	BYRON CENTER - BYRON TWP	Distrib Unattended	46.00	12.47	
14			46.00	8.32	
15	CADILLAC - CLAM LAKE TWP	Distrib Unattended	46.00	24.90	
16			46.00	8.32	
17	CADMUS - MADISON TWP	Distrib Unattended	46.00	12.47	
18	CALHOUN - CALHOUN	Trans Unattended	138.00	46.00	7.59
19	CALKINS - FLINT TWP	Distrib Unattended	46.00	8.32	
20	CALVIN - PARIS TWP	Distrib Unattended	46.00	12.47	
21	CAMELOT LAKE - UNION TWP	Distrib Unattended	138.00	24.90	
22	CANNON - CANNON	Trans Unattended	138.00	46.00	10.50
23	CARROLL - BLACKMAN TWP	Distrib Unattended	46.00	8.32	
24	CARROLLTON - BUENA VISTA TWP	Distirb Unattended	23.00	8.32	
25	CARY ROAD - COLUMBIA TWP	Distrib Unattended	46.00	24.90	
26	CASCADE - CASCADE TWP	Distrib Unattended	46.00	8.32	
27	CASINO - MT PLEASANT	Distrib Unattended	46.00	8.32	
28	CASS ROAD - GARFIELD TWP	Distrib Unattended	46.00	12.47	
29	CEDAR SPRINGS - SOLON TWP	Distrib Unattended	138.00	24.90	
30	CEMENT CITY - COLUMBIA TWP	Distrib Unattended	138.00	46.00	10.50
31	CENTER ROAD - BURTON TWP	Distrib Unattended	46.00	8.32	
32	CENTREVILLE - NOTTAWA TWP	Distrib Unattended	46.00	24.90	
33	CHAFFEE - GRAND RAPIDS TWP	Distrib Unattended	46.00	12.47	
34	CHARLOTTE - EATON TWP	Distrib Unattended	46.00	8.32	
35	CHASE - CHASE	Trans Unattended	138.00	46.00	
36	CHAUNCEY - SHERIDAN TWP	Distrib Unattended	46.00	8.32	
37	CHEBOYGAN - BENTON TWP	Distrib Unattended	46.00	12.47	
38	CHESANING - CHESANING TWP	Distrib Unattended	46.00	8.32	
39	CHEYENNE - SAGINAW TWP	Distrib Unattended	46.00	8.32	
40	CHICAGO - GEORGETOWN TWP	Distrib Unattended	138.00	12.47	

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Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
13	1					1
13	1					2
225	3					3
						4
25	2					5
10	1					6
100	1					7
83	3					8
						9
26	3					10
19	2					11
10	1					12
25	2					13
						14
19	3					15
						16
13	1					17
30	1					18
25	2					19
40	2					20
13	1					21
30	1					22
13	1					23
13	3					24
14	1					25
27	2					26
13	1					27
20	1					28
20	1					29
40	1					30
10	1					31
13	1					32
20	1					33
14	2					34
18	3					35
13	1					36
15	2					37
13	1					38
25	2					39
12	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	CLARE - GRANT TWP	Distrib Unattended	138.00	24.90	
2	CLAREMONT - BRIDGEPORT	Trans Unattended	138.00	46.00	15.00
3	CLAY - GRAND RAPIDS TWP	Distrib Unattended	46.00	7.55	
4	CLEARWATER - CLEARWATER	Trans Unattended	138.00	46.00	
5	CLEVELAND - SPRING LAKE	Trans Unattended	138.00	46.00	15.20
6	CLIO - VIENNA TWP	Distrib Unattended	46.00	8.32	
7	CLUB - DALTON TWP	Distrib Unattended	138.00	12.47	
8	CLYDE ROAD - IONIA TWP	Distrib Unattended	46.00	24.90	
9	COBB B C PLANT - MUSKEGON	Trans Attended	138.00	17.50	
10			138.00	46.00	4.50
11	COCHRAN - EATON TWP	Distrib Unattended	138.00	24.90	
12	COLE CREEK - FLUSHING	Trans Unattended	138.00	46.00	7.60
13	COLEMAN - WARREN TWP	Distrib Unattended	46.00	8.32	
14	COLLEGE PARK - MADISON TWP	Distrib Unattended	46.00	12.47	
15	COLONY FARM - KALAMAZOO	Distrib Unattended	138.00	24.90	
16	COMSTOCK - COMSTOCK TWP	Distrib Unattended	46.00	8.32	
17	CONVIS - CONVIS TWP	Distrib Unattended	138.00	24.90	
18	CONWAY - LITTLE TRAVER TWP	Distrib Unattended	46.00	13.80	
19	COOKE DAM - OSCODA TWP	Distirb Unattended	46.00	2.40	
20			5.00	2.40	
21	COOLEY - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
22	COOPERSVILLE - POLKTON TWP	Distrib Unattended	46.00	8.32	
23	CORNELL - CALEDONIA	Trans Unattended	138.00	46.00	
24	CORUNNA - CALEDONIA TWP	Distrib Unattended	46.00	8.32	
25	COTTAGE GROVE - KAWKAWLIN TWP	Distrib Unattended	138.00	24.90	
26	COURT - BURTON TWP	Distrib Unattended	46.00	8.32	
27	COWAN LAKE - CANNON TWP	Distrib Unattended	138.00	24.90	
28	CRAWFORD - UNION TWP	Distrib Unattended	46.00	8.32	
29	CROTON - CROTON TWP	Trans Unattended	138.00	46.00	10.50
30	CURTIS - WARREN TWP	Distrib Unattended	46.00	8.32	
31	CUTLERVILLE - BYRON TWP	Distrib Unattended	46.00	12.47	
32	DAVENPORT - SAGINAW TWP	Distrib Unattended	46.00	8.32	
33	DAVISON - DAVISON TWP	Distrib Unattended	46.00	8.32	
34	DEAN ROAD - TYRONE TWP	Distrib Unattended	138.00	24.90	
35	DEJA - DAY	Trans Unattended	140.00	22.00	10.00
36	DELANEY - BURTON	Trans Unattended	138.00	46.00	15.20
37	DELHI - LANSING	Trans Unattended	138.00	46.00	10.00
38	DEWEY - WALKER TWP	Distrib Unattended	46.00	12.47	
39	DEWITT - DEWITT TWP	Distrib Unattended	46.00	8.32	
40	DIMONDALE - WINDSOR TWP	Distrib Unattended	46.00	8.32	

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Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
14	1					1
200	2					2
20	1					3
30	1					4
60	1					5
19	2					6
12	1					7
13	1					8
170	1					9
200	2					10
13	1					11
30	1					12
13	1					13
20	1					14
13	1					15
14	2					16
13	1					17
13	1					18
13	4					19
						20
22	3					21
13	1					22
100	1					23
13	1					24
10	1					25
20	1					26
13	1					27
13	1					28
30	1					29
13	1					30
23	2					31
13	1					32
25	2					33
30	1					34
40	1					35
100	1					36
80	2					37
40	2					38
25	2					39
10	1					40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	DIXIE - MT MORRIS TWP	Distrib Unattended	46.00	8.32	
2	DOEHLER JARVIS - PARIS TWP	Distrib Unattended	46.00	12.47	
3	DORR CORNERS - DORR TWP	Distrib Unattended	138.00	8.32	
4	DORT - GENESEE	Trans Unattended	140.00	46.00	21.00
5			138.00	46.00	
6	DOWLING - HUDSON	Trans Unattended	138.00	46.00	
7	DRAKE ROAD - OSHTEMO TWP	Distrib Unattended	138.00	8.32	
8	DUFFIELD - CLAYTON TWP	Distrib Unattended	138.00	24.90	
9	DURAND - VERNON TWP	Distrib Unattended	46.00	8.32	
10	DUTTON - GAINES TWP	Distrib Unattended	138.00	12.47	
11	EAST BAY - EAST BAY TWP	Distrib Unattended	46.00	12.47	
12	EAST GENESEE AVENUE - BUENA VISTA TWP	Distrib Unattended	46.00	8.32	
13	EAST JORDAN - SOUTH ARM TWP	Distrib Unattended	46.00	12.47	
14	EAST MUSKEGON - MUSKEGON TWP	Distrib Unattended	46.00	12.47	
15	EAST TAWAS - BALDWIN TWP	Distrib Unattended	138.00	24.90	
16	EASTON - EASTON TWP	Distrib Unattended	138.00	24.90	
17	EASTWOOD - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
18	EDENVILLE DAM - EDENVILLE	Distrib Unattended	138.00	46.00	5.20
19			46.00	2.50	
20	ELLSWORTH - WALKER TWP	Distrib Unattended	46.00	12.47	
21	ELM STREET - EMMET TWP	Distrib Unattended	138.00	46.00	10.50
22			138.00	8.32	
23			46.00	8.32	
24	ELMWOOD - ELMWOOD	Trans Unattended	138.00	46.00	7.50
25	EMERALD - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
26	EMMET - BEAR CREEK	Trans Unattended	138.00	46.00	7.50
27	ENGLISHVILLE - ALGOMA TWP	Distrib Unattended	138.00	24.90	
28	ESSEXVILLE - BANGOR TWP	Distrib Unattended	46.00	8.32	
29	EUREKA - EUREKA	Trans Unattended	138.00	46.00	
30	EVANSTON - EGELSTON TWP	Distrib Unattended	46.00	12.47	
31	FAIRBANKS - WALKER TWP	Distrib Unattended	46.00	12.47	
32	FARR ROAD - MAINSTEE	Trans Unattended	138.00	46.00	
33	FELCH ROAD - GARFIELD	Trans Unattended	138.00	46.00	10.50
34	FENNVILLE - CLYDE TWP	Distrib Unattended	46.00	8.32	
35	FENTON - FENTON TWP	Distrib Unattended	46.00	8.32	
36	FERGUSON - SUMMIT TWP	Distrib Unattended	46.00	8.32	
37	FILLMORE - BLENDON TWP	Distrib Unattended	138.00	12.47	
38	FLUSHING - FLUSHING TWP	Distrib Unattended	46.00	8.32	
39	FOOTE HYDRO - OSCODA TWP	Distrib Unattended	46.00	4.80	
40			5.00	4.80	

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
13	1					1
25	2					2
13	1					3
200	2					4
						5
30	1					6
40	2					7
13	1					8
10	1					9
32	2					10
13	1					11
13	2					12
13	1					13
13	1					14
13	1					15
20	1					16
13	1					17
21	4					18
						19
60	3					20
98	3					21
						22
						23
30	1					24
13	1					25
30	1					26
13	1					27
10	1					28
30	1					29
25	2					30
40	2					31
30	1					32
38	1					33
13	1					34
14	1					35
13	1					36
10	1					37
13	1					38
11	5					39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1			5.00	2.40	
2	FORDYCE - UNION TWP	Distrib Unattended	46.00	8.32	
3	FORT CUSTER - BEDFORD TWP	Distrib Unattended	138.00	24.90	
4	FOUNTAIN - BATTLE CREEK TWP	Distrib Unattended	46.00	13.80	
5			46.00	8.32	
6			46.00	4.36	
7	FOUR MILE - WALKER TWP	Trans Unattended	138.00	46.00	15.00
8			138.00	12.47	15.00
9	FOURTEENTH STREET - BURTON TWP	Distrib Unattended	46.00	8.32	
10	FRANCIS ROAD - FLUSHING TWP	Distrib Unattended	46.00	8.32	
11	FRANKENMUTH - FRANKENMUTH TWP	Distrib Unattended	46.00	8.32	
12	FREELAND - TITTABAWASSEE TWP	Distrib Unattended	46.00	8.32	
13	FREMONT - SHERIDAN TWP	Distrib Unattended	46.00	8.32	
14	FULTON - ADA TWP	Distrib Unattended	46.00	12.47	
15	GALESBURG - CHARLESTON TWP	Distrib Unattended	46.00	8.32	
16	GAYLORD GEN STATION - LIVINGSTON	Trans Unattended	138.00	46.00	5.25
17	GENESEEVILLE - GENESEE TWP	Distrib Unattended	46.00	8.32	
18	GETTY - MUSKEGON TWP	Distrib Unattended	46.00	12.47	
19	GILKEY CREEK - DAVISON TWP	Distrib Unattended	46.00	8.32	
20	GILSON - RICHLAND TWP	Distrib Unattended	46.00	24.90	
21	GLADWIN - GROUT TWP	Distrib Unattended	46.00	8.32	
22	GLEANER - TITTABAWASSEE	Trans Unattended	138.00	46.00	7.60
23	GLEN LAKE - GLEN ARBOR TWP	Distrib Unattended	46.00	12.47	
24	GLENDALE - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
25	GOGUAC - BATTLE CREEK TWP	Distrib Unattended	46.00	8.32	
26	GOLDEN - MIDLAND TWP	Distrib Unattended	46.00	8.32	
27	GOODALE - BEDFORD TWP	Distrib Unattended	46.00	8.32	
28	GRAND BLANC - GRAND BLANC TWP	Distrib Unattended	46.00	8.32	
29	GRAND LEDGE - ONEIDA TWP	Distrib Unattended	46.00	8.32	
30	GRAND RIVER - MERIDIAN TWP	Distrib Unattended	46.00	8.32	
31	GRAND VALLEY - TALLMADGE TWP	Distrib Unattended	46.00	12.47	
32	GRANDVILLE - WYOMING TWP	Distrib Unattended	46.00	12.47	
33	GRAYLING - GRAYLING TWP	Distrib Unattended	46.00	8.32	
34	GREENSPIRE - PORTAGE TWP	Distrib Unattended	46.00	8.32	
35	GREENVILLE - EUREKA TWP	Distrib Unattended	46.00	8.32	
36	GREENWOOD - HORTON TWP	Distrib Unattended	138.00	24.90	
37	GRODI ROAD - ERIE TWP	Distrib Unattended	138.00	46.00	
38	GROUT - GROUT	Trans Unattended	138.00	46.00	
39	GROVER - ARCADIA TWP	Distrib Unattended	46.00	8.32	
40	HACKETT - TITTABAWASSEE TWP	Distrib Unattended	138.00	8.32	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
13	1					2
60	2					3
35	3					4
						5
						6
240	4					7
						8
25	2					9
10	1					10
13	1					11
10	1					12
27	3					13
23	2					14
10	1					15
15	1					16
13	1					17
10	1					18
13	1					19
10	1					20
13	2					21
50	1					22
12	2					23
13	1					24
13	1					25
13	1					26
13	1					27
19	2					28
20	1					29
23	2					30
13	1					31
25	2					32
12	2					33
13	1					34
13	1					35
13	1					36
30	1					37
30	1					38
13	1					39
13	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HAGADORN - MERIDIAN TWP	Distrib Unattended	138.00	8.32	
2	HAGER PARK - GEORGETOWN TWP	Distrib Unattended	138.00	12.47	
3	HALSEY - HOLLY TWP	Trans Unattended	138.00	46.00	
4	HAMILTON - HEATH TWP	Distrib Unattended	46.00	8.32	
5	HAMMOND RD - GARFIELD TWP	Distrib Unattended	46.00	12.47	
6	HANSEN - WYOMING TWP	Distrib Unattended	46.00	12.47	
7	HARDY DAM - HARDY DAM	Trans Unattended	138.00	7.50	
8	HARING - BOON TWP	Distrib Unattended	138.00	8.32	
9	HARLEM - OLIVE TWP	Distrib Unattended	46.00	8.32	
10	HARPER ROAD - DELHI TWP	Distrib Unattended	46.00	24.90	
11	HARRISON - HAYES TWP	Distrib Unattended	46.00	8.32	
12	HARVEY STREET - GRAND RAPIDS TWP	Distrib Unattended	46.00	12.47	
13	HASKELITE - WALKER TWP	Distrib Unattended	46.00	12.47	
14	HASTINGS - HASTINGS TWP	Distrib Unattended	46.00	8.32	
15	HAYES STREET - GRAND HAVEN TWP	Distrib Unattended	46.00	8.32	
16	HAZELWOOD - GUN PLAIN	Trans Unattended	138.00	46.00	15.20
17	HEMLOCK - RICHLAND TWP	Distrib Unattended	46.00	8.32	
18	HEMPHILL - BURTON TWP	Trans Unattended	140.00	46.00	
19	HENDERSHOT - MACON TWP	Distrib Unattended	138.00	12.47	
20	HICKORY - SPRING LAKE TWP	Distrib Unattended	46.00	12.47	
21	HIGGINS - HIGGINS	Trans Unattended	138.00	46.00	
22	HODENPYL DAM - SPRINGVILLE TWP	Distrib Unattended	138.00	46.00	10.50
23	HOGAN - ARGENTINE TWP	Distrib Unattended	46.00	8.32	
24	HOGSBACK - DELHI TWP	Distrib Unattended	46.00	8.32	
25	HOLTON - HOLTON TWP	Distrib Unattended	46.00	24.90	
26	HOMESTEAD - JOYFIELD TWP	Distrib Unattended	46.00	12.47	
27	HOSPITAL - GARFIELD TWP	Distrib Unattended	46.00	12.47	
28	HOTCHKISS - MONITOR TWP	Distrib Unattended	138.00	24.90	
29	HOUGHTON HEIGHTS - ROSCOMMON	Distrib Unattended	46.00	24.90	
30	HUDSON - HUDSON TWP	Distrib Unattended	46.00	8.32	
31	HUDSONVILLE - GEORGETOWN TWP	Distrib Unattended	138.00	12.47	
32	HUGHES ROAD - MARSHALL	Trans Unattended	138.00	46.00	
33	HULL STREET - ALGOMA TWP	Distrib Unattended	138.00	24.90	
34	HUNT ROAD - ADRIAN TWP	Distrib Unattended	46.00	12.47	
35	HURON - MONITOR TWP	Distrib Unattended	46.00	8.32	
36	HYDE PARK - DALTON TWP	Distrib Unattended	46.00	12.47	
37	INGHAM - BLACKMAN TWP	Distrib Unattended	46.00	8.32	
38	IOSCO - OSCODA	Trans Unattended	140.00	46.00	
39			138.00	46.00	
40	IRISH ROAD - DAVISON TWP	Distrib Unattended	46.00	24.90	

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SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
16	1					1
20	1					2
60	2					3
13	1					4
13	1					5
13	1					6
40	1					7
20	1					8
12	2					9
13	1					10
13	2					11
50	4					12
25	2					13
20	2					14
13	1					15
200	2					16
10	1					17
160	2					18
10	1					19
13	1					20
41	4					21
30	1					22
13	1					23
25	2					24
13	1					25
13	1					26
13	1					27
13	1					28
13	1					29
10	1					30
20	1					31
50	1					32
13	1					33
13	1					34
10	1					35
13	1					36
19	2					37
60	2					38
						39
13	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	IRON STREET - BURTON TWP	Distrib Unattended	46.00	8.32	
2	ISABELLA - UNION TWP	Distrib Unattended	46.00	8.32	
3	ISLAND ROAD - EATON	Trans Unattended	138.00	46.00	10.50
4	ITHACA - NEWARK TWP	Distrib Unattended	46.00	8.32	
5	IVANREST - WYOMING TWP	Distrib Unattended	46.00	12.47	
6	JACKMAN - BEDFORD TWP	Distrib Unattended	46.00	12.47	
7	JAMES SAVAGE - MIDLAND	Distrib Unattended	46.00	8.32	
8	JAMESTOWN - JAMESTOWN TWP	Distrib Unattended	138.00	12.47	
9	JANES - BUENA VISTA TWP	Distrib Unattended	46.00	8.32	
10	JEFFS ROAD - WHITEFORD TWP	Distrib Unattended	46.00	12.47	
11	JUDD ROAD - BURTON TWP	Distrib Unattended	46.00	8.32	
12	KALARAMA - PORTAGE TWP	Distrib Unattended	46.00	8.32	
13	KALKASKA - KALKASKA TWP	Distrib Unattended	46.00	12.47	
14	KEARSLEY - GENESEE TWP	Distrib Unattended	46.00	8.32	
15	KEATING - MUSKEGON TWP	Distrib Unattended	46.00	12.47	
16	KELLOGGSVILLE - WYOMING TWP	Distrib Unattended	46.00	12.47	
17	KENDALL - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
18	KENDRICK - CASCADE TWP	Distrib Unattended	138.00	12.47	
19	KENT AIRPORT - CASCADE TWP	Distrib Unattended	46.00	12.47	
20	KIESEL - BANGOR TWP	Distrib Unattended	46.00	8.32	
21	KILGORE - PORTAGE TWP	Distrib Unattended	46.00	8.32	
22	KINDERHOOK - OVID TWP	Distrib Unattended	46.00	8.32	
23	KINNEY - WALKER TWP	Distrib Unattended	46.00	12.47	
24	KIPP ROAD - VEVAY TWP	Distrib Unattended	138.00	24.90	
25	KNAPP - GRAND RAPIDS	Distrib Unattended	46.00	12.47	
26	KNIGHT - HAMPTON TWP	Distrib Unattended	46.00	8.32	
27	KOCHVILLE - FRANKENLUST TWP	Distrib Unattended	46.00	8.32	
28	KOLASSA - BRONSON TWP	Distrib Unattended	46.00	24.90	
29	KRAFT AVENUE - CASCADE	Distrib Unattended	138.00	12.47	
30	LABARGE - CALEDONIA TWP	Distrib Unattended	46.00	8.32	
31	LAFAYETTE - LAFAYETTE	Trans Unattended	138.00	46.00	15.20
32	LAGRAVE - GRAND RAPIDS TWP	Distrib Unattended	46.00	12.47	
33	LAINSBURG - SCIOTA TWP	Distrib Unattended	46.00	8.32	
34	LAKE CITY - REEDER TWP	Distrib Unattended	46.00	24.90	
35	LAKE LANSING - INGHAM COUNTY	Distrib Unattended	46.00	8.32	
36	LAMBERTVILLE - BEDFORD TWP	Distrib Unattended	46.00	12.47	
37	LAMOREAUX - ALPINE TWP	Distrib Unattended	46.00	12.47	
38	LANDWER - FERRYSBURG	Distrib Unattended	46.00	12.47	
39	LARKIN - MIDLAND TWP	Distrib Unattended	46.00	8.32	
40	LASALLE - LASALLE TWP	Distrib Unattended	46.00	12.47	

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SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
23	2					1
25	2					2
60	2					3
13	1					4
25	2					5
25	2					6
12	1					7
20	1					8
13	1					9
13	1					10
25	2					11
13	1					12
10	1					13
15	2					14
25	2					15
25	2					16
13	1					17
40	2					18
25	2					19
13	1					20
20	1					21
10	1					22
10	1					23
30	1					24
20	1					25
13	1					26
13	1					27
10	1					28
100	2					29
14	1					30
80	1					31
40	2					32
10	1					33
14	1					34
13	1					35
13	1					36
13	1					37
13	1					38
25	2					39
13	1					40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	LAWNDALE - SAGINAW	Trans Unattended	138.00	46.00	21.00
2	LAYTON - MAPLE GROVE	Trans Unattended	138.00	46.00	
3	LEE STREET - WYOMING TWP	Distrib Unattended	46.00	12.47	
4	LEFFINGWELL - GRAND APIDS TWP	Distrib Unattended	46.00	12.47	
5	LEITH STREET - BURTON TWP	Distrib Unattended	46.00	8.32	
6	LENNON ROAD - FLINT TWP	Distrib Unattended	46.00	8.32	
7	LETTS ROAD - LARKIN TWP	Distrib Unattended	138.00	24.90	
8	LEVEL PARK - BEDFORD TWP	Distrib Unattended	46.00	8.32	
9	LEVELY - EDENVILLE TWP	Distrib Unattended	46.00	24.90	
10	LIBERTY - BATTLE CREEK TWP	Distrib Unattended	46.00	8.32	
11	LINDBERGH - OSHTEMO	Trans Unattended	138.00	46.00	15.20
12	LINDEN - FENTON TWP	Distrib Unattended	46.00	8.32	
13	LITCHFIELD - LITCHFIELD TWP	Distrib Unattended	46.00	8.32	
14	LOMBARD - SHERIDAN TWP	Distrib Unattended	46.00	8.32	
15	LONG LAKE - FENTON TWP	Distrib Unattended	46.00	8.32	
16	LOOKING GLASS - WATERTOWN	Trans Unattended	138.00	46.00	
17	LOVEJOY - BURNS TWP	Distrib Unattended	138.00	24.90	
18	LOVELL - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
19	MACATAWA - HOLLAND TWP	Distrib Unattended	46.00	8.32	
20	MACKINAW CITY - MACKINAW TWP	Distrib Unattended	46.00	24.90	
21	MANCHESTER - MANCHESTER TWP	Distrib Unattended	46.00	8.32	
22	MANISTEE - FILER TWP	Distrib Unattended	46.00	12.47	
23	MANLIUS - MANLIUS	Distrib Unattended	138.00	46.00	10.50
24	MAPLE GROVE - FRIUTPORT TWP	Distrib Unattended	46.00	12.47	
25	MARKEY - MARKEY TWP	Distrib Unattended	46.00	8.32	
26	MARQUETTE - EASTON	Trans Unattended	138.00	46.00	7.00
27	MASON - VEVAY TWP	Distrib Unattended	46.00	8.32	
28	MAUMEE - ADRIAN TWP	Distrib Unattended	46.00	12.47	
29	MAYFAIR - MT MORRIS TWP	Distrib Unattended	46.00	8.32	
30	MCBAIN - RICHLAND TWP	Distrib Unattended	46.00	24.90	
31	MCCRACKEN - NORTON TWP	Distrib Unattended	46.00	12.47	
32	MCGULPIN - MACKINAW CITY	Trans Unattended	138.00	46.00	5.25
33	MEADOWBROOKE - CALEDONIA TWP	Distrib Unattended	138.00	12.47	
34	MECOSTA - GREEN	Trans Unattended	138.00	46.00	
35	MENDON - NOTTAWA TWP	Distrib Unattended	46.00	24.90	
36			46.00	8.32	
37	MICHIGAN - CITY OF GRAND RAPIDS	Distrib Unattended	138.00	12.47	
38	MICHIGAN CENTER - SUMMIT TWP	Distrib Unattended	46.00	8.32	
39	MICOR - SUMMIT TWP	Distrib Unattended	46.00	8.32	
40	MIDDLEVILLE - THORNAPPLE TWP	Distrib Unattended	46.00	8.32	

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
160	2					1
30	1					2
25	2					3
25	2					4
22	3					5
33	3					6
23	2					7
12	1					8
13	1					9
16	2					10
100	1					11
13	1					12
13	1					13
14	1					14
14	1					15
60	1					16
10	1					17
28	4					18
13	2					19
13	1					20
13	1					21
20	1					22
38	1					23
25	2					24
10	1					25
40	2					26
13	1					27
13	1					28
30	3					29
11	2					30
24	3					31
30	2					32
32	2					33
60	2					34
23	3					35
						36
20	1					37
13	1					38
13	1					39
13	1					40

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	MIDLAND - MIDLAND TWP	Distrib Unattended	46.00	8.32	
2	MIDWAY - GUN PLAIN TWP	Distrib Unattended	46.00	8.32	
3	MILES ROAD - SOUTH ARM	Trans Unattended	138.00	46.00	7.60
4	MILHAM - PORTAGE	Trans Unattended	138.00	46.00	15.00
5	MILL GROVE - ALLEGAN TWP	Distrib Unattended	46.00	24.90	
6	MILLER ROAD - FLINT TWP	Distrib Unattended	46.00	8.32	
7	MILLERS POINT - KALAMAZOO TWP	Distrib Unattended	138.00	8.32	
8	MILTON - BIG RAPIDS TWP	Distrib Unattended	46.00	12.47	
9	MIO DAM - BIG CREEK TWP	Trans Unattended	138.00	2.50	
10			2.50	12.00	
11			2.50	4.80	
12	MOLINE - DORR TWP	Distrib Unattended	46.00	8.32	
13	MONA LAKE - FRUITPORT TWP	Distrib Unattended	46.00	12.47	
14	MONITOR - MONITOR	Trans Unattended	138.00	46.00	
15	MONTROSE - MONTROSE TWP	Distrib Unattended	46.00	8.32	
16	MOORE ROAD - FAYETTE	Trans Unattended	138.00	46.00	
17	MORGAN - PENNFIELD TWP	Distrib Unattended	46.00	8.32	
18	MORLEY - BUENA VISTA TWP	Distrib Unattended	46.00	8.32	
19	MORRELL - SUMMIT	Distrib Unattended	46.00	8.32	
20	MORROW - MORROW	Trans Unattended	138.00	46.00	7.59
21	MT MORRIS - MT MORRIS TWP	Distrib Unattended	46.00	8.32	
22	MT PLEASANT - UNION TWP	Distrib Unattended	46.00	8.32	
23	MULLINS - WALKER TWP	Distrib Unattended	138.00	12.47	
24	MUSKEGON HEIGHTS - MUSKEGON TWP	Distrib Unattended	138.00	46.00	21.00
25			138.00	12.47	
26	NEFF ROAD - THETFORD TWP	Distrib Unattended	138.00	24.90	
27	NEWBURG - VERNON TWP	Distrib Unattended	46.00	24.90	
28	NIAGARA - SAGINAW TWP	Distrib Unattended	46.00	8.32	
29	NINETEEN - GREEN TWP	Distrib Unattended	138.00	12.47	
30	NORTH BELDING - OTISCO	Trans Unattended	138.00	46.00	7.60
31	NORTH CORUNNA - CALEDONIA TWP	Distrib Unattended	138.00	8.32	
32	NORTH KENT - PLAINFIELD TWP	Distrib Unattended	46.00	12.47	
33	NORTH LANSING - DEWITT TWP	Distrib Unattended	46.00	8.32	
34	NORTH MUSKEGON - MUSKEGON TWP	Distrib Unattended	46.00	12.47	
35	NORTH PARK - GRAND RAPIDS TWP	Distrib Unattended	46.00	12.47	
36	NORTHERN FIBRE - OLIVE TWP	Distrib Unattended	138.00	8.32	
37	NORTON - FRUITPORT TWP	Distrib Unattended	46.00	12.47	
38	OAK STREET - BLACKMAN TWP	Distrib Unattended	46.00	8.32	
39	OAKLAND - HOLLY TWP	Trans Unattended	138.00	46.00	7.50
40	OAKWOOD - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
13	1					1
13	1					2
30	1					3
60	1					4
10	1					5
13	1					6
40	2					7
14	1					8
18	5					9
						10
						11
13	1					12
14	1					13
68	2					14
11	2					15
160	2					16
13	1					17
10	1					18
13	1					19
130	3					20
13	1					21
13	1					22
20	1					23
160	3					24
						25
13	1					26
11	1					27
13	1					28
13	1					29
30	1					30
13	1					31
31	3					32
10	1					33
20	1					34
20	1					35
13	1					36
10	1					37
18	2					38
30	1					39
13	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	OBERLIN - SAGE TWP	Distrib Unattended	46.00	24.90	
2	OGEMAW - WEST BRANCH	Trans Unattended	138.00	46.00	5.25
3	OHMAN ROAD - EVART TWP	Distrib Unattended	138.00	24.90	
4	OLIVER - OWOSSO TWP	Distrib Unattended	46.00	8.32	
5	ORCHARD ROAD - MIDLAND TWP	Distrib Unattended	46.00	8.32	
6	ORIOLE - PERE MARQUETTE TWP	Distrib Unattended	46.00	24.90	
7	OTISVILLE - FOREST TWP	Distrib Unattended	46.00	8.32	
8	OTTAWA BEACH - PARK TWP	Distrib Unattended	46.00	8.32	
9	OVID - OVID TWP	Distrib Unattended	6.00	8.32	
10	OWOSSO - CALEDONIA TWP	Distrib Unattended	138.00	46.00	15.20
11			46.00	8.32	
12	PAGE AVENUE - LEONI	Trans Unattended	140.00	46.00	15.00
13	PALMER - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
14	PARKWAY - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
15	PARNALL - BLACKMAN TWP	Distrib Unattended	46.00	8.32	
16	PARR ROAD - MANCHESTER	Trans Unattended	138.00	46.00	10.50
17	PASADENA - FLINT TWP	Distrib Unattended	138.00	46.00	4.80
18			46.00	8.32	
19	PATTERSON - BANGOR TWP	Distrib Unattended	46.00	8.32	
20	PAVILION - PAVILION TWP	Distrib Unattended	138.00	8.32	
21	PEACOCK - BATH TWP	Distrib Unattended	46.00	8.32	
22	PECK ROAD - MONTCALM TWP	Distrib Unattended	46.00	24.90	
23	PERRY - PERRY TWP	Distrib Unattended	46.00	8.32	
24	PETTIS ROAD - ADA TWP	Distrib Unattended	138.00	24.90	
25	PHILLIPS - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
26	PIGEON LAKE - PORT SHELDON TWP	Distrib Unattended	46.00	8.32	
27	PINE RIVER - ARCADA TWP	Distrib Unattended	46.00	8.32	
28	PISTON RING - SPARTA TWP	Distrib Unattended	138.00	12.47	
29			46.00	8.32	
30	PITCHER - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
31	PLAINFIELD - PLAINFIELD TWP	Distrib Unattended	46.00	8.32	
32	PLAINWELL - GUN PLAIN TWP	Distrib Unattended	46.00	8.32	
33	PORT CALCITE - ROGERS TWP	Distrib Unattended	138.00	13.80	
34	PORT SHELDON - PORT SHELDON	Trans Unattended	138.00	46.00	7.50
35	PORTAGE - PORTAGE TWP	Distrib Unattended	46.00	8.32	
36	PORTER - GRAND BLANC TWP	Distrib Unattended	138.00	8.32	
37	PORTSMOUTH - BLUMFIELD TWP	Distrib Unattended	138.00	24.90	
38	POTTER - SAGINAW TWP	Distrib Unattended	46.00	8.32	
39	POTTERVILLE - BENTON TWP	Distrib Unattended	46.00	8.32	
40	QUINCY - QUINCY TWP	Distrib Unattended	46.00	8.32	

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SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
10	1					1
15	1					2
13	1					3
13	1					4
20	2					5
25	2					6
13	1					7
13	1					8
13	1					9
125	3					10
						11
60	1					12
25	2					13
25	2					14
20	2					15
40	1					16
113	3					17
						18
13	1					19
20	1					20
14	1					21
13	1					22
13	1					23
13	1					24
25	2					25
13	1					26
13	1					27
30	2					28
						29
11	2					30
13	1					31
13	1					32
20	2					33
50	1					34
25	2					35
13	1					36
10	1					37
40	2					38
13	1					39
13	1					40

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Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	RACE STREET - GRAND RAPIDS	Trans Unattended	138.00	46.00	16.00
2	RAISIN - RAISIN	Trans Unattended	138.00	46.00	10.50
3	RAMONA - GRAND RAPIDS TWP	Distrib Unattended	46.00	12.47	
4	RANKIN - MUNDY TWP	Distrib Unattended	46.00	8.32	
5	RANSOM - JAMESTOWN	Trans Unattended	138.00	46.00	15.00
6	RAVENNA - RAVENNA TWP	Distrin Unattended	46.00	12.47	
7			46.00	8.32	
8	RAVINE - KALAMAZOO TWP	Distrib Unattended	46.00	8.32	
9	RED ARROW - BURTON TWP	Distrib Unattended	46.00	8.32	
10	REED CITY - ALGOMA TWP	Distrib Unattended	46.00	8.32	
11	REMUS - WHEATLAND TWP	Distrib Unattended	46.00	8.32	
12	RICE CREEK - SHERIAN	Trans Unattended	138.00	46.00	10.50
13	RIGGSVILLE - IVERNESS	Trans Unattended	138.00	46.00	5.25
14	RIVERTOWN - CITY OF GRANDVILLE	Distrib Unattended	138.00	12.47	
15	RIVERVIEW - RIVERVIEW	Trans Unattended	138.00	46.00	15.20
16	RIX ROAD - OSHTEMO TWP	Distrib Unattended	46.00	8.32	
17	ROBERTS STREET - BLACKMAN	Distrib Unattended	46.00	8.32	
18	ROCKFORD - ALGOMA TWP	Distrib Unattended	46.00	24.90	
19			46.00	8.32	
20	RODNEY - COLFAX TWP	Distrib Unattended	46.00	24.90	
21	ROEDEL ROAD - FRANKENMUTH TWP	Distrib Unattended	138.00	8.32	
22	ROSEWOOD - GEORGETOWN TWP	Distrib Unattended	46.00	12.47	
23	RUSSELLVILLE - RICHFIELD TWP	Distrib Unattended	46.00	8.32	
24	RUTLAND - RUTLAND TWP	Distrib Unattended	46.00	8.32	
25	SAGINAW RIVER - ZILWAUKEE	Trans Unattended	138.00	46.00	10.50
26			138.00	23.00	10.50
27	SAGINAW STREET - BURTON TWP	Distrib Unattended	46.00	8.32	
28	SALEM - SALEM TWP	Distrib Unattended	46.00	8.32	
29	SAMARIA - BEDFORD	Trans Unattended	138.00	46.00	7.60
30	SANDERSON - EUREKA TWP	Distrib Unattended	138.00	24.90	
31	SANFORD DAM - JEROME TWP	Distrib Unattended	46.00	24.90	
32			46.00	8.32	
33	SARANAC - BOSTON TWP	Distrib Unattended	46.00	8.32	
34	SAUGATUCK - SAUGATUCK TWP	Distrib Unattended	46.00	8.32	
35	SAVIDGE - SPRING LAKE TWP	Distrib Unattended	138.00	12.47	
36	SCOTT LAKE - LEE	Trans Unattended	138.00	46.00	7.50
37	SEIDEL - SAGINAW TWP	Distrib Unattended	46.00	8.32	
38	SHAFFER - PARIS TWP	Distrib Unattended	46.00	12.47	
39	SHATTUCK - SAGINAW TWP	Distrib Unattended	46.00	8.32	
40	SHIELDS - SWAN CREEK TWP	Distrib Unattended	46.00	8.32	

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SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
100	1					1
30	1					2
20	1					3
13	1					4
100	1					5
13	2					6
						7
13	1					8
27	2					9
18	2					10
12	2					11
40	1					12
30	2					13
32	2					14
200	2					15
10	2					16
20	1					17
33	2					18
						19
13	1					20
13	1					21
25	2					22
13	1					23
13	1					24
68	2					25
						26
40	2					27
13	1					28
78	2					29
14	1					30
13	2					31
						32
11	3					33
19	2					34
13	1					35
40	1					36
13	1					37
57	2					38
20	1					39
10	1					40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	SILVER LAKE - GARFIELD TWP	Distrib Unattended	46.00	12.47	
2	SIMMONS - WEST BRANCH TWP	Distrib Unattended	138.00	24.90	
3	SIMPSON - MENDON	Trans Unattended	138.00	46.00	10.50
4	SKYLARK - GRAND BLANC TWP	Distrib Unattended	46.00	8.32	
5	SLOAN - FLINT TWP	Distrib Unattended	46.00	8.32	
6	SOLVAY - MADISON TWP	Distrib Unattended	138.00	24.90	
7	SOUTH WASHINGTON AY - SAGINAW TWP	Distrib Unattended	46.00	8.32	
8	SPAULDING - ADA	Trans Unattended	138.00	46.00	15.00
9	SPRING ARBOR - SPRING ARBOR TWP	Distrib Unattended	46.00	8.32	
10	SPRING DRIVE - BROOKS TWP	Distrib Unattended	46.00	24.90	
11	SPRINGFIELD - BATTLE CREEK TWP	Distrib Unattended	46.00	8.32	
12	SPRINKLE - PORTAGE TWP	Distrib Unattended	46.00	8.32	
13	SQUIRE HILL - CLAYTON TWP	Distrib Unattended	46.00	8.32	
14	ST JOHNS - BINGHAM TWP	Distrib Unattended	46.00	8.32	
15	STACEY - FLINT TWP	Distrib Unattended	138.00	24.90	
16	STANDALE - WALKER TWP	Distrib Unattended	46.00	12.47	
17	STANDISH - LINCOLN TWP	Distrib Unattended	46.00	8.32	
18	STANLEY - MT MORRIS TWP	Distrib Unattended	46.00	8.32	
19	STATE STREET - SAGINAW TWP	Distrib Unattended	46.00	8.32	
20	STEEL DRIVE - FENTON TWP	Distrib Unattended	46.00	8.32	
21	STERNS ROAD - ERIE TWP	Distrib Unattended	46.00	12.47	
22	STEVENS - WYOMING TWP	Distrib Unattended	46.00	12.47	
23	STOCKBRIDGE - STOCKBRIDGE TWP	Distrib Unattended	46.00	8.32	
24	STONEGATE - GRAND RAPIDS TWP	Distrib Unattended	138.00	12.47	
25	STOVER - STOVER	Trans Unattended	138.00	46.00	5.25
26	STRAITS PLANT - WAWATAM	Trans Unattended	46.00	13.80	
27	STRONACH - STRONACH	Trans Unattended	138.00	46.00	7.59
28	SUMMERTON - CHIPPEWA	Trans Unattended	138.00	46.00	7.60
29	SUMMIT - SUMMIT TWP	Distrib Unattended	46.00	8.32	
30	SWARTZ CREEK - CLAYTON TWP	Distrib Unattended	46.00	8.32	
31	SYLVAN - SYLVAN TWP	Distrib Unattended	46.00	8.32	
32	TALLMAN - EAGLE TWP	Distrib Unattended	138.00	24.90	
33	TANIUM - MONTAGUE TWP	Distrib Unattended	46.00	12.47	
34	TECUMSEH - TECUMSEH TWP	Distrib Unattended	46.00	12.47	
35	TEFT - SWAN CREEK TWP	Distrib Unattended	46.00	8.32	
36	TEMPERANCE - BEDFORD TWP	Distrib Unattended	46.00	12.47	
37	TERRACE - MUSKEGON TWP	Distrib Unattended	46.00	12.47	
38	THOMAS - THOMAS TWP	Distrib Unattended	46.00	8.32	
39	THORNAPPLE - ADA TWP	Distrib Unattended	46.00	8.32	
40	TIHART - MERIDIAN	Trans Unattended	140.00	48.00	

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SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
13	1					1
13	1					2
38	1					3
25	2					4
13	1					5
13	1					6
13	1					7
100	1					8
10	1					9
13	1					10
10	1					11
25	2					12
10	1					13
13	2					14
13	1					15
25	2					16
10	1					17
13	1					18
13	1					19
13	2					20
14	1					21
13	2					22
14	1					23
45	2					24
50	1					25
25	1					26
30	1					27
70	2					28
13	1					29
13	1					30
13	1					31
11	1					32
13	1					33
18	2					34
10	1					35
13	1					36
10	1					37
13	1					38
13	2					39
90	2					40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1			138.00	46.00	7.59
2	TINSMAN - HOLLY TWP	Distrib Unattended	138.00	8.32	
3	TIPPY HYDRO - DICKSON TWP	Trans Unattended	150.00	7.50	
4	TITUS LAKE - WAYLAND TWP	Distrib Unattended	138.00	8.32	
5	TROWBRIDGE - TROWBRIDGE	Trans Unattended	138.00	46.00	5.25
6	TUCKER - HOLLY TWP	Distrib Unattended	46.00	8.32	
7	TWELFTH STREET - PORTAGE	Distrib Unattended	138.00	8.32	
8	TWILIGHT - COMSTOCK TWP	Distrib Unattended	138.00	8.32	
9	TWINING - TWINING	Trans Unattended	138.00	46.00	
10	ULMER - BIRCH RUN TWP	Distrib Unattended	46.00	8.32	
11	UPTON - DELTA TWP	Distrib Unattended	46.00	8.32	
12	VAN ATTA - MERIDIAN TWP	Distrib Unattended	138.00	8.32	
13	VANDERCOOK LAKE - SUMMIT TWP	Distrib Unattended	46.00	8.32	
14	VERONA - PENNFIELD	Trans Unattended	138.00	46.00	15.20
15	VEVAY - VEVAY TWP	Trans Unattended	138.00	46.00	7.60
16	VILLAGE GREEN - PORTAGE TWP	Distrib Unattended	46.00	8.32	
17	VIRGINIA PARK - LAKETOWN TWP	Distrib Unattended	46.00	8.32	
18	VROOMAN - SUMMIT	Trans Unattended	138.00	46.00	15.00
19	WACKERLY - WACKERLY	Trans Unattended	138.00	46.00	10.50
20	WAGER - GENESEE TWP	Distrib Unattended	46.00	8.32	
21	WALDO - MIDLAND TWP	Distrib Unattended	46.00	8.32	
22	WALKER - WALKER TWP	Distrib Unattended	46.00	12.47	
23	WALLACE - KALAMAZOO TWP	Distrib Unattended	46.00	13.80	
24	WALNUT - BURTON TWP	Distrib Unattended	46.00	8.32	
25	WARNER - PRAIREVILLE TWP	Distrib Unattended	138.00	24.90	
26	WARREN - WARREN TWP	Trans Unattended	138.00	46.00	10.50
27	WASHINGTON - PERE MARQUETT TWP	Distrib Unattended	46.00	12.47	
28			46.00	8.32	
29	WASHTENAW - CHELSEA	Trans Unattended	138.00	46.00	7.50
30	WATKINS - BATTLE CREEK TWP	Distrib Unattended	46.00	8.32	
31	WAYLAND - WAYLAND TWP	Distrib Unattended	138.00	48.00	5.25
32			46.00	8.32	
33	WEADOCK J C PLANT - WEADOCK J C	Trans Attended	138.00	46.00	7.50
34	WEALTHY STREET - WALKER TWP	Trans Unattended	138.00	46.00	
35			138.00	12.47	
36	WEBSTER - MT MORRIS TWP	Distrib Unattended	46.00	8.32	
37	WEST RIVER - GRAND RAPIDS TWP	Distrib Unattended	46.00	12.47	
38	WEST ROAD - LANSING TWP	Distrib Unattended	46.00	8.32	
39	WESTERN AVENUE - LAKETON TWP	Distrib Unattended	46.00	12.47	
40	WESTERVELT - ZILWAUKEE TWP	Distrib Unattended	46.00	8.32	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
13	1					2
15	1					3
13	1					4
20	1					5
13	1					6
13	1					7
12	1					8
30	4					9
13	1					10
13	1					11
12	1					12
13	1					13
200	2					14
40	1					15
25	2					16
13	1					17
60	1					18
67	2					19
13	1					20
13	1					21
20	1					22
20	1					23
18	2					24
11	1					25
30	1					26
16	6					27
						28
30	1					29
25	2					30
33	2					31
						32
200	2					33
220	9					34
						35
10	1					36
13	1					37
10	1					38
35	3					39
13	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WESTWOOD - BLACKMAN	Distrib Unattended	46.00	8.32	
2	WEXFORD - HARING	Trans Unattended	138.00	46.00	
3			46.00	15.00	
4	WHITE LAKE - MONTAGUE	Trans Unattended	140.00	48.00	10.50
5			138.00	46.00	7.60
6	WHITEHALL - MONTAGUE TWP	Distrib Unattended	46.00	12.47	
7			46.00	8.32	
8	WHITING J R PLANT - LUNA PIER	Trans Attended	138.00	46.00	10.50
9	WILDWOOD - BLACKMAN TWP	Distrib Unattended	46.00	8.32	
10	WILLARD - BIRCH RUN	Trans Unattended	138.00	46.00	
11	WILLIAMS - ALLEGAN TWP	Distrib Unattended	46.00	8.32	
12	WILMOTT - OSTEGO TWO	Distrib Unattended	46.00	8.32	
13	WISNER - BLACKMAN TWP	Distrib Unattended	46.00	8.32	
14	WOOD STREET - FLINT TWP	Distrib Unattended	46.00	8.32	
15	WYOMING PARK - WYOMING TWP	Distrib Unattended	46.00	12.47	
16					
17					
18	SUBSTATIONS SERVING RESALE CUSTOMERS				
19	CHELSEA - CHELSEA	Resale Distrib Unatt	46.00	8.32	
20	EATON RAPIDS - EATON RAPIDS	Resale Distrib Unatt	46.00	8.32	
21	EATON RAPIDS MUNICIPAL - EATON RAPIDS	Resale Distrib Unatt	46.00	12.47	
22	PROGRESS STREET - ALPENA	Resale Distrib Unatt	138.00	12.47	
23	ST LOUIS - ST LOUIS	Resale Distrib Unatt	46.00	8.32	
24			46.00	4.16	
25					
26					
27	SUMMARY INFORMATION				
28					
29	SUBSTAIONS GREATER THAN 10,000 KVa	533			
30					
31	SUBSTATIONS SERVING ONE CUSTOMER	234			
32					
33	SUBSTATIONS LESS THAN 10,000KVa	266			
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
10	2					1
77	5					2
						3
88	2					4
						5
24	3					6
						7
38	1					8
13	2					9
30	1					10
12	2					11
13	1					12
10	1					13
13	1					14
13	1					15
						16
						17
						18
10	1					19
6	1					20
20	1					21
10	1					22
16	2					23
						24
						25
						26
						27
						28
15456	785	4				29
						30
3965	351	2				31
						32
1366	315	17				33
						34
						35
						36
						37
						38
						39
						40

ELECTRIC DISTRIBUTION METERS AND LINE TRANSFORMERS

1. Report below the information called for concerning distribution watt-hour meters and line transformers.
2. Include watt-hour demand distrubution meters, but not external demand meters.
3. Show in a footnote the number of distribution watt-hour meters or line transformers held by the respondent under lease from others, jointly owned with others, or held otherwise than by reason of sole ownership by the respondent. If 500 or more meters or line transformers are held under a lease, give name of lessor, date and period of lease, and annual rent. If 500 or more meters or line transformers are held other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of accounting for expenses between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Item (a)	Number of Watt-Hour Meters (b)	LINE TRANSFORMERS	
			Number (c)	Total Capacity (In MVa) (d)
1	Number at Beginning of Year	1,817,765	593,562	
2	Additions During Year			
3	Purchases	61,355	17,546	
4	Associated with Utility Plant Acquired			
5	Total Additions *(Enter Total of lines 3 and 4)*	61,355	17,546	
6	Reductions During Year			
7	Retirements	49,240	(6,430)	
8	Associated with Utility Plant Sold			
9	Total Reductions *(Enter Total of lines 7 and 8)*	49,240	(6,430)	
10	Number at End of Year (Lines 1+5-9)	1,829,880	604,678	
11	In Stock	39,117		
12	Locked Meters on Customers' Premises	64,000		
13	Inactive Transformers on System		32,273	
14	In Customers' Use	1,726,763	572,405	
15	In Company's Use	-	-	
16	TOTAL End of Year *(Enter Total of line 11 to 15. This line should equal line 10.)*	1,829,880	604,678	

ENVIRONMENTAL PROTECTION FACILITIES

1. For purposes of this response, environmental protection facilities shall be defined as any building, structure, equipment, facility, or improvement designed and constructed solely for control, reduction, prevention or abatement of discharges or releases into the environment of gaseous, liquids, or solid substances, heat, noise or for the control, reduction prevention, or abatement of any other adverse impact of an activity on the environment.

2. Report the differences in cost of facilities installed for environmental considerations over the cost of alternative facilities which would otherwise be used without environmental considerations. Use the best engineering design achievable without environmental considerations. It is not intended that special design studies be made for purposes of this response. Base the response on the best engineering judgement where direct comparisons are not available.

Include in these differences in costs the costs or estimated costs of environmental protection facilities in service, constructed or modified in connection with the production, transmission, and distribution of electrical energy and shall be reported herein for all such environmental facilities placed in service on or after January 1, 1969, so long as it is readily determinable that such facilities were constructed or modified for environmental rather than operational purposes. Also report similar expenditures for environmental plant included in construction work in progress. Estimate the cost of facilities when the original cost is not available or facilities are jointly owned with another utility, provided the respondednt explains the basis of such explanations. Examples of these costs would include a portion of the costs of tall smokestackes, underground lines, and landscaped substations. Explain such costs in a footnote.

3. In the cost of facilities reported on this page, include an estimated portion of the cost of plant that is or will be used to provide power to operate associated environmental protection facilities. These costs may be estimated on a percentage of plant basis. Explain such estimations in a footnote.

4. Report all costs under the major classifications provided below and include, as a minimum, the items listed hereunder:

A. Air pollution control facilities:
(1) Scrubbers, precipitators, tall smokestacks, etc. (2) Changes necessary to accommodate use of environmentally clean fuels such as low ash or low sulfer fuels including storage and handling equipment. (3) Monitoring Equipment (4) Other.

B. Water pollution control facilities:
(1) Cooling towers, ponds, piping, pumps, etc. (2) Waste water treatment equipment (3) Sanitary waste disposal equipment (4) Oil interceptors (5) Sediment control facilities (6) Monitoring equipment (7) Other.

C. Solid waste disposal costs:
(1) Ash handling and disposal equipment (2) Land (3) Settling ponds (4) Other.

D. Noise abatement equipment:
(1) Structures (2) Mufflers (3) Sound proofing equipment (4) Monitoring equipment (5) Other.

E. Esthetic costs:
(1) Architectural costs (2) Towers (3) Underground lines (4) Landscaping (5) Other.

F. Additional plant capacity necessary due to restricted output from existing facilities, or addition of pollution control facilities.

G. Miscellaneous:
(1) Preparation of environmental reports (2) Fish and wildlife plants included in Accounts 330, 331, 332, and 335 (3) Parks and related facilities (4) Other.

5. In those instances when costs are composites of both actual supportable costs and estimates of costs, specify in column (f) the actual costs that are included in column (e).

6. Report construction work in progress relating to environmental facilities at line 9.

Line No.	Clasification of Cost (a)	CHANGES DURING YEAR Additions (b)	Retirements (c)	Adjustments (d)	Balance at End of Year (e)	Actual Cost (f)
1	Air Pollution Control Facilities	43,365,671			756,443,342	
2	Water Pollution Control Facilities	559,496	323,078		237,265,168	
3	Solid Waste Disposal Costs	28			78,825,212	
4	Noise Abatement Equipment	-			1,538,548	
5	Esthetic Costs	-			26,944,000	
6	Additional Plant Capacity	-			14,286,000	
7	Miscellaneous *(Identify significant)*	1,106,604			101,226,741	
8	TOTAL *(Total of lines 1 thru 7)*	45,031,799			1,216,529,011	
9	Construction Work in Progress				187,182,724	

Miscellaneous (Line 7):	Yr 2004
Environmental Protection	
Fossil Plants 316b Fish Entrainment	60,858
K/W/CT's SPCC Oil Containment	377,115
JRW Oil Containment	49,727
LPS Oil Containment	13,140
Recreation License Initiative - LPS Barrier Net/Monitoring	77,263
Flood & Erosion Control Protection	
Hydro Plt Flow Gauging/Water Qual Monitoring & Comm System	10,455
Spillway Mods - Hodenpyl & Mio	518,046
Total	1,106,604

ENVIRONMENTAL PROTECTION EXPENSES

1. Show below expenses incurred in connection with the use of environmental protection facilities, the cost of which are reported on page 430. Where it is necessary that allocations and/or estimates of costs be made, state the basis or method used.
2. Include below the costs incurred due to the operation of environmental protection equipment, facilities, and programs.
3. Report expenses under the subheadings listed below.
4. Under item 6 report the difference in cost between environmentally clean fuels and the alternative fuels that would otherwise be used and are available for use.
5. Under item 7 include the cost of replacement power, purchased or generated, to compensate for the deficiency in output from existing plants due to the addition of pollution control equipment, use of alternate environmentally preferable fuels or environmental regulations of governmental bodies. Base the price of replacement power purchased on the average system price of purchased power if the actual cost of such replacement power is not known. Price internally generated replacement power at the system average cost of power generated if the actual cost of specific replacement generation is not known.
6. Under item 8 include ad valorem and other taxes assessed directly on or directly relatable to environmental facilities. Also include under item 8 licensing and similar fees on such facilities.
7. In those instances where expenses are composed of both actual supportable data and estimates of costs, specify in column (c) the actual expenses that are included in column (b).

Line No.	Classification of Expenses (a)	Amount (b)	Actual Expenses (c)
1	Depreciation		
2	Labor, Maintenance, Materials, and Supplies Cost Related to Env. Facilities and Programs	11,441,787	11,441,787
3	Fuel Related Costs		
4	Operation of Facilities		
5	Fly Ash and Sulfur Sludge Removal	1,217,038	1,217,038
6	Difference in Cost of Environmentally Clean Fuels (1)	(191,518,000)	
7	Replacement Power Costs (2) W/Palisades	8,391,000	8,391,000
8	Taxes and Fees		
9	Adminstrative and General		
10	Other *(Identify significant)*		
11	TOTAL	(170,468,175)	21,049,825

(1) Estimate based on the difference between the actual cost of environmentally preferable low-sulfur fuels and the estimated cost of high-sulfer fuels. The market price of high sulfur fuels increased significantly in 2004.

(2) Based on the average price of interchange power. Energy cost of electrostatic precipitators is included utilizing the average production cost for the year.

FOOTNOTE DATA

Page Number (a)	Item Number (b)	Column Number (c)	Comments (d)
Various	Various	Various	Amounts on schedules may not add to the totals and/or cross-referenced schedules may not reconcile due to roundings.

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